National Electric Power Regulatory Authority
Islamic Republic of Pakistan

Registrar

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No: NEPRA/R/DG(Lic)/LAT-01/1550-90 February 01, 2023

Managing Director
National Transmission & Despatch Company Limited
414 WAPDA House, Sharah-e-Quaid-e-Azam
Lahore

Subject: **DETERMINATION OF THE AUTHORITY IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN OF NATIONAL TRANSMISSION AND DESPATCH COMPANY LIMITED (IGCEP – 2022-31)**

Reference: NTDC letter No. GMT/NTDC/T-48/596-602 dated 20.09.2022

Please find enclosed the determination of the Authority in the matter of Indicative Generation Capacity Expansion Plan (IGCEP 2022-31) (16 pages) alongwith copy of Approved IGCEP 2022-31 (**Annex-I**) and Comments of Stakeholder (**Annex-II**) for your reference, record and necessary action. The said documents are also available at NEPRA website i.e. www.nepra.org.pk

Encl: **As Above**

01/02/23
(Engr. Mazhar Iqbal Ranjha)
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1.	Secretary, Cabinet Division, Government of Pakistan Cabinet Secretariat, Islamabad	2.	Secretary Power Division, Ministry of Energy Government of Pakistan 'A' Block, Pak Secretariat, Islamabad
3.	Secretary Economic Affairs Division 'C' Block, Pak Secretariat, Islamabad	4.	Secretary Ministry of Planning & Development Government of Pakistan 'P' Block, Pak Secretariat, Islamabad
5.	Secretary Privatization Commission, Ministry of Privatization, Government of Pakistan, 4th Floor, Kohsar Block, Pak Secretariat, Islamabad	6.	Secretary Water & Power Government of Gilgit Baltistan Near Kara Kuram International University Gilgit
7.	Secretary Energy Department Government of Punjab EFU House, 8th Floor, 6-D Jail Road, Lahore	8.	Secretary Energy Department, Government of Sindh 3rd Floor, Start Life Building -3 Dr. Zia-ud-din Ahmed Road, Karachi

33.	Mr. Rafique Khanani Authorized Representative Artistic Milliners (Pvt) Limited 4/1-4/2, Deh Landhi Bin Qasim Town, Karachi	34.	Mr. Danish Khaliq Head of Business Development Hub Power Holding Company 9th Floor, Ocean Tower Block-9, Main Clifton Road, Karachi
35.	Mr. Mohsin Bilal Chief Executive Officer Neelum Green Energy (Pvt.) Ltd 1st Floor, 2-D, I&T Centre Khayaban-e-Sorwardi, G-6/1, Islamabad	36.	Syed M. Ghazanfar Alternative Law Collective House No. 134, Street No. 11 Cavalry Ground, Lahore
37.	Mr. Hamza Bashir Indus Consortium House No. 1043, Street No. 45B E-11/3, Islamabad	38.	Mr. Sangwoo Kim Chief Executive Officer LSG Hydro Power Limited Office No. 29, 3rd Floor, Executive Complex G-8 Markaz, Islamabad
39.	Chief Executive Officer Jamsoro Power Company Limited Mohra Jabal, Dadu Road Jamshoro	40.	Chief Executive Officer Central Power Generation Company Limited Thermal Power Station, Barrage Road Guddu, District Kashmore
41.	Chief Executive Officer, Northern Power Generation Company Limited, Mehmood Kot Road, TPS, Muzaffargarh		

9.	Secretary Energy & Power Department Government of Khyber Pakhtunkhwa First Floor, A-Block, Abdul Wali Khan Complex Civil Secretariat, Peshawar	10.	Secretary Energy Department Government of Balochistan Civil Secretariat, Zarghoon Road Quetta
11.	Chief Executive Officer Central Power Purchasing Agency Guarantee Ltd 73 East, A.K. Fazl-ul-Haq Rd Blue Area, Islamabad	12.	Chairman Pakistan Water and Power Development Authority (WAPDA) WAPDA House, Lahore
13.	Managing Director Private Power & Infrastructure Board (PPIB) Ground & 2nd Floors, Emigration Tower, Plot No. 10, Mauve Area, Sector G-8/1, Islamabad	14.	Chief Executive Officer Alternative Energy Development Board 2nd Floor, OPF Building G-5/2, Islamabad
15.	Managing Director Punjab Power Development Board Old Anarkali, 1st Floor Irrigation Secretariat, Lahore	16.	Chief Executive Officer Pakhtunkhwa Energy Development Organization PEDO House, 38/B-2, Room No. 105, Hayatabad, Phase-V, Peshawar
17.	Chief Executive Officer Lahore Electric Supply Company (LESCO) 22-A, Queen Road, Lahore	18.	Chief Executive Officer Gujranwala Electric Power Company (GEPCO) 565/A, Model Town, G.T Road, Gujranwala
19.	Chief Executive Officer Multan Electric Power Company (MEPCO) NTDC Colony, Khanewal Road, Multan	20.	Chief Executive Officer Peshawar Electric Supply Company (PESCO) NTDC House, Shami Road, Peshawar
21.	Chief Executive Officer K Electric (KEL) KE House, 39 B Main Sunset Boulevard, LCMPL Phase-II, Karachi	22.	Chief Executive Officer Quetta Electric Supply Company (QESCO) Zarghoon Road, Quetta
23.	Chief Executive Officer Islamabad Electric Supply Company (IESCO) IESCO Head Office Street 40 Sector G-7/4, Islamabad	24.	Chief Executive Officer Faisalabad Electric Supply Company (FESCO) Abdullahpur, Canal Bank Road, Faisalabad
25.	Chief Executive Officer Sukkur Electric Supply Company (SEPCO) Old Thermal Power Station, Sukkhur	26.	Chief Executive Officer Hyderabad Electric Supply Company (HESCO) HESCO Headquarter WAPDA Complex, Hussainabad, Hyderabad
27.	Chief Executive Officer Tribal Areas Electricity Supply Company (TESCO) 213-NTDC House Shami Road, Peshawar	28.	Mr. Muhammad Shomail Ghalib Chief Executive Officer Access Solar (Private) Limited C/o Horwath Hussain Ch. & Co 25 E Main Gulberg Market Lahore
29.	Mr. Muhammad Shomail Ghalib Chief Executive Officer Access Electric (Private) Limited C/o Horwath Hussain Ch. & Co 25 E Main Gulberg Market Lahore	30.	Syed M. Hussain Gardezi Director (Development) Riali Hydro Power Company (Pvt) Ltd 59-E, Street-7, Sector I-10/3 Islamabad
31.	Mr. Umar Shehzad Shaikh Chief Executive Officer Altern Energy Limtied 18-KM, Ferozpur Road, Lahore	32.	Mr. Aaali Muazzam Chief Executive Officer Habilullah Coastal Power Company D-180, Block-5 Clifton Karachi

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

February 01, 2023
Case No. LAT-01

(A). Background

(i). The Authority granted a Transmission Licence (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 functions under the above Transmission Licence.

(ii). In consideration of the above, NTDC prepared a Grid Code and the Authority approved the same in June, 2005. According to the Planning Code (PC4) of the Grid Code, NTDC is required to prepare and submit a Ten Year Indicative Generation Capacity Expansion Plan (IGCEP), covering time frame of 0-10 years, identifying the new capacity requirement.

(B). Submission & Processing of IGCEP

(i). In consideration of the above, NTDC prepared and submitted IGCEP for the period 2022-31 vide its letter No. GMT/NTDC/T-48/596-602, dated September 20, 2022 for consideration and approval of the Authority.

(ii). The Authority considered the matter 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 September 27, 2022 informing about submission of the IGCEP and for submitting comments in the matter before or during the Public Hearing.

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(iii). In light of the above, the Authority received comments of around twenty nine (29) stakeholders including various developers, representative organizations, Govt. Ministries and attached departments. The stakeholders included Access Solar (Pvt.) Limited (ASPL), Access Electric (Pvt.) Limited (AEPL), Riali Hydro Power Company (Pvt.) Limited (RHPCPL), Altern Energy Limited (AEL), Atlas Power Limited (APL), Mr. Arif Bilwani, Dr. M. Ilyas Fazil, Gujranwala Electric Power Company Limited (GEPCO), Habibullah Coastal Power Company (Pvt.) Limited (HCPCL), Lahore Electric Supply Company Limited (LESCO), Pakhtunkhwa Energy Development Organization (PEDO), Siddiqsons Limited (SSL), Artistic Milliner (Pvt.) Limited (AMPL), Hub Power Company Limited (HUBCO), Neelum Green Energy (Private) Limited (NGEPL), Wärtsilä Corporation/Wartsila Pakistan (Pvt.) Limited (Wartsila), Alternative Law Collective (ALC), Indus Consortium (IC), K-Electric Limited (KEL), LSG Hydro Power Limited (LSGHPL), Pakistan Renewable Energy Coalition (PREC), Dr. Peter Meier, Pakistan Initiative on Energy (PIE), Jamshoro Power Company Limited (JPCL). Central Power Generation Company Limited (CPGCL), Northern Power Generation Company Limited (NPGCL), Alternative Energy Development Board (AEDB), Energy Department Govt. of Sindh (EDGoS) and Energy Department Govt. of Balochistan (EDGoB).

(iv). The above stakeholders *inter alia* made various observations on the submitted IGCEP including (a). projects of size less than 20.00 MW earlier considered as "Committed" have not been included in the current version of IGCEP-2022-31 and this exclusion may cause hindrance/bottleneck in the development/implementation of such projects; (b). the Authority has relied on IGCEP as a pre-condition for issuing tariff, however NTDC has repeatedly mentioned that the plan is non-committal however, it must take responsibility for the optimized projects as stipulated in the Grid Code; (c). the costs relating to power system evacuation for optimized projects have not been considered and this may impact selection/optimization or ranking of the optimized project. Therefore, preparation of Transmission System Expansion Plan (TSEP) is equally critical for planning as is IGCEP; (d). the IGCEP has envisaged very aggressive induction of solar to the tune of around 12,000 MW which is intermittent in nature and has operational and

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technical challenges relating to integration with the grid hampering network reliability and stability. There is need to study the grid and make decisions accordingly instead of rushing into such projects that can have unintended consequences; (e). IGCEP has not considered the existing projects set up under the Power Policy 1994 in the installed capacity due to termination of Gas Supply Agreement (GSA) or the expiry of the term of the licence which needs to be reconsidered; (f). Waste to Energy (WtE) projects are of strategic nature and introduction to "new technology" that should be added to the Candidate list of IGCEP; (g). the project of Taunsa must be marked as a 'committed' project as if to be commissioned in 2028-29, the work has to be started from the year 2023 and without adding it in the committed list financing cannot be obtained; (h). IGCEP envisages a strategy to phase out the use of Furnace Oil completely for power generation by 2027 however, this approach may not be appropriate considering the fact that huge investment has been done in the refineries; (i). there are a number of remotely located projects requiring long transmission line(s) involving huge cost which needs to be considered; (j). the data used in IGCEP along with its collection and calculation methodologies should be made publicly available on the websites of concerned institutions; (k). a considerable number of large dams have been proposed to be built are located in earth quick areas and it is not clear that cost of dynamic risks for such initiatives have been considered or not? (l). the plants of GENCO(s) have been excluded despite the fact that matter of closing of these units is sub judice in the court. The operation of plants of GENCO-I, II and III may be considered instead of HUBCO and accordingly the retirement plant may be reconsidered; (m). has the impact of Captive Power Plants of industries and those of other third party generation facilities installed at the premises of industrial units for supplying to the said entities been duly considered or not? (n). the delay in completion of Hydro Power Plant (HPP), the seasonal and climatic variation in the hydel generation may be considered; (o). the retirement of power plants operating on indigenous low BTU gas should be based on the availability of the gas and techno commercial analysis instead of expiry of the PPA; (p). projects of 470 MW Lower Spat Gah, 102 MW Shigo Kas, 99 MW Arkari Gol and other five (05) solar PV projects of Khyber Pakhtunkhwa should be included in the IGCEP; (q). the feasibility of the results from PLEXOS long-term expansion model be tested with another function of

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the software, which is the short-term modelling for more detailing and to see how the system will dispatch in a smaller step size with a given capacity and also more dynamic properties of power plants may be included in the model; (r). new-built technology candidate options, such as flexible multi-fuel engines, energy storage, or flexible demand may be considered; (s). the requirement of competitive electricity market has not been accounted for in the IGCEP and the linkage with the Competitive Trading Bilateral Contract Market (CTBCM) is missing; and (t). five (05) wind projects, coal project of Oracle, Waste to Energy (WtE) projects may be included in the IGCEP. Apart from the above, various developers made the observation that the cost their projects have not been taken as per their submissions.

(C). Public Hearing

(i). The Authority conducted the Public Hearing in the matter which was held on October 19, 2022 at its main office in Islamabad and was attended by various stakeholder both in person and via zoom link, inter alia, including NTDC/NPCC, CPPA-G, Pakistan Atomic Energy Commission (PAEC), Power Division, Ministry of Energy (PDMoE), Ministry of Planning, Development and Special Initiatives (MoPD&SI), AEDB, Private Power & Infrastructure Board (PPIB), PEDO, Punjab Power Development Board (PPDB), EDGoS, EDGoB, Azad Jammu and Kashmir Power Development Organization (AJ&KPDO), KEL, Wartsila, representatives of various project developers, media persons and the representative of general public at large.

(ii). The representatives of NTDC gave a detailed presentations on the salient features of the submitted IGCEP-2022-31 and gave a comparison of the current with the earlier version IGCEP-2021-30. The summary and comparison of the main features of two version of the IGCEP is as detailed below: -

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Sr. No.	Description	IGCEP-2021		IGCEP-2022	
(1).	Number of Scenarios	01 (Base Case)		01 (Base Case) + 06	
(2).	Main Scenario	Normal: 5.134% GDP growth rate (MoF)		Normal: 4.30% GDP Growth Rate (WB)	
(3).	Existing Demand (Peak and Total)	23,792 MW (2020-21)	130,652 GWh (2020-21)	26,945 MW (2021-22)	153,886 GWh (2021-22)
(4).	Installed Capacity (Existing)	34,776 MW (NTDC)		37,949 MW (NTDC) + 3,319 MW (KE) = 41,268 MW	
(5).	Committed Projects	22,415 MW (73 Projects)		14,159 MW (30+1 Projects)	
(6).	Net-Metering (Committed)	-		4,320 MW	
(7).	Candidate Projects	10,062 MW (NTDC)		15,340 MW (NTDC) + 2,472 MW (KE) =17,812 MW	
(8).	Projects < 20 MW considered?	Yes		No	
(9).	Retirements	6,447 MW (NTDC)		7,339 MW (NTDC) + 682 MW (KE) = 8,021 MW	
(10).	Installed Capacity (Final Year)	61,112 MW		69,372 MW	
(11).	Demand (Normal) (Peak and Total)	37,129 MW (2029-30)	207,418 GWh (2029-30)	41,338 MW (2030-31)	228,505 GWh (2030-31)

(iii). The representatives of NTDC explained that the IGCEP 2022-31 presents the results of the generation capacity expansion planning study which is composed of two key processes (a). Load forecast; followed by (b) Generation

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capacity expansion and despatch optimization and both processes involve complex statistical and computation efforts performed using dedicated software programs. Three scenarios of long-term forecast, as per prevailing Grid Code, have been prepared for the Low, Normal and High GDP growth of 3.40%, 4.30% and 5.42% respectively. The least cost, long-term generation expansion plan for the power system is developed using state-of-the-art generation planning software - PLEXOS. The IGCEP 2022-31 is developed through a rigorous data modelling and optimization exercise based on the existing and future generation power projects, existing policy framework, existing contractual obligations, natural resource allocations, relevant provisions of prevailing Grid Code, and assumptions laid down in National Electricity Policy 2021 (NEP) along with some additional assumptions.

(iv). The base case scenario is developed on normal scenario of long-term forecast, existing contractual obligations and retirements of power projects, during the planning horizon of the IGCEP, as per terms of their respective Power Purchase Agreement (PPA), except KAPCO. In the study, 8,021 MW of existing power generation capacity is retired during the plan horizon, in every scenario. Further, for the purpose of sensitivity analysis, six (06) scenarios are also developed, in addition to the base case scenario, which include (a). Low Demand Scenario; (b). High Demand Scenario; (c). Diamer Bhasha HPP in 2029; (d). Chashma Nuclear (C-5) for Energy Security; (e). Local coal inclusion in 2027 and 2030; and (f). Unconstrained Variable Renewable Energy (VRE) Scenario. Hourly demand forecast is developed specially to cater for the intermittency of VRE resources such as wind and solar PV. This is particularly important in view of the aggressive targets pertaining to renewable energy envisioned by the Government of Pakistan. Hence, the energy and peak demand forecast of 87,600 hours have been estimated form the FY 2022 to FY 2031. In the base case, the demand and installed capacity of the whole country is 41,338 MW and 69,372 MW, respectively by the year 2031. It is to highlight that in the said installed capacity, the optimized share from VRE resources include 8,350 MW_P of Solar PV (utility solar & feeder based/DG) and 4,928 MW of Wind. Apart from VRE(s), 3,544 MW of hydro and 990 MW of local coal has been optimized. It is pertinent to mention that the optimized local coal can be installed in any of the three blocks of

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Thar i.e., Block-I, II & VI, based on the assumption that the price at all three blocks of Thar will be the same. It was added that 4,320 MWp net metering solar is also included in the system i.e., 480 MWp, every year. Consequently, salient features of the base case include (a). aggressive inclusion of VRE(s); (b). Minimal reliance on imported fuels i.e., Coal, RLNG and Residual Furnace Oil (RFO) based technologies; (c). increased share of hydropower as well as local coal; and (d). All optimized generation is based on indigenous resources.

(v). The Authority afforded an opportunity to those stakeholders who wished to express themselves. Most of the stakeholders reiterated their comments a summary of which is explained in the preceding paragraphs. In addition to the said, a few stakeholders including the representatives of PAEC and sponsors of the projects of Artistic Hydro and Shigo Kas. The representative of PAEC submitted that on April 20, 2015, the Framework Agreement on Future Nuclear Power Plants [NPP(s)] was signed for C-5 NPP in the presence of President of Pakistan and President of China. On November 21, 2017, with approval of Prime Minister of Pakistan, EPC Contract of C-5 was signed at the agreed EPC Price of RMB 25,780.00 Million. At this point, financial closure is almost completed, with only exception that PAEC is trying to get Chinese loan at lowest possible interest rate. Consequently, C-5 maintained a committed project status for development and the same status was considered by NTDC for IGCEP 2019, IGCEP 2020 and in the initial version (i.e. draft) of IGCEP 2021. Later, in the revised IGCEP-2021 that was also approved by the relevant authority, C-5 committed status was changed to a candidate project. Now in the submitted IGCEP-2022, long operation life (i.e. generation benefits) of NPP of C-5 are quashed by taking a discount rate of 10.0%. The proposed loan for C-5 is a concession loan with a very low interest rate. Keeping in view the above listed benefits and incentive on loan for C-5, it might be fair to apply a discount rate around 3.0%.

(vi). The representative of PAEC stated that the operating cost (O&M+ Fuel cost) is the least among all thermal power technologies. This makes NPP the most economical and suitable base-load power generation option. The NPP(s) are globally recognized as energy supply option to handle the greenhouse gases (CHG) emission

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(vii). The representatives of AMPL reiterated its earlier comments on the importance of the TSEP and in the absence of the said, the final costs of the project cannot be accurately determined which will be against the spirit of NEP which stipulates that the expansion in generation capacity shall be only on a competitive and least-cost basis (except for strategic projects). Unfortunately, the above principle has not applied on the selection of our project of Artistic Hydro II. The said project has its annualized cost of energy determined under the IGCEP is lower than multiple hydro sites which have been optimized however, the above project has not been optimized. The technology of HPP(s) is similar and yet, different economic life [ranging from thirty (30) to hundred (100) years] has been used for different candidate HPP(s). Therefore, NTDC should either consider the economic life of all these candidate hydro sites as thirty years [the concession period for HPP(s)] or the full economic life for all projects. Most of the hydro sites are run-of-the-river as cascade projects and in the absence of TSEP, the criteria used by NTDC to select hydro sites might skip multiple projects which are coming on the same river cascade where cost allocation of a single transmission line for the entire corridor could make them highly feasible. The representatives of Shigo Kas expressed that its project is cheaper when compared to other similar project like Arkari Gol but the same has not been optimized. In this regard, it was highlighted that for the project of Arkari Gol, the maximum capability of the generation facility has been take as 97.50 MW at a constant level which is practically not possible. Further, there is no information on the dispersal and interconnection arrangement whereas the project of Shigo Kas is only twenty (20)

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kilometer from the nearest grid making it a string candidate for the selection on least cost expansion basis but have not been optimized.

(viii). The Authority considered the above submission of the stakeholders and directed NTDC to have consultations and address their concerns. In this regard, NTDC arranged meetings with PEDO, AEDB, PPDB, KEL and AJ&KPDO on October 31, 2022, November 03, 04 and 11, 2022. After detailed deliberation it was decided that the projects (with less than 20 MW installed capacity) considered committed in the previous approved IGCEP-2021-30, will be maintained with the same status in the current version of IGCEP-2022-31. Further, after going through a series of meetings, PEDO confirmed that the data provided at the time of formulation of database for the IGCEP is as per the Panel of Expert (PoE) approved feasibility study and there is no change in the same and observations made by the sponsors of Artistic-II HPP and ShigoKas HPP do not need consideration at this stage. NTDC held meeting with KEL on October 31, 2022 to address its concerns. In this regard, it was unanimously agreed that Take or Pay contracts for SNPCL and BQPS-III projects will be considered in the next iteration of IGCEP. Regarding the committed projects of KEL, it was agreed that the same will be considered as 'candidate' as per the earliest year of availability and will be subject to optimization in next iteration. Further, the quantum of net metering subtracted from load forecast of KEL shall be provided and the same will be considered in the next iteration. In order to address the observations of AEDB, a meeting was held on November 4, 2022 wherein it was confirmed that quantum pertaining to net metering of 480 MW indicated in the IGCEP includes the whole country. Accordingly, the revised quantum of net metering excluding KEL will be 370 MW_P. On the proposal of AEDB for considering block allocation of 100 MW annually, for other new technologies including but not limited to W_tE etc., In this regard, NTDC assured inclusion of the same in next iteration subject to provision of required data from the executing agencies for input of the software. Further to the above, NTDC had a meeting with PPDB on October 31, 2022 wherein it was agreed that the projects with less than 20.00 MW installed capacity considered as committed in the already approved IGCEP-2021-30, will also be included as committed in the current IGCEP-2022-31. Accordingly, NTDC through its letter No.

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GMT/NTDC/T-48/1356-63, dated December 02, 2022 submitted a revised IGCEP 2022-31 after incorporating/addressing the various observations of different stakeholders as explained above.

(D). Findings of the Authority

(i). The Authority has considered the entire case in detail including the submitted IGCEP-2022-31, comments of the stakeholders, issues arising out the said comments, peer review, proceedings of the Public Hearing, presentation/rejoinders of NTDC on comments of different stakeholders, minutes of meetings of different executing agencies and KEL with NTDC after the Public Hearing, the results of the revised run of the IGCEP-2022 and other facts related to the matter including the findings of the external consultants engaged. In this regard, the findings of the Authority are described in the following paragraphs.

(ii). NTDC has considered three (03) main Scenarios for the IGCEP-2022-31 as per the industry standard practice. The Scenario-I is the Base Case/Normal growth, Scenario-II is Low Demand Forecast and Scenario-III is the High Demand Forecast. According to the IGCEP, the GDP of the country is estimated to be 4.30% (Scenario-I/Base Case/Normal growth), 3.40% (Scenario-II/Low growth) and 5.42% (Scenario-III/High growth) respectively. Apart from the above mentioned standard Scenarios, NTDC has also developed four (04) more scenarios for sensitivity analysis purpose which include (a). Diamer Bhasha HPP in 2029; (b). C-5 for Energy Security in 2029; (c). Local coal projects of 1320 MW each in 2027 and 2030; and (d). Unconstrained VRE respectively.

(iii). Under the Base Case/Normal Growth/Scenario-I, the Peak Demand of the System in the year 2031 will be 41,338 MW against 26,945 MW in 2022. Further, the total energy consumption in 2031 is expected to reach 228,505 GWh, against 153,866 GWh in 2022. The current installed capacity of the system is 41,268 MW which will become 68,667 MW in the year 2031. This will include the existing capacity of the system (41,261 MW), addition of the already committed projects of 14,268 MW, 3,330 MW addition from net-metering and candidate projects of 17,969

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MW. In addition to the said, existing projects of 8,021 MW will be retired on completion of the term of their agreements etc. during the period of the revised IGCEP-2022.

(iv). Regarding committed projects, the IGCEP has considered a total of Forty-two (42) committed projects of various technologies including Hydel (8,192 MW), Local Coal (2,280 MW), Imported Coal (660MW), RLNG (1,263 MW) and VRE including Wind (100 MW), Solar (430 MW) and Bagasse (32 MW). In addition to the said 3,330 MW from net-metering and 310 MW capacity enhancement from refurbishment of Mangla HPP have also been considered under the committed capacity. Further, to the said, the committed projects also include a 1000 MW Cross Border import (CASA Project). The review of the list of the committed projects reveals that the same is compliant with the provisions of the decision of the CCI as the committed projects in the Private Sector are having LOS and the committed projects in Public Sector have their PC-I approved from the relevant entity/forum.

(v). Regarding the optimized power projects, it is noted that in the base case the IGCEP has considered 17,969 MW for a total of 46 projects of various technologies along with different blocks of wind and solar for the period 2024-2031. In this regard, the IGCEP has optimized a capacity addition of 8,564 MW_P of Solar PV (including utility scale and feeder based/DG), 4,827 MW Wind, 3,588 MW Hydro and 990 MW Local Coal, throughout the study horizon.

(vi). According to the IGCEP-2022-31, more than 77% of the installed capacity of the country by 2031, will be based on indigenous resources. Further, more than 80% of the indigenous resources will be ARE technologies of Hydel, Wind, Solar and Bagasse which is very encouraging. Further, there is emphasis to develop and utilize local coal which will result in increasing its contribution to around 7% by 2031. The Authority has observed that the dependence on imported fuel (including RLNG, RFO and imported coal) will drastically reduce from current 45% to less than 23% in the year 2031. In view of the said, it is clear that the IGCEP is not only based on environment friendly ARE technologies but has also envisaged to utilize other locally available resources.

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(vii). In view of the changing global dynamics there is a trend that indigenous resources of energy are made priority instead of dependence on imported fuel. In this regard, NTDC has considered the same in the sensitivity analysis by considering C-5 project of 1200 MW in 2029 and 2x1320 MW Local Coal projects in 2027 & 2030 respectively. However, NTDC has dropped projects of around 450 MW on bagasse due to litigation issues and resultantly lack of interest of the sponsors.

(viii). The Authority engaged the service of external experts including Wartsila and the Danish Energy Association (DAE). In this regard, Wartsila gave its findings using the same tool of PLEXOS which NTDC had used for the preparation of this IGCEP. Further, DAE used another alternate software namely BALMOREL which is an open source software and the above mentioned experts/consultants are adequately satisfied with the methodology that NTDC has deployed for the preparation of IGCEP. The only observation which Wartsila gave was that with the induction of the Run of River projects of Sukhi Kinari, CASA and Dasu etc., the HPP(s) are providing Seven (07) GW flexibility to the grid with two (02) daily peaks, which may be unrealistic. On the said, NTDC has submitted that it is more of an operational issue than a planning one therefore, the same may be considered in the next iteration. The DAE using BALMOREL which is an open source software, has confirmed the accuracy of the results of the IGCEP which NTDC has prepared.

(E). Observations/Directions of the Authority

(i). The Authority considers that NTDC has put up a great effort to prepare the IGCEP-2021-30 and the subsequent iterations for IGCEP-2022-31 using the indigenous manpower thus reducing reliance on the foreign experts/consultants. In this regard, the external experts which the Authority engaged for the review of the IGCEP-2022-31 have confirmed the NTDC has adopted the right methodology for the preparation of this vital planning document which will pave the way for the Least Cost of Energy addition in the country utilizing the indigenous resources.

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(ii). Further to the above, the Authority has certain observations to the submitted IGCEP-2022-31 including (a). delay in submission of the IGCEP contrary to provisions of the Grid Code; (b). changes in the approved set of assumptions including new ones for the preparation of the IGCEP-2022-31; (c). observations of the stakeholders regarding input of data different what they submitted; (d). dropping bagasse and indigenous coal based projects; (e). more emphasis on energy security; (f). complete absence of 100 MW block annually for new technologies including hybrid of wind/solar PV, waste to energy, Concentrated Solar Power (CSP), Power to X (P2X), Electricity Generation through Green Hydrogen and Solar PV with Battery Backup projects as proposed by relevant agency, which need to be addressed; (g). non-submission of complete TSEP; (h). impact of upcoming competitive market; (i). Demand Side Management (DSM) consideration; (j). studies for system reliabilities due to induction of more intermittent source of wind and solar; (k). sensitivity analysis due to delay in construction of HPP; (l). use of NCPI instead of CPI; (m). additional studies for system stability and reliability; and (n). submission of complete TSEP aligned to IGCEP horizon of ten (10) years with transmission cost included as per directions of the CCI to MoEPD.

(iii). In consideration of the above, the Authority directs NTDC to strictly adhere to the provisions of the Grid Code especially PC-4 and PC-4.1, which is applicable document and binding, thus submitting the next revised iteration of the IGCEP-23-32 within the given timeline without any exception before 30th June 2023 after consulting all stakeholders including the provinces/AJK and GB. The Authority may review/revise IGCEP anytime on its own or on the recommendation/request of any stockholder/province/AJK and GB. The Authority considers that output/results of IGCEP are directly linked with the provided input. The Authority has observed that for the IGCEP-2021-30, NTDC used the CCI approved assumptions which have been broadly maintained but there are a few differences as well. In order to avoid any confusion, the Authority directs NTDC to have the assumptions approved from it for the iteration of IGCEP-2023-32. The Authority has noticed that a few stakeholders had made the observations that NTDC used data for their respective project somewhat different to what was provided. In this regard, the Authority directs NTDC

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to be more transparent and apply more checks to avoid this situation/complaint. Further, the Authority also directs NTDC to have an undertaking/declaration from the executing agencies about the authenticity of the data and also from the energy department of the provinces/AJK and GB confirming that the consultation process has been done.

(iv). The Authority has observed that (a). NTDC has dropped indigenous bagasse based projects of about 450 MW proposed to be set up near the existing sugar mills all over the country while altering the CCI approved assumptions; (b). some projects with valid PPA(s) have not been considered whereas other(s) without PPA(s) are included in IGCEP that need to be aligned with CCI assumptions; (c). impact of floods need to be considered in future demand forecast; (d). higher fuel cost is considered in case of thermal plants dispatch and optimization, reference to be rationalized; and (e). impact of rising electricity price to be catered for.

(v). The Authority has observed that in the current IGCEP-2022-31, there is huge emphasis on utilizing indigenous resources and more than 77% of the installed capacity will be based on the said sources. The Authority considers that in the changing global dynamics there is a need to even further increase the use of indigenous resources of energy and same are made on priority. NTDC while preparing the plan has duly considered the same in its sensitivity analysis by considering C-5 project of 1200 MW in 2029 and 2x1320 MW Local coal projects in 2027 & 2030 respectively. The Authority directs NTDC to further review the said proposition and provide a scenario including both the C-5 and 2 x 1320 MW local coal projects in the next iteration.

(vi). The Authority has observed that there is serious issue of municipal waste in the country which is causing multiple problems of health and environment. One of the most efficient use of this solid waste is to use it for electricity generation as it has very good calorific value but no W_tE projects have been considered in the submitted IGCEP due to non-provision of data and other related information from the relevant agencies. The Authority directs NTDC to liaison with the relevant provincial and federal agencies and get the required information to have a suitable quota for

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WtE projects and other emerging new technologies including hybrid of wind/solar PV, Concentrated Solar Power (CSP), Power to X (P2X), Electricity Generation through Green Hydrogen and Solar PV with Battery Backup projects as proposed by relevant agency or any other related technology. The Authority further directs NTDC to consult all the relevant stakeholders and come up with a proposal for inclusion of suitable block of capacity on the said technologies.

(vii). The Authority considers that in order to have Least Cost Generation, it is imperative that IGCEP and TSEP are submitted simultaneously to have proper and a fair estimate of the end consumer cost of a project. In this regard, CCI while approving the assumptions for the first iteration of IGCEP-201-30 had directed MoEPD for the development of a criteria to factoring in the cost of transmission as part of the Least Cost Generation calculations in consultation with the provinces within three (03) months from September 13, 2021 which is still awaited. The Authority directs NTDC to coordinate with MoEPD and the provincial Govt. to expedite the formulation of the required criteria on top priority basis. Further, the Authority directs NTDC to ensure submitting complete TSEP with the next iteration of IGCEP-23-32 without any exception or delay as per the timeline prescribed in the Grid Code.

(viii). The Authority has noted that NTDC has not considered impact of upcoming competitive market on the demand which is going to be in operation maximum by April 30, 2023 as the required moratorium will automatically be lifted. The Authority considers that NTDC must liaison with the CPPA-G to have a fair estimate of the potential defection of the demand due to competitive market and accordingly make provision for the same for the next iteration. The Authority expresses its concern that there is very less emphasis on the DSM which is also very critical. The Authority directs NTDC to have a close liaison with all the relevant agencies to have updated estimates of the DSM for incorporating in the IGCEP-2023-32. The Authority has observed that there is great emphasis on the induction VRE of wind and solar being cost effective. Due to intermittent nature of said resources, there will be potential issues of system reliability and stability for which required studies may also be carried out. Additional sensitivity analysis to the extent possible also be

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carried out for the delay occurring due to construction of HPP especially in the public Sector. The Authority has observed the use of CPI which has now stand replaced with NCPI and the same will be used in the next iteration. The Authority observed that its appointed consultants/experts have pointed out that in IGCEP-2022-31 the hydro plants are providing Seven (07) GW flexibility to the grid with the induction of the Run of River projects of Sukhi Kinari, CASA and Dasu etc., with two (02) daily peaks which may be unrealistic. The Authority directs NTDC to initiate the process of such studies on priority so that the process of system planning becomes more refined and pragmatic.

(F). Approval of the Authority

(i). In light of the above, the Authority hereby approve the IGCEP-2022-31 in line with the relevant provisions of the applicable Grid Code and based on above observations.

(ii). The approved IGCEP-2022-31 along with all the relevant annexure including the comments of the stakeholders is attached herewith with this determination of the Authority.

Authority

Engr. Maqsood Anwar Khan
(Member)

Engr. Rafique Ahmed Shaikh
(Member)

Mathar Niaz Rana (nsc)
(Member)

01/02/23

Engr. Tauseef H. Farooqi
(Chairman)

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I reitrate my opinion on the optimized projects in 2021-30.

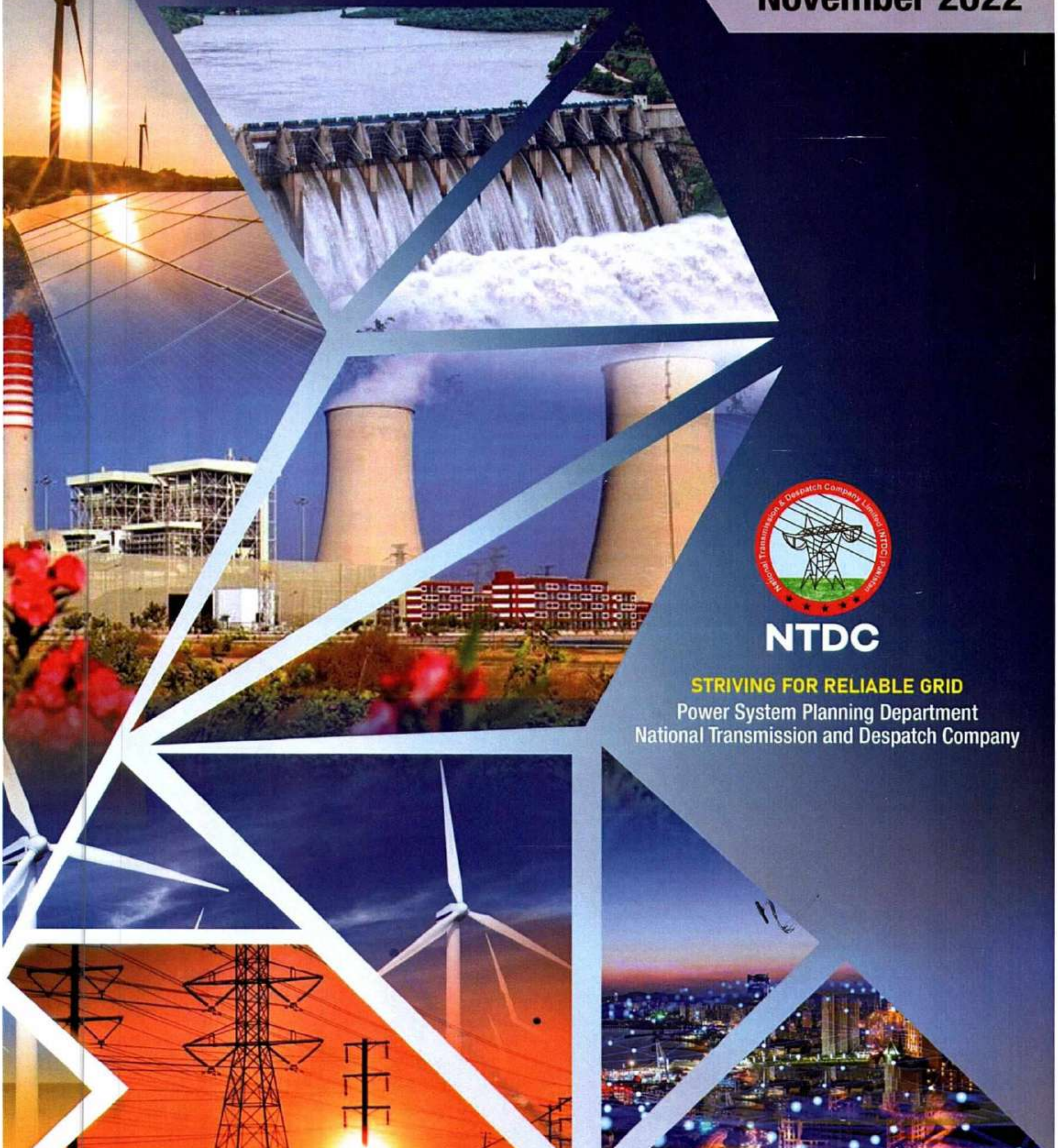
Annex-I

Approved

IGCEP 2022-31

Indicative Generation Capacity Expansion Plan (IGCEP) 2022-31

November 2022



NTDC

STRIVING FOR RELIABLE GRID

Power System Planning Department

National Transmission and Despatch Company

Indicative Generation Capacity Expansion Plan

IGCEP 2022-31

November 2022

Striving for Reliable Grid

Power System Planning Department
National Transmission and Despatch Company

Acknowledgements

The preparation of a country wide generation plan, such as the IGCEP, rely extensively on the input data provided by a wide range of entities. In case of IGCEP 2022-31, these entities include Pakistan Atomic Energy Commission (PAEC), State Bank of Pakistan, Finance Division–Economic Advisory Wing, 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), Power Planning and Monitoring Company (PPMC, former PEPCO), National Energy Efficiency and Conservation Authority (NEECA),Thar Coal and Energy Board (TCEB), K-Electric (KE), Water and Power Development Authority (WAPDA) and all DISCOs; this output could have not been materialized without the contribution by these entities.

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 Team is, therefore, highly grateful to all those who have contributed for the preparation, revision and finalization of the IGCEP 2022-31.

Disclaimer

a. This Indicative Generation Capacity Expansion Plan 2022-31 (the "IGCEP") has been prepared only as an indicative development plan for the period commencing on FY 2022 to FY 2031 (the "Plan"). It does not contain or determine targets or ascertain liabilities pertaining to power purchase or procurement, commissioning of future power projects, regulation or determination of electricity tariff, performance or ascertainment of economic dispatch etc. and is merely a suggested guide subject to finalization as per approval of the competent authority according to applicable law, policy and procedure.

b. The IGCEP has been prepared as per Planning Code (PC-4) of the prevailing Grid Code, based on proprietary input data as received from various power sector entities. In order to prepare the IGCEP, reliance is also placed on reference data and bench mark practices of international power sector entities for preparing similar plans, tariff determinations by NEPRA etc. Use of the IGCEP and / or any portion or variation thereof shall be at the sole discretion and risk of the user parties. NTDC shall not be held responsible in any manner whatsoever for the integrity, accuracy, inaccuracy, authenticity, correctness or representation of such data or consequences resulting therefrom. NTDC makes no representation or warranty of any kind, either express or implied, statutory or otherwise, including the accuracy or completeness of any data, reports, records, projections, information, or materials made available under the IGCEP and the transactions contemplated as consequence thereof.

c. The optimization of any generation project under Section 6.4 of the IGCEP shall not confer any right or any privilege or any confirmation of the generation project in question in relation to its implementation or execution. As highlighted, the IGCEP is an indicative development plan and confirmation of any new generation project for future procurement shall be subject to approval of respective competent authority as per applicable criteria prescribed in prevailing policies, rules and regulations.

d. The IGCEP is exclusive of any costs relating to power system evacuation and transmission system expansion for optimized generation project. The transmission system expansion and related costs shall be allocated to the optimized generation project following the approval of the transmission system expansion cost allocation criteria by CCI. This may impact the selection / optimization or ranking of the optimized generation project for which NTDC shall in no circumstances be held liable or accountable.

e. Any user or third party relying on the IGCEP or the Plan in any way shall do so at their own commercial, financial and legal risks for which they are encouraged to seek independent legal advice. NTDC makes no representation or warranty, express or implied, statutory or otherwise in relation to the information provided herein and its suitability for any project. NTDC expressly disclaims any and all responsibilities or liability whatsoever for loss or damages that may result from use of the IGCEP or portions or variations thereof and all users and the parties including affiliates and third parties hereby expressly acknowledge and agree to waive any and all recourse against NTDC and hold it harmless for their reliance upon the IGCEP i.e., the Plan including any intended or unintended consequences.

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List of Acronyms

Acronym	Description
$/GJ	US Dollar per Giga joule
$/kW	US Dollar per kilowatt
$/MWh	US Dollar per Megawatt hour
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 Technical & Commercial
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
c/Gcal	Cents per Giga calorie
c/kWh	Cents per kilowatt hour
ckm	Circuit kilometre
CAGR	Compound Annual Growth Rate
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 Administration
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

Acronym	Description
FS	Feasibility Studies
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 Pakhtunkhwa
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

Acronym	Description
LOI	Letter of Intent
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
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
MTPA	Million Ton Per Annum
MVA	Mega volt ampere
MW	Megawatt
MW_p	Megawatt Peak
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
NPV	Net Present Value
NTDC	National Transmission and Despatch Company
O&M	Operation and Maintenance
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
PPMC	Planning Power and Monitoring Cell
PSP	Power System Planning, NTDC
PV	Photo Voltaic has
QESCO	Quetta Electric Supply Company
RE	Renewable Energy
RFO	Residual Furnace Oil
RLNG	Re-gasified Liquid Natural Gas

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Acronym	Description
ROR	Run of the river
RP	Resource Planning
Rs./kWh	Rupees per kilowatt hour
SCADA	Supervisory Control & Data Acquisition
SEPCO	Sukkur Electric Power Company
SS	System Studies
SSRL	Sino Sindh Resources Limited
STs	Steam Turbines
T&D	Transmission and Distribution
TEL	Thar Energy Limited
TESCO	Tribal Electric Supply Company
TP	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/

Stakeholder Entities	Cyber Link
K-Electric (KE)	https://www.ke.com.pk/
Lahore Electric Supply Company (LESCO)	http://www.lesco.gov.pk/
Multan Electric Power Company (MEPCO)	http://www.mepco.com.pk/
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/
Power Planning and Monitoring Cell	https://www.pepcopakistan.com
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/
Thar Coal and Energy Board	http://www.tceb.gos.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) 2022-31" presents the results of the latest generation expansion planning study conducted by the Power System Planning (PSP) Department of National Transmission and Despatch Company (NTDC) for the entire bulk power system, as per the criteria specified in prevailing Grid Code, National Electricity Policy (NEP) 2021 and specified assumptions.

This report provides a comprehensive view of grid-connected electricity demand, forecasted until 2031, and the generators optimized from the stock of existing, committed and candidate power plants to meet that demand in a cost-effective manner while ensuring system adequacy. Annual revision of this plan remains a regulatory obligation on the part of the NTDC.

Ensuring system adequacy, reliability and affordability has been a challenge for the System Operator in 2022. High fuel prices and fuel shortages were compounded by an unusually high demand for electricity in April. While the Base Case is the least cost solution, the Sensitivity Scenarios provide alternatives for increased energy security, which is an important consideration in the context of climate change and the high cost of imported fuels.

I commend the Load Forecasting and Generation Planning for preparing the IGCEP 2022-31, in view of their enthusiastic willingness to learn and contribute in the best interests of NTDC and Pakistan, I envisage this team will continue to develop its expertise, engage with stakeholders and provide outputs at par with international standards.

Deputy Managing Director (System Operation)
National Transmission and Despatch Company

Executive Summary

Pursuant to the provisions of the National Electric Power Regulatory Authority (NEPRA) prevailing Grid Code i.e., Planning Code PC 4 and PC 4.1, NTDC has prepared IGCEP 2022-31 covering 10 years' time frame from 2021-22 to 2030-31 encapsulating power generation additions required to meet the future energy and power demand of the country including NTDC and KE systems.

The report presents the results of the generation capacity expansion planning study which 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 software programs.

Three scenarios of long-term forecast, as per prevailing Grid Code, are prepared for the Low, Normal and High GDP growth of 3.40%, 4.30% and 5.42% respectively.

Table E1 shows a summary of the forecast results for the horizon 2022-2031.

Table E1: Summary of Load Forecast (2022-31)

FY	Low		Normal		High	
	Energy	Peak Demand	Energy	Peak Demand	Energy	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2021-22*	153,866	26,945	153,866	26,945	153,866	26,945
2022-23	155,919	28,351	156,379	28,436	156,904	28,532
2023-24	163,166	28,836	164,394	29,054	165,840	29,310
2024-25	169,733	30,168	172,056	30,583	174,841	31,081
2025-26	176,681	31,440	180,396	32,105	184,897	32,909
2026-27	183,271	32,722	188,651	33,688	195,241	34,865
2027-28	190,366	34,120	197,651	35,430	206,693	37,053
2028-29	197,288	35,489	206,693	37,191	218,524	39,321
2029-30	204,729	36,955	216,444	39,086	231,394	41,786
2030-31	214,233	38,744	228,505	41,338	246,925	44,668
CAGR (2022-2031)	3.75%	4.12%	4.49%	4.87%	5.40%	5.78%

**Actual figures*

The least cost, long-term generation expansion plan for the power system of country is developed using state-of-the-art generation planning software - PLEXOS. The IGCEP 2022-31 is developed through a rigorous data modelling and optimization exercise based on the existing and future generation power projects, existing policy framework, existing contractual obligations, natural resource allocations, relevant provisions of prevailing Grid Code, and assumptions laid down in National Electricity Policy 2021 (NEP) along with some additional assumptions.

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The base case scenario is developed on normal scenario of long-term forecast, existing contractual obligations and retirements of power projects, during the planning horizon of the IGCEP, as per terms of their respective Power Purchase Agreement (PPA), except KAPCO.

For the study, 8,021 MW of existing power generation capacity is retired during the plan horizon, in every scenario.

For the purpose of sensitivity analysis, six (6) scenarios are developed, in addition to the base case scenario, which include i) Low Demand Scenario; ii) High Demand Scenario iii) Diamer Bhasha HPP in 2029; iv) Chashma Nuclear (C-5) for Energy Security; v) Local coal inclusion in 2027 and 2030 and vi) Unconstrained VRE Scenario.

Hourly demand forecast is developed specially to cater for the intermittency of variable renewable energy resources such as wind and solar PV. This is particularly important in view of the aggressive targets pertaining to renewable energy envisioned by the Government of Pakistan. Hence, the energy and peak demand forecast of 87,600 hours have been estimated from the year 2021-22 to 2030-31.

In the base case, the demand and installed capacity of the whole country is 41,338 MW and 68,667 MW, respectively by the year 2031. It is to highlight that in the said installed capacity, the optimized share from variable renewable energy (VRE) resources include 8,564 MW_p of Solar PV (utility solar & feeder based/DG) and 4,827 MW of Wind. Apart from VREs, 3,5 MW and 990 MW of hydro and local coal is optimized by the tool, respectively. It is to add here that the optimized local coal can be installed in any of the three blocks of Thar i.e., Block-I, II & VI, based on the assumption that the price at all three blocks of Thar will be same. It is added that 3,330 MW_p net metering solar is also added in the NTDC system i.e., 370 MW_p, every year.

Consequently, salient features of the base case include: i) aggressive inclusion of VREs; ii) Minimal reliance on imported fuels i.e., Coal, RLNG and Residual Furnace Oil (RFO) based technologies, iii) increased share of hydropower as well as local coal, and iv) All optimized generation is based on Indigenous resources. Inclusion of VREs, hydro and local coal will help in lowering the basket price of the overall system thus providing much needed relief to the end consumers, though in the long run.

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Table E2: Scenario-wise Installed Capacity (MW) by 2030-31

Category	Base	Low Demand	High Demand	Diamer Bhasha HPP in 2029	Chashma Nuclear (C-5) for Energy Security	Local Coal inclusion in 2027 & 2030	Un-constrained VRE
Imported Coal	4,680	4,680	5,340	4,680	4,680	4,680	4,680
Local Coal	4,590	4,590	5,580	4,590	4,590	7,230	4,590
RLNG	8,710	8,710	8,710	8,710	8,710	8,710	8,710
Gas	1,933	1,933	1,933	1,933	1,933	1,933	1,933
Nuclear	3,620	3,620	3,620	3,620	4,820	3,620	3,620
Bagasse	394	394	394	394	394	394	394
Solar PV*	12,926	10,262	13,504	12,606	12,732	10,532	12,115
HPP	22,701	22,403	23,041	26,871	22,403	22,403	22,701
Cross Border	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Wind	6,767	5,693	8,817	5,814	6,885	5,836	7,508
RFO	1,347	1,347	1,347	1,347	1,347	1,347	1,347
Total (MW)	**68,667**	**64,631**	**73,285**	**71,565**	**69,493**	**67,684**	**68,597**

**Solar values are in MW_p*

The Annexures in the report present the detailed results of all the scenarios and sensitivity studies conducted. The results show a shift in the energy mix (GWh) from imported fuel to indigenous ones, i.e., local coal and dominating share of renewables and hydropower. The base case shows a major contribution from renewables, i.e., 41% of hydropower and 20% of variable renewable energy in the overall energy mix by the year 2031. There is minimal reliance on the imported fuels with RFO having no contribution at all in the energy mix, whereas imported coal and RLNG is contributing just 8% (due to contractual binding) and 2% in the total energy requirements, respectively. The share of indigenous fuels stands 29%, i.e., 13% of local coal, 5% of local gas and 11% of nuclear in the overall energy mix.

It is pertinent to mention that the tool assures sufficient firm/base capacity in the form of hydel (existing, committed & optimized), RLNG (existing & committed), local coal (existing, committed & optimized), imported coal (existing & committed) and nuclear based (existing) power projects is available 24/7 in the system till the end of study horizon to meet the given hourly system demand whilst catering for REs intermittency and system reserve requirements.

Furthermore, the present volume of solar PV and wind power project considered as candidate is subject to change, based on the outcome of operational/stability studies to be conducted in future, in order to determine the optimum quantum of solar PV and wind sources that can be integrated in National Grid. The same will be considered in the next iteration of IGCEP.

PLEXOS tool also computes Net Present Value (NPV) of the power generation operations and investments of existing and future power projects by 2031 based on the objective function for the optimization exercise. Table E3 shows the total NPV required to manage generation infrastructure construction, operations and maintenance by 2031 separately for all scenarios. The base case scenario indicates 52.99 billion US$ NPV investment requirements both in terms of CAPEX and OPEX of electric power generation by the year 2031.

Table E3: Total Cost Comparison of all Scenarios in Billion US $

#	Scenario	Total Cost (Billion US $)
1.	Base Case	52.99
2.	Low Demand	51.20
3.	High Demand	55.45
4.	Diamer Bhasha HPP in 2029	53.82
5.	Chashma Nuclear (C-5) for Energy Security	53.32
6.	Local Coal inclusion in 2027 & 2030	53.18
7.	Unconstrained VRE Scenario	52.30

The generation planning exercise demands extensive data, i.e., both validated and verified. Strenuous efforts are needed to streamline access to data for future exercises pertaining to forecasting, generation capacity expansion and despatch optimization. In addition to access to the available data, provision of certain key targets is essential for the updation of the IGCEP that includes demand side management, net-metering, distributed generation etc.

The IGCEP 2031 also facilitates structural changes in the power sector planning process with enhanced role of distributed generation and reduction in the large projects distant from the load centers. Further, indigenization of RE technologies through local manufacturing is also suggested to lower the basket price, for provision of relief to the end consumer as well as saving precious foreign exchange while maximizing the nature's endowment bestowed upon Pakistan.

In view of the results stated above, the following conditions are proposed herewith for all the candidate projects being optimized in IGCEP 2022-31:

a. The cost nos (CAPEX & OPEX) approved by NEPRA for an optimized project shall either be equal or less than the cost used in IGCEP, if in any case the cost given by NEPRA to any optimized project is more than the one used in IGCEP, then a re-run shall be required to assess the viability / optimization of that very project on the new cost.

b. For issuance of LOS to the private sector projects and PC-1 approval of the public sector projects, the relevant agency must ensure that the project cost determined/approved by NEPRA shall either be less than or equal to the cost considered in IGCEP for that particular optimized project, otherwise, re-evaluation of the project on the basis of new cost shall be done.

In addition to above, it is re-iterated that the selection of any generation project in IGCEP does not ensure any guarantee to execute that project which shall have to undergo approvals from all the relevant government authorities.

1. SETTING THE PERSPECTIVE

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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 projects over the long-term horizon – 10 years for IGCEP 2022-31. 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 ideal 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 National 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 minimize the generation costs while ensuring adequate generation capacity is added to meet the hourly forecasted demand.

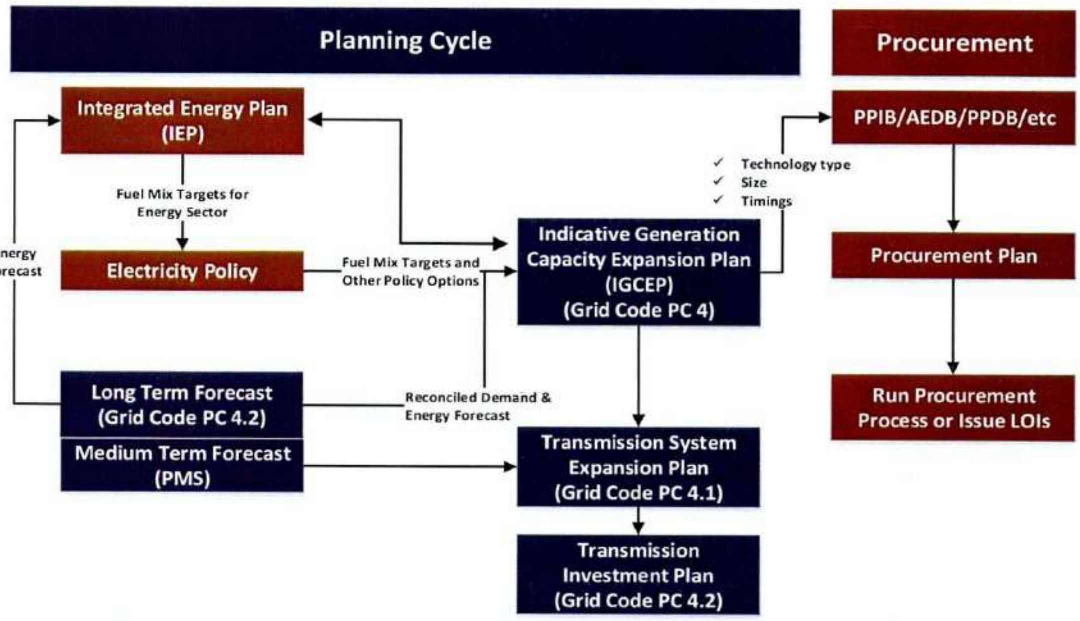

Figure 1-1: Planning Cycle Leading to Procurement

1.2. Preamble

Taking a glimpse at the relevant previous milestones, following six (06) 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)
d) Indicative Generation Capacity Expansion Plan (IGCEP 2018-40)
e) Indicative Generation Capacity Expansion Plan (IGCEP 2020-47)
f) Indicative Generation Capacity Expansion Plan (IGCEP 2021-30)

This latest iteration of IGCEP 2022-31 has been developed based on the relevant provisions of prevailing Grid Code, and assumptions laid down in National Electricity Policy 2021 (NEP) along with some additional assumptions, using generation capacity expansion planning tool i.e., PLEXOS, by considering all the existing, committed and candidate power projects.

It is worth mentioning here that the last three (03) versions of IGCEP were developed for NTDC system only with a fixed quantum (MW) of export to K-Electric, however, pursuant to National Electricity Policy 2021, NTDC is responsible for power system planning of the whole country. In this regard, this iteration of IGCEP comprises of NTDC and K-Electric systems connected with a tie line having a fixed export of 1,100 MW till June 2024 and 2,050 MW till the end of study horizon. Moreover, expansion of candidate power projects has been opened both in NTDC and K-Electric system, thus covering the whole country.

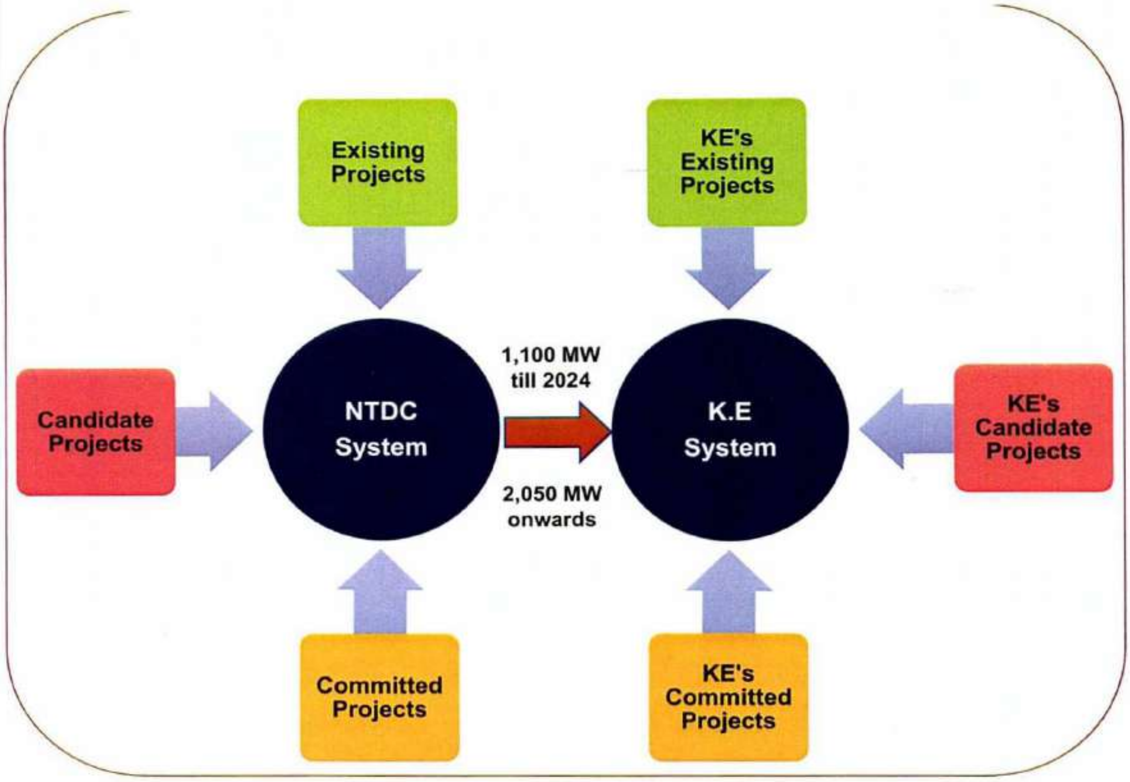

Figure 1-2: IGCEP System (NTDC + K-Electric)

1.3. Introduction

Energy access is an essential requirement of modern society. 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 unique, since it cannot be stored, at least not in large quantities. Power generation and consumption must equate in real time. Additional factors such as seasonal variations make the demand forecast process quite complicated. On the other hand, insufficient or even surplus generation capacity adversely affects the economy. Long-term generation planning is therefore, a complex task, which involves the commitment of large resources, for the power sector and the economy as a whole.

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 prevailing 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, updated generation commitment schedule and other parameters.

Figure 1-3: The IGCEP Objectives

1.4. Objectives of the IGCEP

The IGCEP is envisioned to meet the following objectives, as highlighted in the Figure 1-3:

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 prevailing Grid Code: PC - 4.1;
c. **Cater** for the long-term load growth forecast and reserve requirements pursuant to the prevailing 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 2030-31.

1.5. Scope and Planning Horizon

The IGCEP covers the whole country including 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 2022-31 includes an export of 1,100 MW from NTDC system to K-Electric up to June 2024, 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 2021-22 to 2030-31.

1.6. Purpose 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 generation planning tool i.e., PLEXOS[1] includes consideration of hourly projected electric power demand up to the year 2030-31 and various other characteristics such as hydrology of hydro power projects, fuel costs estimations and all technical and financial data pertaining to existing and potential generation options i.e., hydro power, thermal and renewables, and optimization of all options. The IGCEP is the starting point for the Transmission System Expansion Plan which is the next step in the PSP process.

The IGCEP should 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 prevailing 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.

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

[1] https://www.energyexemplar.com/plexos

hydro power projects. 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.

1.8. Generation Capacity Expansion Software

For preparation of the IGCEP, PLEXOS package has been utilized. The objective function seeks to minimize the net present value of build costs plus fixed operations and maintenance costs plus production costs. The core formulation for LT Plan by PLEXOS is thus:

Minimize

- $\sum_y \sum_g DF_y(BuildCost_g * GenBuild_{g,y}) + \sum_y DF_y [FOMCharge_g * 1000 * Pmax_g (Units_g + \sum_{i \le y} GenBuild_{g,i})] + \sum_t DF_{t \in y}\ L_t [VOLL * USE_t + \sum_g (SRMC_g * GenLoad_{g,t})]$

Subject to constraints:

Equation 1: Energy Balance

$$\sum_g GenLoad_{g,t} + USE_t = Demand_t\ \forall t$$

Equation 2: Feasible Energy Dispatch

$$\sum_g GenLoad_{g,t} \le PMAX_g \left(Units_g + \sum_{i \le y} GenBuild_{g,i} \right)$$

Equation 3: Feasible Builds

$$\sum_{i \le y} GenBuild_{g,i} \le \mathrm{MaxUnitsBuilt}_{g,y}$$

Element	Description	Unit
GenBuild (g,y)	Number of generating units build in year y for Generator g	integer
GenLoad(g,t)	Dispatch level of generating unit g in period t	continuous
USE_t	Unserved energy in dispatch period t	continuous
$CapShort_y$	Capacity shortage in year y	continuous
D	Discount rate. We then derive $DF_y = \frac{1}{(1+D)^y}$ which is the discount factor applied to year, and DF t which is the discount factor applied to dispatch period t	
L_t	Duration of dispatch period t	Hours
$BuildCost_g$	Overnight build cost of generator g	$

$MaxUnitsBuilt_{(g,y)}$	Maximum number of units of generator g allowed to be built by the end of year y	
$PMAX_g$	Maximum generating capacity of each unit of generator g	MW
$Units_g$	Number of installed generating units of generator g	
VoLL	Value of lost load (energy shortage price)	\$/MWh
$SRMC_g$	Short-run marginal cost of generator g which is composed of Heat Rate × Fuel Price + VO&M Charge	\$/MWh
$FOMCharge_g$	Fixed operations and maintenance charge of generator g	\$
$Load_t$	Average power demand in dispatch period t	MW
$PeakLoad_y$	System peak power demand in year y	MW
$ReserveMargin_y$	Margin required over maximum power demand in year y	MW
CapShortPrice	Capacity shortage price	\$/MW

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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 of an indispensable infrastructure in any economy. The provision of 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 with 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 in all developing nations where GDP and sale of electricity have a direct relationship and growth in GDP causes increased sale of electricity.

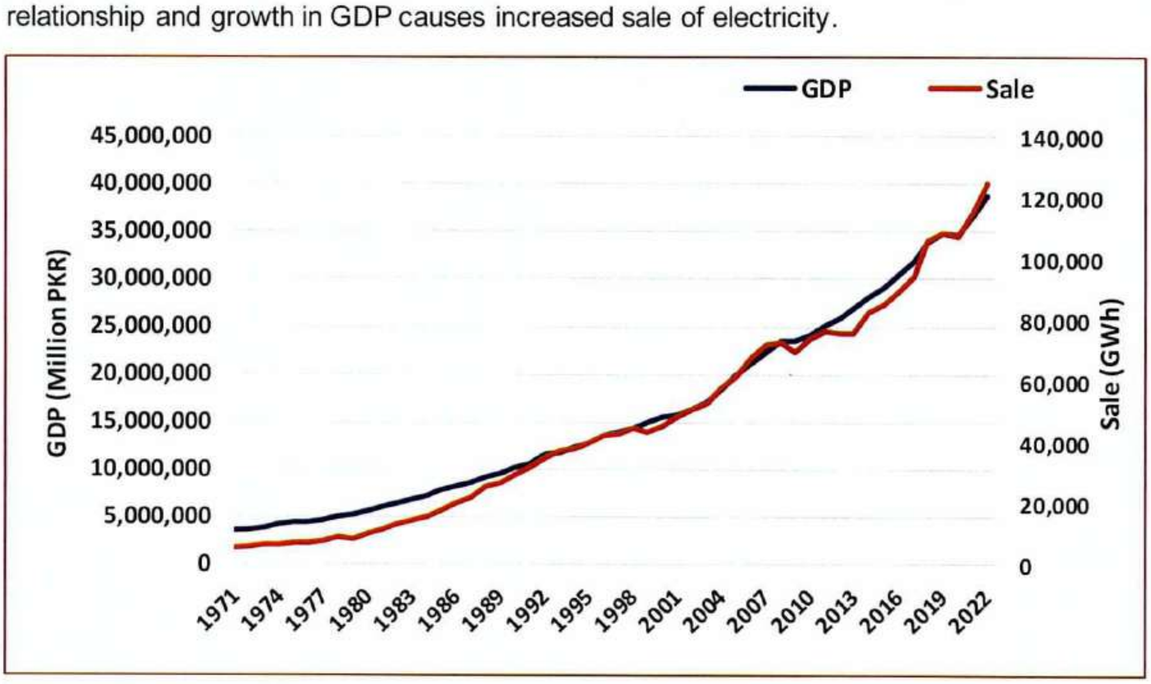

Chart 2-1: GDP (million PKR) vs Sale of Electricity (GWh)

During the fiscal year 2021-22, the country has seen 5.97% growth rate in total GDP (source: Economic Survey of Pakistan, whereas, the growth rates of 4.4%, 7.2% and 6.2% are observed in agriculture, industrial and commercial/services sectors, respectively. During the same period, 7.07% growth rate in generation of electricity has been observed. This increase in GDP as well as in usage of electricity shows strong association between GDP and electricity.

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2.2. Power Generation

As of June - 2022 the total installed generation capacity of NTDC system reached to 37,949 MW. Out of which 34% is RE share which comprises of hydro, solar PV, wind and bagasse-based technologies, and 66% share is from thermal projects comprising of local gas, local coal, imported coal, RFO, RLNG and nuclear based technologies, as shown in the Chart 2-2.

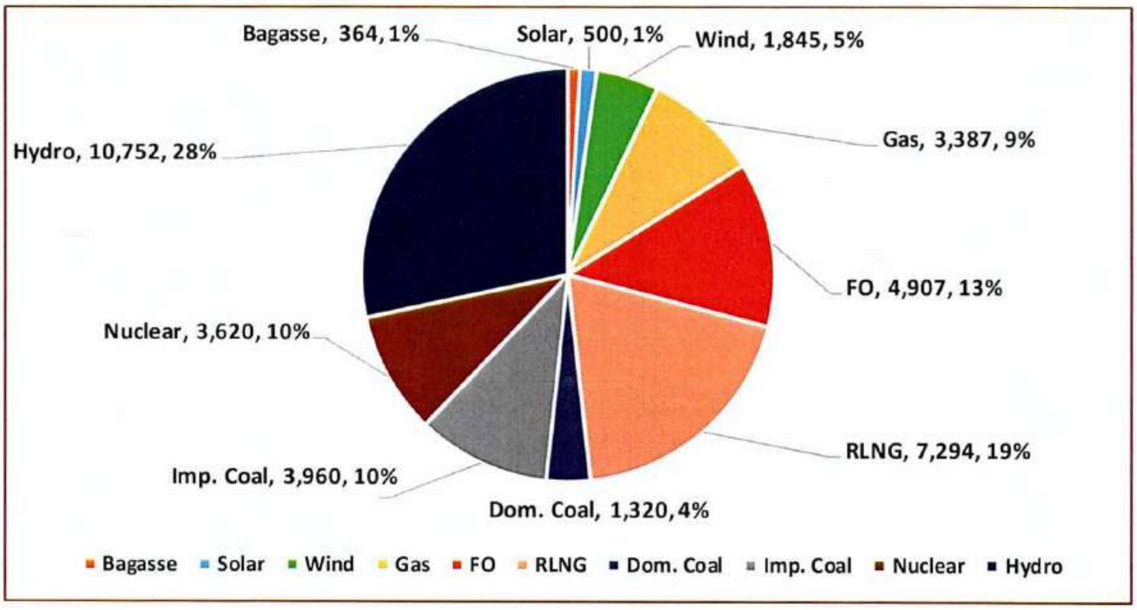

Chart 2-2: NTDC System Installed Capacity (MW)

The energy produced by NTDC system power generation fleet during the fiscal year 2021-22 was 143,017 GWh which was contributed approximately 25% by hydroelectric projects and 58% by thermal projects on local gas, local coal, imported coal, RFO and RLNG based technologies, 13% by nuclear projects, and 4% by renewable energy power projects which covers solar PV, wind and bagasse-based technologies as shown in the Chart 2-3.

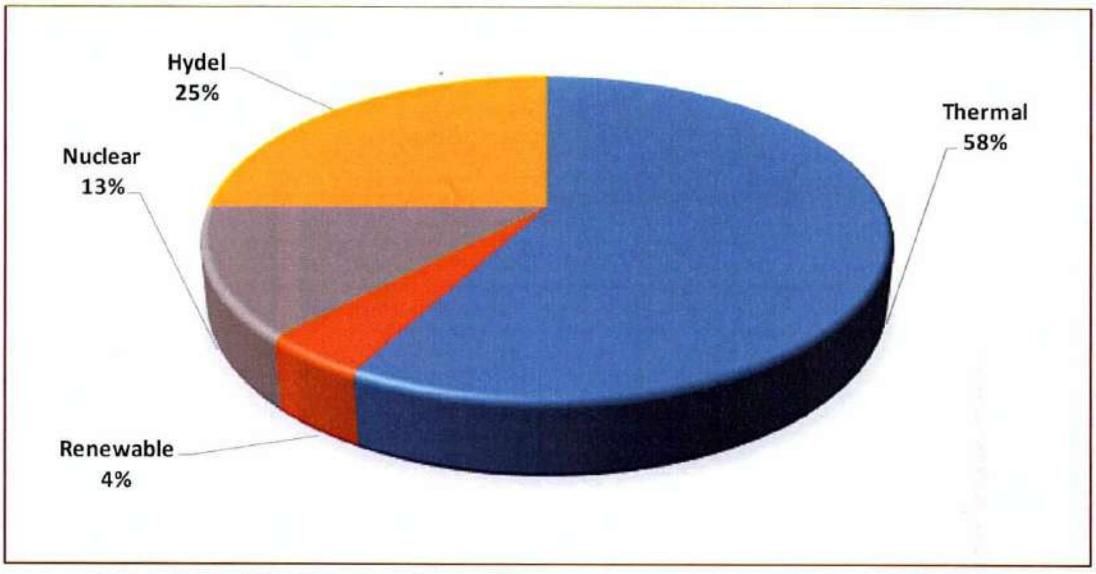

Chart 2-3: NTDC System Annual Energy Generation (GWh) as of 2021-22

Similarly, the total installed generation capacity of KE system reached to 3,319 MW, out of which 97% is thermal projects which comprising of local gas, local coal, imported coal, RFO and RLNG based technologies and 3% RE comprising of solar PV as shown in Chart 2-4.

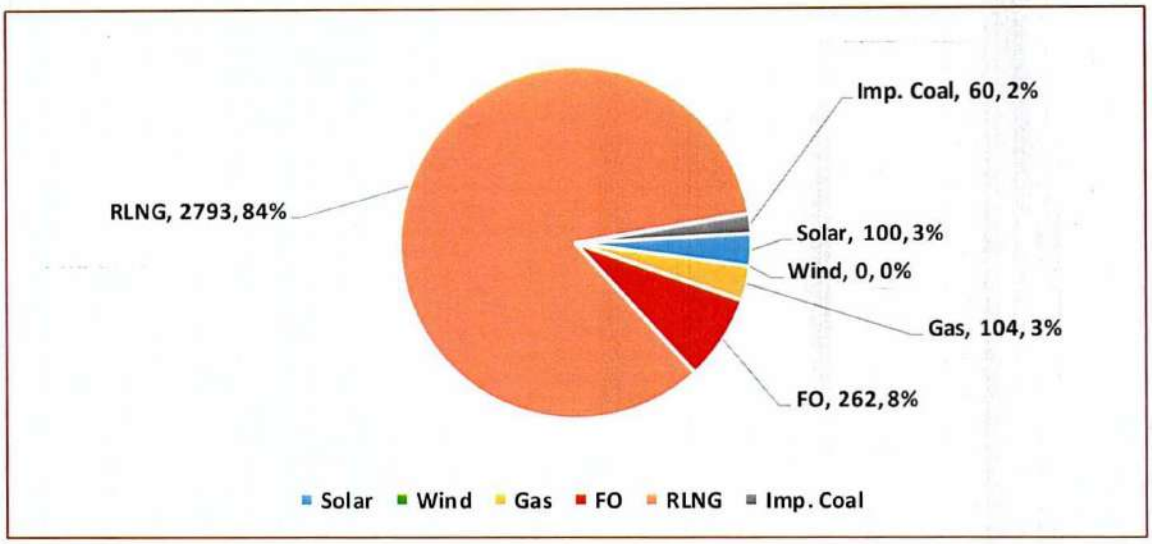

Chart 2-4: K-Electric System Installed Capacity (MW)

The energy produced by K-Electric system power generation fleet during the fiscal year 2021-22 was 10,861 GWh which was contributed primarily 96% by thermal projects on local gas, RFO, HSD, imported coal and RLNG based technologies, 1% by nuclear projects, 2% by solar PV and 1% by wind-based technology as shown in the Chart 2-5.

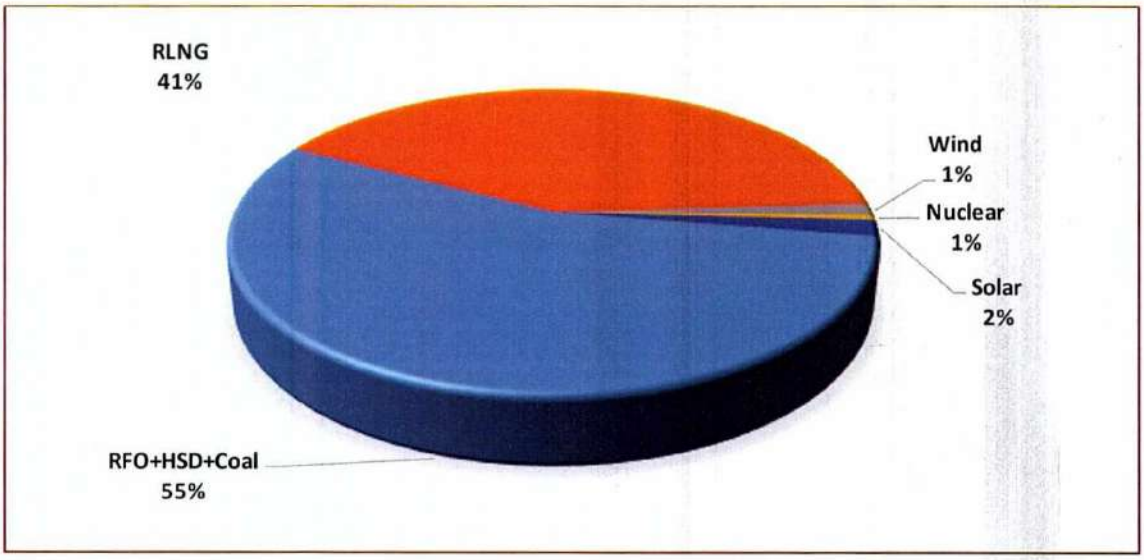

Chart 2-5: K-Electric System Energy Generation (GWh) as of 2021-2022

Furthermore, there has been an increasing trend in the electricity generation (GWh) statistics of the country from 2013-14 to 2018-19, however, a slight decrease is observed in the year 2019-20 due to lesser demand owing to struggling economy coupled with the impacts of COVID-19 pandemic. However, since 2020-21, the trend is again increasing as shown in the Chart 2-6.

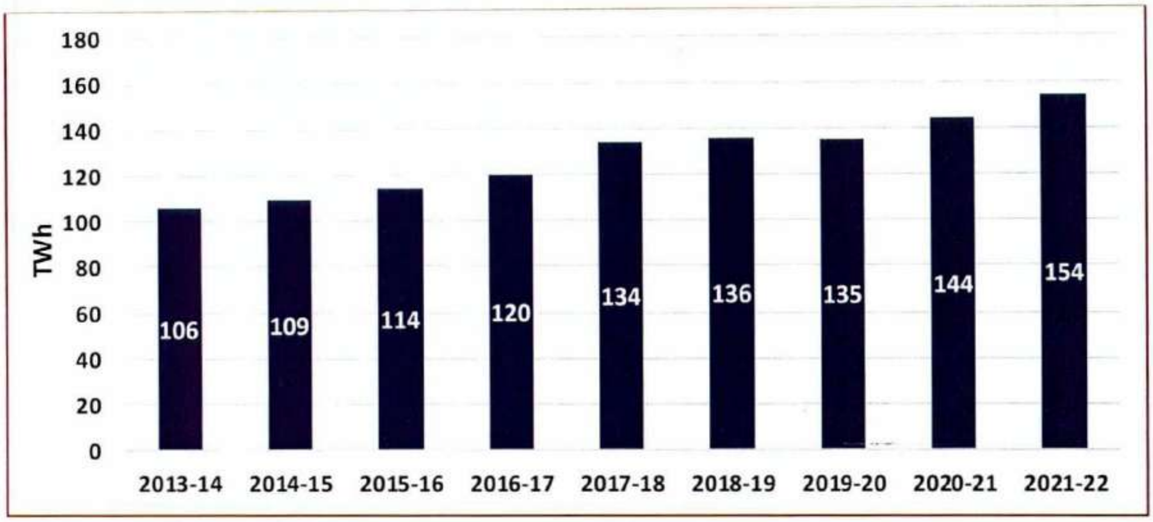

Chart 2-6: Historic Energy Generation (TWh) of country from 2013-14 to 2021-22

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 2-7.

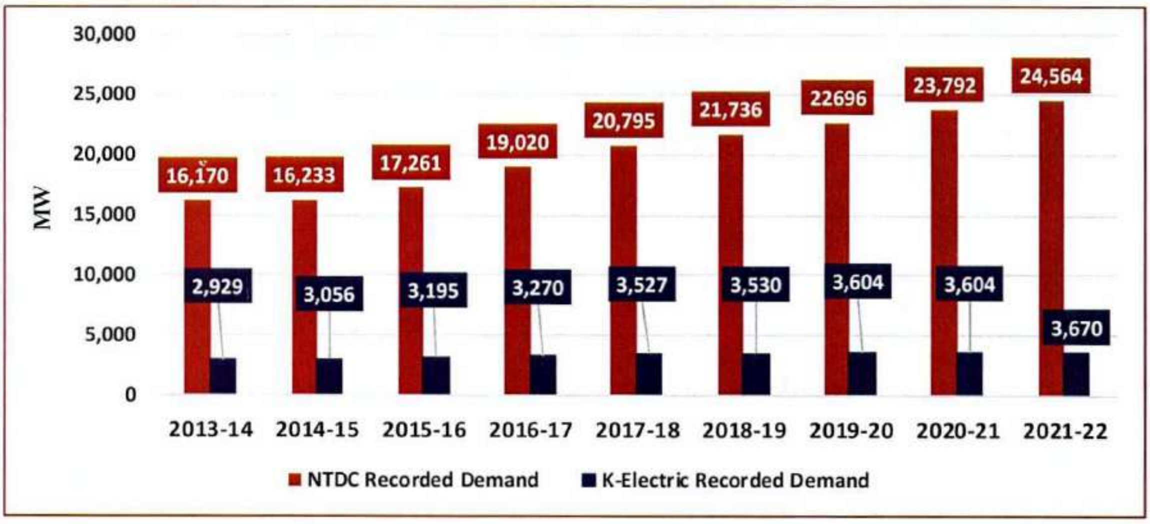

Chart 2-7: Historical Peak Electricity Demand (MW) from 2013-14 to 2021-22

Peak demand of NTDC (including export to K-Electric) and K-Electric during 2021-22 is 24,564 MW and 3,670 MW respectively.

2.3. Power Distribution

By the year 2021-22, total number of electricity consumers in the country have reached to 36,595,128 out of which 31,594,985 belong to domestic category, 3,984,802 belong to commercial category, 391,442 consumers fall under industries, 371,449 are agriculture consumers and other consumers are 252,450 as shown in Chart 2-8.

During the year 2021-22, total electricity consumption in country reached to 124,630 GWh, out of which domestic consumption had a share of 60,410 GWh, commercial consumption

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was 9,233 GWh, industrial consumption was 33,958 GWh, agriculture consumption was 11,033 GWh and 9,996 GWh had been consumed by other categories as shown in Chart 2-9.

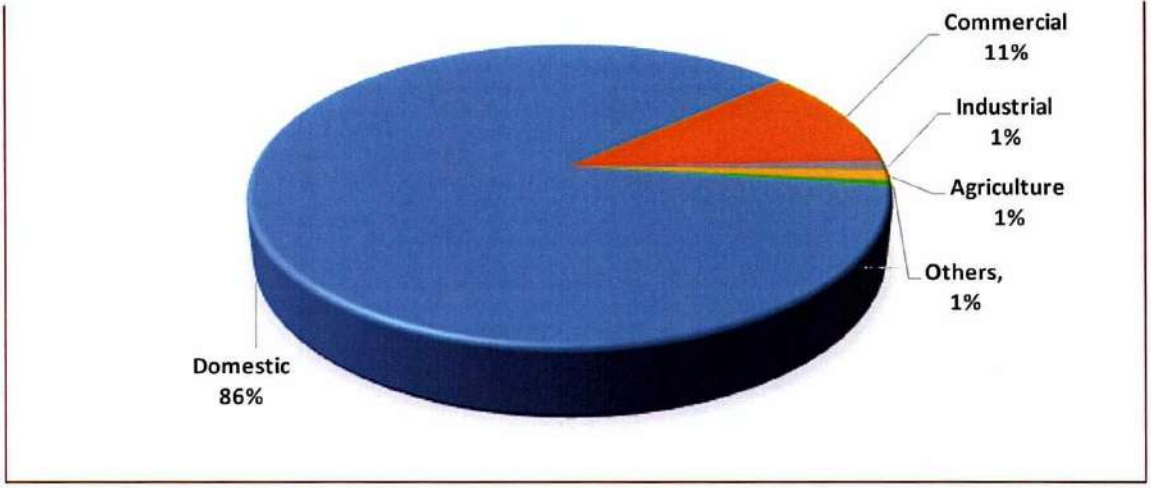

Chart 2-8: Percentage Mix of Number of Electricity Consumers

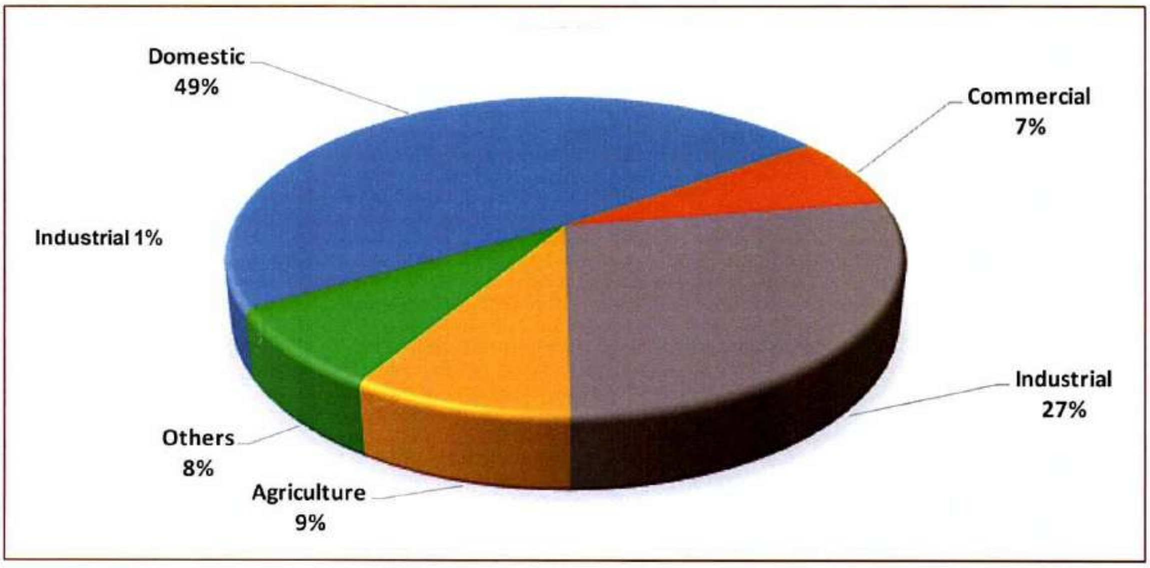

Chart 2-9: Percentage Mix of Category-wise Sale (GWh) of electricity

Electricity consumption in Pakistan is dominated by the domestic sector followed by industrial and agricultural sector as shown in Chart 2-9.

3. THE IGCEP METHODOLOGY

3. The IGCEP Methodology

3.1. Regulatory Compliance

Pursuant to the prevailing Grid Code, the IGCEP covers the future development of hydroelectric, thermal, nuclear and renewable energy resources to meet the anticipated load demand by the year 2030-31. It identifies new generation 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 prevailing 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 collection process for the purpose of this study was extremely 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 NTDC Forms (available at the web link https://diplanning.ntdc.com.pk/) for providing the requisite input data on the prescribed format, the same 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 projects from the concerned entities:

a. Specific data input formats were customized, involving suitable conversions, as per requirements of the generation capacity expansion planning 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. All the data received was precisely analyzed for accuracy and completeness, and gaps were identified and rectified / adjusted accordingly.

d. 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 have contributed for the preparation of input data to be used in IGCEP 2022-31:

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 projects under the jurisdiction of AJ&K

c. Azad Jammu Kashmir Private Power Cell (AJKPPC)
   - Existing and future hydro power projects 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 projects under the jurisdiction of the Sindh province

f. Finance Division (Economic Adviser's Wing)

- Sector wise GDP projections

g. GENCOs

- Existing and future thermal power projects in the public sector

h. K-Electric

- Hourly energy and demand forecast
- Existing and future projects data

i. 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

j. National Power Control Centre (NPCC)

- Monthly energy and MW capacities for the existing wind and solar PV power projects

k. Pakhtunkhwa Energy Development Organization (PEDO)

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

l. Pakistan Atomic Energy Commission (PAEC)

- Existing and future nuclear power projects

m. Pakistan Bureau of Statistics

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

n. Power Planning and Monitoring Company (PPMC)

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

o. Private Power Infrastructure Board (PPIB)

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

p. Punjab Power Development Board (PPDB)

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

q. Thar Coal and Energy Board (TCEB)
   - Block wise Thar Mine's cost and capacity
r. Water and Power Development Authority (WAPDA)
   - Existing and future hydro power projects to be developed by WAPDA
s. World Bank
   - GDP Projections

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 projects, cost data shared by the concerned project executing agencies, after indexation, have been used.

3.5. The IGCEP Preparation Process Map

The IGCEP is prepared after following the process illustrated through Figure 3-1 and is submitted to NEPRA for review and approval, following an extensive internal consultative process.

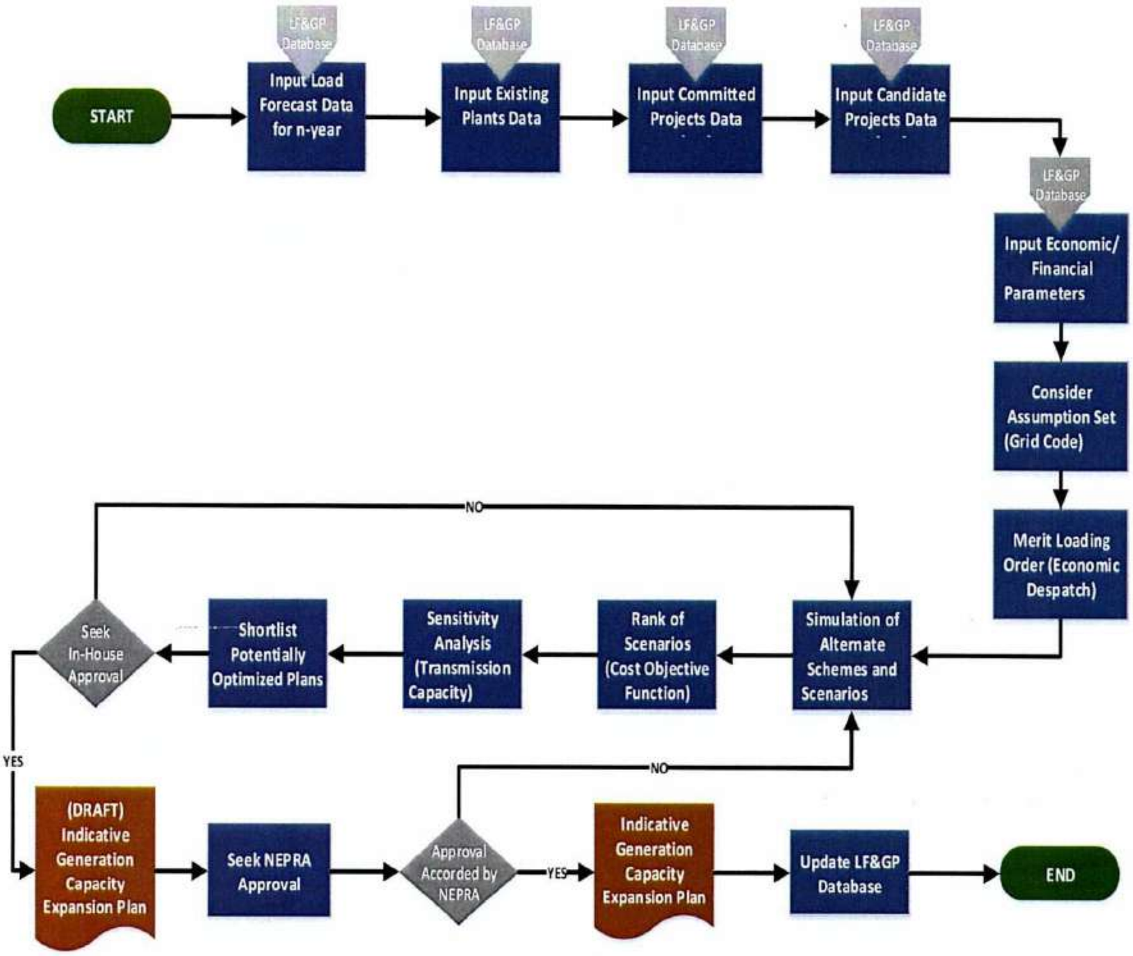

Figure 3-1: The IGCEP Preparation Process

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, 2021 to June 30, 2031.

3.6.2. Generation System Reliability

The capability of the generating system to meet the forecasted 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 projects.

Loss of Load Expectation (LOLE) in days or equivalently Loss of Load Probability (LOLP) in percentage 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 prevailing Grid Code, has been adopted.

3.6.3. Hydrological Risk

For the development of IGCEP, seasonal variation in hydro power plants has been considered. In this regrad, the average values of monthly energy and capacity for each respective power plant based on the feasibility study and as conveyed by the concerned project executing agencies, have been used to capture the seasonality factor in the output of hydroelectric projects.

3.6.4. Renewable Energy (RE) Generation

As of June 2022, 500 MW_p utility scale solar PV and 1,845 MW wind power on-grid projects, have been commissioned in NTDC system whereas 100 MW_p utility scale solar PV has been installed in K-Electric system.

Subsequent to Cabinet Committee on Energy (CCoE) decision of April 4, 2019 and June 16, 2020, RE projects, i.e., wind, solar PV, and bagasse (currently under litigation except Shahtaj) defined under Category-I & II, presently at different stages of development are envisaged to be added into the national grid during the next couple of years.

Based on the available data and after multiple rounds of discussions/deliberations with World Bank's engaged consultant i.e., M/s 8.2, AEDB and CPPA-G, capacity factors of 22.1%, 20%, 17%, 42% and 55% have been considered for candidate utility solar PV, feeder based (DG) solar, solar net metering, wind and bagasse-based power projects, respectively.

3.6.5. 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 prevailing Grid Code, i.e., contingency and secondary.

3.6.5.1. 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 the 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 (Karachi Nuclear K-2/K-3 being the largest thermal unit). Moreover, to cater for VRE intermittency, some additional reserve on top of 1,145 MW is added i.e., 2.9% and 5.3% of actual generation (MW) of solar PV and Wind, respectively as per best international practices (considered by M/s Lahmeyer Intl. in 'VRE Integration and Planning study for Pakistan').

3.6.5.2. 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 along with 2% of actual generation (MW) of solar PV and wind is considered throughout the planning horizon, to mitigate VRE intermittency.

3.6.6. 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 and hydro, will undergo an annual maintenance program as provided by the concerned project executing agency.

3.6.7. 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 2030-31. Normal scenario of the load forecast has been adopted as a base case in this study.

3.6.8. Fuel Prices Indexation

Pakistan's electricity generation mix relies heavily on fossil fuels including RLNG, imported / domestic coal, local gas and furnace oil, hence, fuel price uncertainty is one of the major determinants for a long-term generation expansion plan. In this regard, the base fuel prices have been taken as per latest Merit Order of June 2022. These fuel prices are then indexed for future years as per the Energy Information Administration (EIA) Annual Energy Outlook 2022 (except for domestic coal & bagasse where Thar Coal & Energy Board tariff was applied to domestic coal and upfront tariff of bagasse in 2017 was applied to bagasse). The variable price index for each of the fuel-based technologies is given in Table 3-1.

Table 3-1: Fuel Price Indexation Factors

Year	Furnace Oil	Local Gas / RLNG	Imported Coal	Uranium	Thar Coal	Bagasse
Variable Price Index for Fuel Based Technologies						
2021-22	1.000	1.000	1.000	1.000	1.000	1.00
2022-23	0.961	0.936	0.992	1.003	1.001	1.00
2023-24	1.029	0.862	0.991	1.004	0.994	1.02
2024-25	1.044	0.820	0.967	1.007	1.009	1.02
2025-26	1.057	0.819	0.951	1.009	0.937	1.04
2026-27	1.089	0.841	0.950	1.012	0.951	1.04
2027-28	1.101	0.878	0.945	1.013	0.949	1.06
2028-29	1.109	0.899	0.949	1.016	0.942	1.06
2029-30	1.116	0.919	0.947	1.019	0.948	1.08
2030-31	1.137	0.931	0.946	1.020	0.935	1.08

4. LONG TERM ENERGY AND DEMAND FORECAST

4. Long Term Energy and Power 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 prevailing 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 prevailing 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 1970-2021. The methodology of long-term load forecast is illustrated in the process flow map in Figure 4-1.

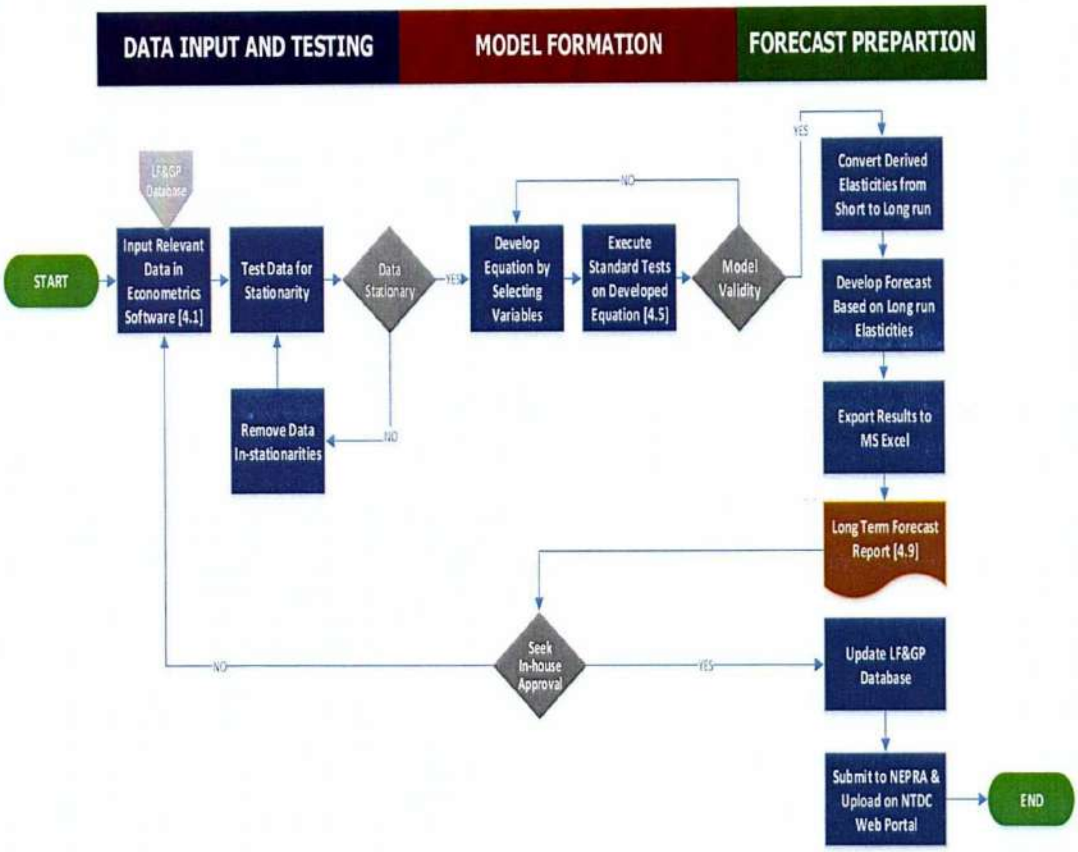

Figure 4-1: Process Flow of Methodology of Long-Term Demand Forecast

4.3 Data Sources

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

a. Historical GDP and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan 2020-21 published by Finance Division, Government of Pakistan.
b. GDP growth rate projections from FY 2022-23 to 2030-31 have been provided by the World Bank. However, the actual GDP growth rate for FY 2021-22, which is recently revised by the Pakistan Bureau of Statistics, has been considered. The GDP growth rate projections which have been considered in this plan for Normal, Low and High scenario are given in Annexure A-1, A-2, and A-3, respectively.
c. Energy Sales, Transmission & Distribution Losses and Energy Purchased data is obtained from DISCOs Performance Statistics by PPMC – June 2021
d. Category-wise average tariff is obtained from DISCOs Performance Statistics by PPMC – June 2021.
e. Peak Demand (MW) and Load management data is obtained from NPCC, KE, PITC and DISCOs
f. The demand side management targets have been provided by NEECA.

4.4 Key Considerations

4.4.1 Demand Side Management

The starting year was 2019-20 for the calculation of reduction in energy consumption due to "Energy Efficiency" targets, provided by NEECA in November, 2020. The revised energy efficiency targets by NEECA have not been received this year and hence the same are being considered. The base year for the load forecast calculation is 2020-21 for which the quantum of target determined by NEECA is 2,190 GWh. The real impact of this target on reduction of electricity utilization is assumed to be achieved and already incorporated in the sales data for FY 2020-21. It is a cumulative impact for future years, therefore, the future years' targets are rationalized by subtracting 2190 GWh from each future planning year, by Load Forecast team, presented in the Table 4-1 below. These rationalized targets have been used for energy consumption reduction in the formulation of load forecast.

Table 4-1: NEECA Energy Efficiency Targets

Energy Saving through Standardization & Labelling		
Year	**GWh (Provided by NEECA)**	**GWh (Rationalized by NTDC)**
2021-22	3,765	1,575
2022-23	5,340	3,150
2023-24	6,916	4,726
2024-25	8,491	6,301
2025-26	10,066	7,876
2026-27	11,642	9,452
2027-28	13,217	11,027
2028-29	14,792	12,602
2029-30	16,368	14,178
2030-31	16,368	14,178

4.4.2. Net Metering

Keeping in view the growing demand of net-metering connections in the country, its impact has been considered in IGCEP. The Net Metering targets for whole country except K-Electric are provided by the Alternative Energy Development Board (AEDB) and modelled at the supply side, since the generation through Net Metering will also be contributing towards meeting the Renewable Energy targets. However, the Net Metering targets for K-Electric system are considered at demand side by K-Electric.

4.4.3. Load Management

For preparation of the Long-Term Demand Forecast, load management, being carried out in the country is incorporated in the forecast. Currently, there are six factors that are contributing towards load management namely generation constraints, emergency situations, Industrial cut, technical NTDC constraints, DISCOs' constraints and DISCOs' high loss feeders (known as Aggregate Technical and Commercial (AT&C) load management). Primarily, there are only two major types of load Management i.e., AT&C and Non-AT&C. AT&C load management is being carried out deliberately on the feeders where the revenue recovery is very low due to electricity theft and other governance issues. Non-AT&C (1,684 GWh) is being carried out due to system constraints, fuel shortage and voltage profile etc. Now AT&C (12,774 GWh) based load management has been gradually factored in the demand forecast starting from year 2023-24 till the end of study horizon with the assumption that governance will improve over the time. Whereas Non-AT&C based load management is added in the base year.

Table 4-2: AT&C Losses Inclusion in Forecast

Year	GWh	Factored-in Percentage (%)
2021-22	0	0
2022-23	0	0
2023-24	639	5
2024-25	1,277	10
2025-26	2,555	20
2026-27	3,832	30
2027-28	5,748	45
2028-29	7,664	60
2029-30	10,219	80
2030-31	12,774	100

4.5. Preparation of Demand Forecast

This year for the purpose of IGCEP country wide demand forecast is developed which includes NTDC system and K Electric System

For NTDC system, the electricity consumption 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 2031, 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. Category – wise 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 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 are selected for all the four equations. These elasticities were then converted into long-term elasticities. On the other hand, projection of growth rates for independent variables such as total GDP, electricity price, etc. are taken from various sources. The long-term elasticities and the projected independent variables are subsequently used in the equation to develop the long-term energy forecast of each category using the equation below.

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

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

Table 4-3: 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 are 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 these sectors which keep their activities going.

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In compliance to prevailing Grid Code, three scenarios of load forecast are developed based on the three different projections of GDP categorized as Low scenario, Normal scenario and High scenario. In Low scenario, low projection of GDP as given in Annexure A-2 is considered. Thus, the projected energy and demand is on the lower side as given in Table 4-5. For normal scenario medium projection of GDP as given in Annexure A-1 is considered and the projected energy and demand is at the moderate level as given in Table 4-4 and similarly in high scenario, high projection of GDP is considered as given in Annexure A-3 and as a result the forecasted energy and demand forecast is at the higher side as given in Table 4-6.

Required generation (GWh) for each scenario is calculated after adding projected distribution losses at 11 kV and transmission losses at 132 kV, 220 kV and 500 kV. The calculated base year load factor is projected for the future years which is then used along with projected energy generation to get the peak demand in MW.

The demand forecast of K-Electric is developed and provided by K-Electric from 2021-22 to 2030-31. K-Electric has considered the hourly historic pattern and the projection of net-metering connections primarily for developing its forecast.

The country-wide energy forecast is then developed by adding both NTDC and K-Electric forecast for each respective year. For country-wide peak demand forecast, projected hourly pattern of NTDC and K-Electric are added and then the maximum value is sorted out to obtain country-wide demand forecast.

4.6. Energy and Power Demand Forecast Numbers

Based on the variables and methodology explained above, Table 4-4, 4-5 and 4-6 highlights forecast result for the Normal, Low and High scenarios respectively.

Table 4-4: Long-Term Energy & Power Demand Forecast - Normal Growth Scenario

Years	NTDC		K-Electric		Country	
	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)
2021-22	134,064	23,544	19,802	3,670	153,866	26,945
2022-23	134,453	24,755	21,926	4,321	156,379	28,436
2023-24	142,057	26,202	22,337	4,418	164,394	29,054
2024-25	149,502	27,625	22,554	4,574	172,056	30,583
2025-26	157,615	29,177	22,781	4,726	180,396	32,105
2026-27	165,562	30,703	23,089	4,882	188,651	33,688

2027-28	174,333	32,388	23,318	5,032	197,651	35,430
2028-29	183,155	34,089	23,538	5,213	206,693	37,191
2029-30	192,690	35,928	23,754	5,387	216,444	39,086
2030-31	204,388	38,179	24,117	5,568	228,505	41,338
CAGR	4.80%	5.52%	2.21%	4.74%	4.49%	4.87%

Table 4-5: Long-Term Energy & Power Demand Forecast - Low Growth Scenario

Years	NTDC		K-Electric		Country	
	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)
2021-22	134,064	23,544	19,802	3,670	153,866	26,945
2022-23	134,146	24,698	21,773	4,320	155,919	28,351
2023-24	141,119	26,029	22,047	4,360	163,166	28,836
2024-25	147,634	27,280	22,099	4,482	169,733	30,168
2025-26	154,542	28,608	22,139	4,592	176,681	31,440
2026-27	161,032	29,863	22,239	4,703	183,271	32,722
2027-28	168,113	31,233	22,253	4,802	190,366	34,120
2028-29	175,027	32,576	22,261	4,927	197,288	35,489
2029-30	182,454	34,020	22,275	5,043	204,729	36,955
2030-31	191,843	35,836	22,390	5,166	214,233	38,744
CAGR	4.06%	4.78%	1.37%	3.87%	3.75%	4.12%

Table 4-6: Long-Term Energy & Power Demand Forecast - High Growth Scenario

Years	NTDC		K-Electric		Country	
	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)	Energy (GWh)	Peak Demand (MW)
2021-22	134,064	23,544	19,802	3,670	153,866	26,945
2022-23	134,826	24,824	22,078	4,351	156,904	28,532
2023-24	143,212	26,415	22,628	4,475	165,840	29,310
2024-25	151,827	28,055	23,014	4,668	174,841	31,081
2025-26	161,463	29,889	23,434	4,861	184,897	32,909
2026-27	171,279	31,763	23,962	5,067	195,241	34,865
2027-28	182,271	33,863	24,422	5,270	206,693	37,053
2028-29	193,635	36,039	24,889	5,512	218,524	39,321
2029-30	206,035	38,417	25,359	5,752	231,394	41,786
2030-31	220,947	41,272	25,978	5,998	246,925	44,668
CAGR	5.71%	6.44%	3.06%	5.61%	5.40%	5.78%

The Chart 4-1 shows peak demand projections of Normal, Low and High growth scenarios:

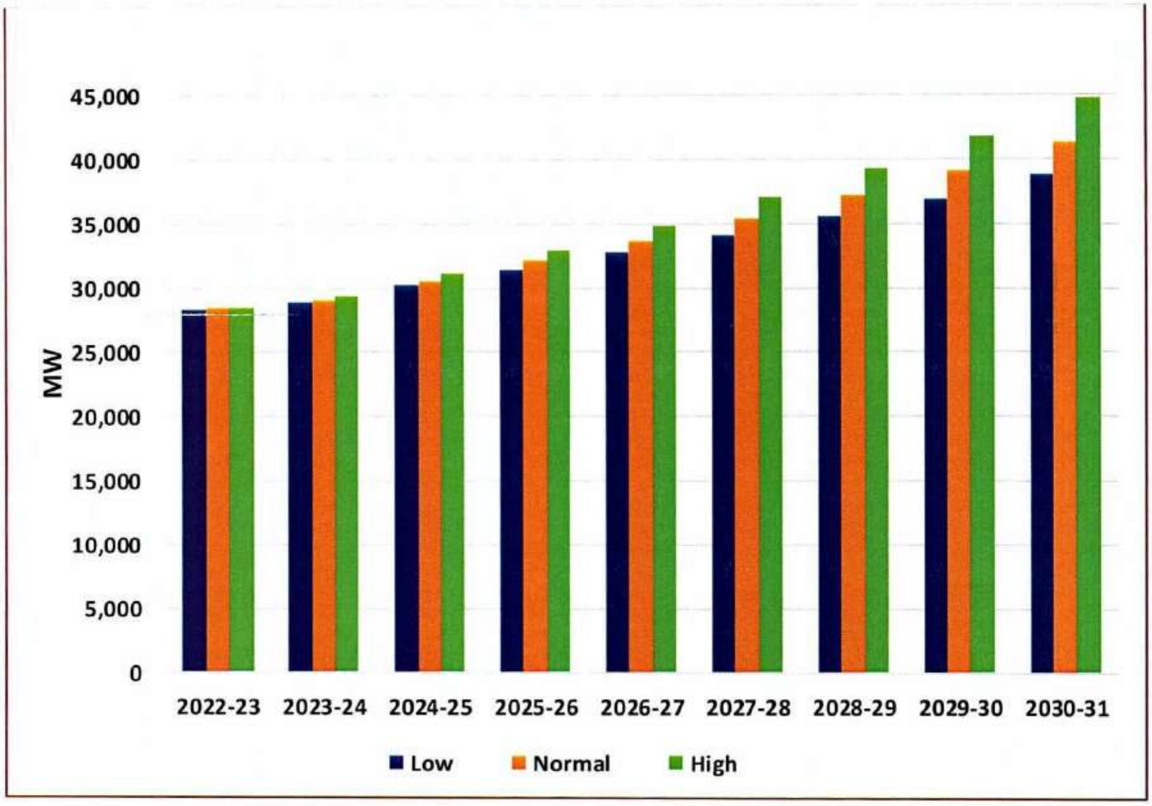


Chart 4-1: Peak Demand (MW) Forecast 2022-2031

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 87,600 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 which is then adjusted to cater for the upcoming net – metering connections in the country. The load duration curve for the year 2026-27 and 2030-31 is given Chart 4-2.

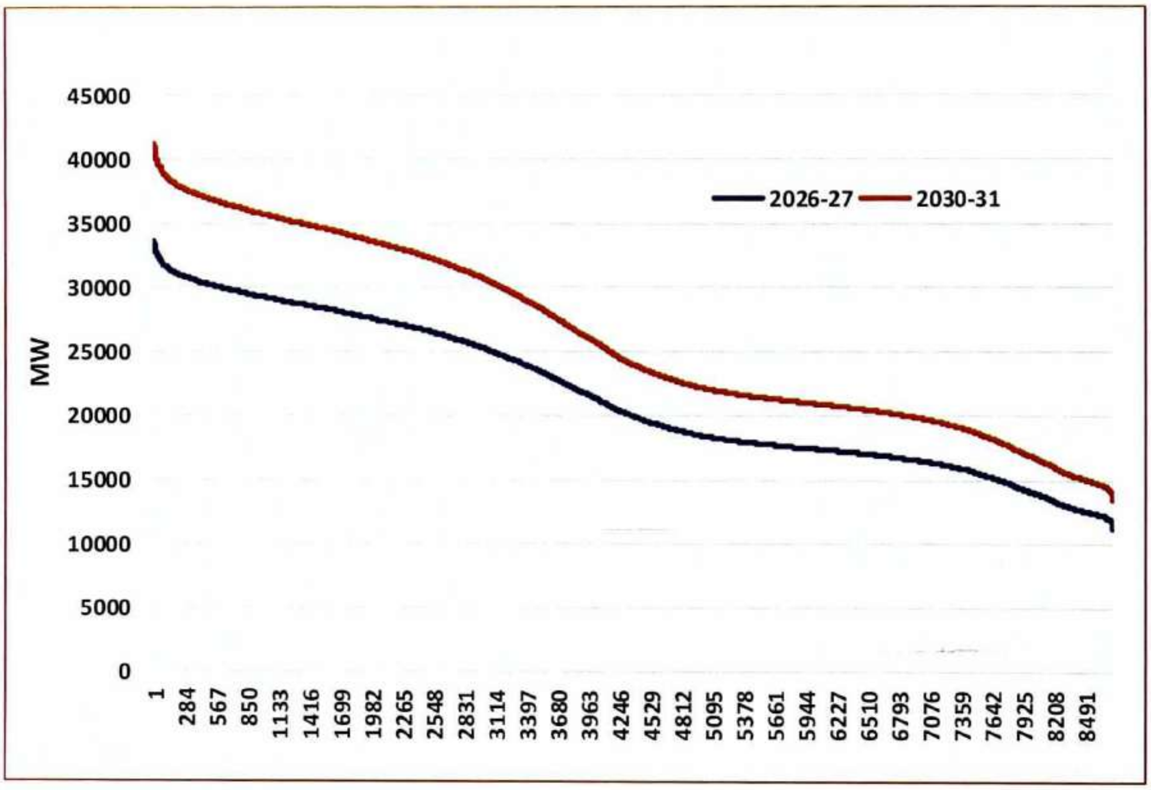


Chart 4-2: Load Duration Curve (2026-27 & 2030-31)

5. INSIDE THE IGCEP

5. Inside the IGCEP

5.1. Introduction

The key objective of IGCEP is to develop a least cost, 10-year indicative generation expansion plan for the whole country to meet the load and energy demand in a reliable and sustainable manner while maximizing use of indigenous resources for energy security. NTDC prepares this IGCEP every year to meet its regulatory requirement, as stipulated in the Planning Code 4 of the prevailing Grid Code, which takes into account the assumptions laid down in National Electricity Policy 2021 (NEP) along with some additional assumptions and identified constraints, if any. The plan is to be reviewed and approved by NEPRA – the electricity regulator. The following section describes the key parameters and results of the generation planning study.

5.2. Assumptions of IGCEP

The IGCEP 2022-31 has been developed in the light of the criteria laid down in National Electricity Policy (NEP) along with some additional assumptions related to certain specific projects have also been considered based on the ground realities and updated data / status of these projects as per discussion held in the NTDC Board Technical Committee meetings held in March / April 2022. The same are reproduced below:

1. Out of the three load forecast scenarios (Low, Normal, High), 'normal' served demand forecast scenario for base case, has been used based on the following inputs:
   i. Historical GDP and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan 2020-21 published by Finance Division, Government of Pakistan.
   ii. GDP growth rate projections from FY 2022-23 to 2030-31 have been provided by the World Bank. However, the actual GDP growth rate for FY 2021-22, which is recently revised by the Pakistan Bureau of Statistics, has been considered. The GDP growth rate projections which have been considered in this plan for Normal, Low and High scenario are given in Annexure A-1, A-2, and A-3, respectively.
   iii. Energy Sales, Transmission & Distribution Losses and Energy Purchased data is obtained from DISCOs Performance Statistics by PPMC – June 2021
   iv. Category-wise average tariff is obtained from DISCOs Performance Statistics by PPMC – June 2021.
2. Planning horizon of the study is 2022 to 2031 with annual updating.
3. Reserve and reliability requirements (LOLP = 1%) have been considered as per prevailing Grid Code.
4. Retirement of existing thermal power Project including GENCOs has been 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 have been given a minimum dispatch as per contractual obligations.
6. Fuel costs as per Merit order of June 2022, have been considered.

7. Fixed O&M and variable O&M as per NEPRA's quarterly indexation of March 2022, as available on NEPRA's website, has been considered.
8. Fixed O&M costs of power Project built under 1994 Power Policy are not available on NEPRA's website, so these costs have been obtained from previous data available with Power System Planning, NTDC and CPPA (G).
9. A project has been considered as **'committed'** and its capital cost or CAPEX is not 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 Project 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. RE Project (Wind, Solar, Bagasse) enlisted in Category I & II of CCoE's decision dated 4th April 2019.
   iv. 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.
10. Cost data of committed projects has taken as per data/information provided by the concerned project executing agency and NEPRA determined tariff.
11. For nuclear power Project, Capital Cost, Variable O&M cost and Fixed O&M cost and operational data as conveyed by Pakistan Atomic Energy Commission (PAEC) has been considered.
12. Local and imported coal power Project: Capital Cost, Variable O&M cost, Fixed FCC and Fixed O&M cost has been taken from the latest NEPRA determined tariff for respective technology.
13. RLNG based OCGT power Project: Fuel cost, Fixed O&M cost and Variable O&M cost of latest available OCGT Project is considered while Capital cost for OCGT has been considered as conveyed by the concerned project executing agency or as per best international practice.
14. The CAPEX of wind and solar has been determined based on the annualized cost of 4 cents/kWh as conveyed by AEDB, subject to approval by NEPRA.
15. Bagasse based power Project: Capital cost, Variable O&M cost, Fixed O&M cost and Fuel cost have been taken from the latest available NEPRA's tariff determination.
16. Hydro power Project: Capital cost and Fixed O&M cost have been considered as shared by the concerned project executing entities.
17. All years correspond to fiscal years e.g., 2025 is the fiscal year from July 1, 2024 to June 30, 2025.

18. Only Shahtaj is taken as a committed project from Category-I and II bagasse-based projects since it has been awarded revised tariff by NEPRA. Further, yearly candidate block of 100 MW bagasse has been considered from the year 2024-25 onwards.
19. 370 MW_p of net metering is considered for NTDC System each year.
20. Candidate hydro power projects under 20 MW and connected below 132 kV (and hence, not in central dispatch) have not been considered.
21. No candidate thermal or RE projects have been considered by name.
22. Siddiqsons CFPP has been removed from the list of committed projects, due to LOS expiry and presently under litigation as per PPIB.
23. Gwadar CFPP has been considered on Local Coal as conveyed by relevant project executing agency, i.e., PPIB
24. The COD of CASA has been assumed as August 2024.
25. Diamer Bhasha HPP has been delayed beyond the study horizon of the current version of IGCEP owing to the progress made so far by the project, as decided in a meeting held at MoE (PD), among representatives from NTDC, PPIB, MoE (PD), WAPDA and MoW&R.
26. Existing Engro Powergen CCPP has been modelled as per data provided by M/s Engro CCPP representative in view of its Gas Depletion Mitigation Plan (GDMP). It is to highlight that minimum take or pay dispatch of 50% on the available yearly Permeate gas has been considered.
27. Pursuant to approved NE Policy 2021, K-Electric system has also been included in the current version of IGCEP.
28. For candidate local coal-based projects, the fixed fuel cost component (FFCC) of 11.2 \$/Ton (71.821 \$/kW-year) and fuel price of 9.97 \$/Ton (0.88 \$/GJ) have been considered as per TCEB determination of 2020 pertaining to Thar Block-II at 30.8 MTPA.
29. In order to cater for network requirements/constraints, some existing projects located near load center have been considered as "Must Run", for summer months, i.e., May to September uptill year 2025.
30. Minimum Despatch of 500 MW from Existing KAPCO CCPP (Block-I and Block-II) in the months of May to September uptill year 2025 has been considered, beyond its PPA expiry i.e., Oct. 2022, owing to network requirements/constraints, whereas, the remaining capacity (Block-III) has been retired as per PPA expiry. It is pertinent to mention that the requirement of KAPCO beyond its PPA expiry will be assessed in ongoing Transmission System Expansion Plan (TSEP), accordingly competent forum will be approached, after consensus among concerned stakeholders i.e., NTDC, CPPA-G and KAPCO, for PPA extension or otherwise and the same will be considered in next iteration of IGCEP.
31. 140 MW Habibullaah Costal (HCPC) and 31 MW Altern Energy Limited (AEL) have not been considered in the existing installed capacity owing to termination of Gas Supply Agreement (GSA) and de-licensing by NEPRA, respectively.
32. The COD of a committed project i.e., 84 MW Gorkin Matiltan HPP, has been assumed as of July 2024 instead of July 2023 in view of its latest progress.
33. Following lead time criterion for the candidate power projects has been assumed:

a. 4 years for coal power projects; earliest year of availability, July 2026

b. 2 years for Utility Solar PV, and Wind power projects; earliest year of availability, July 2024

c. For certain Hydro power projects, the earliest year of availability is July 2028 and onwards (details given in Anexure-B6)

Either Due to their remote locations

Or non-availability of feasibility studies for power evacuation

34. All the costs have been indexed as of March 2022.

For Hydro power projects, 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. Conditions for Optimized / Selected Power Projects

The following conditions are proposed herewith for all the candidate projects being optimized in IGCEP 2022-31 for consideration of Authority while issuing tariff:

a. The cost nos (CAPEX & OPEX) approved by NEPRA for an optimized project shall either be equal or less than the cost used in IGCEP, if in any case the cost given by NEPRA to any optimized project is more than the one used in IGCEP, then a re-run shall be required to assess the viability / optimization of that very project on the new cost.

b. For issuance of LOS to the private sector projects and PC-1 approval of the public sector projects, the relevant agency must ensure that the project cost determined/approved by NEPRA shall either be less than or equal to the cost considered in IGCEP for that particular optimized project, otherwise, re-evaluation of the project on the basis of new cost shall be done.

In addition to above, it is re-iterated that selection of any generation project in IGCEP does not ensure any guarantee to execute that project which shall have to undergo approvals from all the relevant government authorities.

5.4. 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 50% for existing imported coal-based power projects (Sahiwal, China HUBCO & Port Qasim), and three low btu gas-based projects (Uch-II, Engro and Foundation).

5.5. 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.

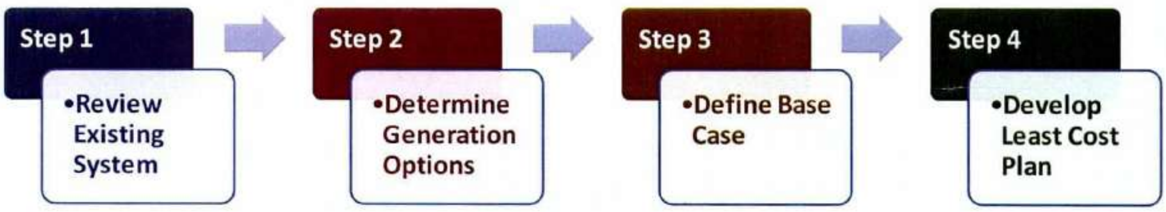


Figure 5-1: The IGCEP Data Modelling Approach

5.6. 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. 177.95 (March 2022)
CPI (US)	277.948
CPI (Local)	269.27

5.7. Existing Power Generation of Country

Total installed capacity of existing NTDC system is 37,949 MW as of June 2022, whereas the de-rated capacity is equivalent to 35,765 MW. Similarly, for the K-Electric system, the installed and de-rated capacities stand 3,319 MW and 2,941 MW, respectively.

5.8. Retirement of Existing Power Projects

A significant quantum i.e., 7,339 MW of the existing thermal power projects are scheduled to be retired from NTDC system during the planning horizon of the IGCEP 2022-31. It is highlighted that 144 MW GTPS Block 4 U (5-9) has been retired during FY 2021-22, hence the same has been excluded from existing installed capacity. The retirement schedule for the

IGCEP 2022-31 is provided in the Table 5-2. For the purpose of the IGCEP, a power project stands retired either as per its PPA/EPA term or relevant CCoE decision. Major retirement of generation capacity for the IGCEP 2022-31 corresponds to RFO based power projects, followed by Local Gas and then RLNG based power projects.

Table 5-2: Retirement Schedule of Power Projects in the Existing NTDC System

Sr. #	Name of the Power Station	Installed Capacity (MW)	Fuel Type	Retirement Year (FY)						Rationale
				23	26	27	29	30	31	
1	Guddu-II U (5-10)	620	Gas	✓						CCoE decision
2	Jamshoro-I U1	250	RFO	✓						
3	Jamshoro-II U4	200	RFO	✓						
4	Muzaffargarh-I U1	210	RFO	✓						
5	Muzaffargarh-I U2	210	RFO	✓						
6	Muzaffargarh-I U3	210	RFO	✓						
7	Muzaffargarh-II U4	320	RFO	✓						
8	KAPCO 1	400	RLNG		✓					PPA extended owing to network constraints*
9	KAPCO 2	900	RLNG		✓					
10	KAPCO 3	300	RLNG	✓						PPA expiry
11	Liberty	225	Gas			✓				
12	HUBCO	1,292	RFO			✓				
13	Kohinoor	131	RFO			✓				
14	AES Lalpir	362	RFO				✓			
15	AES Pakgen	365	RFO				✓			
16	FKPCL	172	RLNG					✓		
17	Saba	136	RFO					✓		
18	Uch	586	Gas						✓	
19	Rousch	450	RLNG						✓	
	Total (MW)	**7,339**								

Note: **A sensitivity analysis to assess the requirement of existing KAPCO CCPP beyond its PPA expiry, in years to come will be conducted in the on-going Transmission System Expansion Plan (TSEP). However, considering the historical dispatch of KAPCO owing to network constraints in the region, two blocks of KAPCO have been assumed to stay in system uptill the year 2026.*

The retirement plan of K-Electric system is shown in Table 5-3. A total of 682 MW capacity is going to be retired from K-E system in the upcoming years.

Table 5-3: Retirement Schedule of Power Projects in the Existing K-Electric System

Sr. #	Name of the Power Station	Installed Capacity (MW)	Fuel Type	Retirement Year (FY)		Rationale
				23	24	
1	GAEL	136	RFO	✓		PPA expiry
2	TPL	126	RFO	✓		
3	BQPS1-U1	210	RLNG		✓	
4	BQPS1-U2	210	RLNG		✓	
	Total (MW)	682				

5.9. Committed Projects

Power projects considered as committed projects based on the criteria shown in the Figure 5-2.

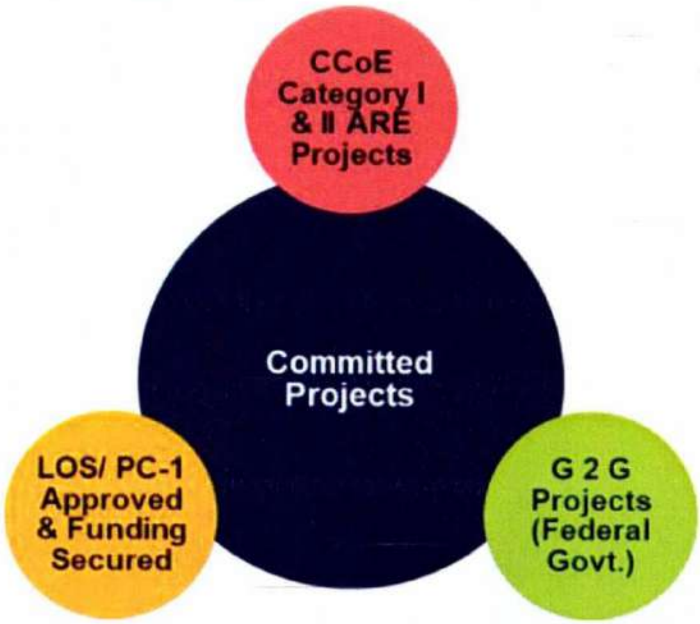


Figure 5-2: Committed Projects Criteria

5.9.1. List of Committed Projects

The committed projects considered in the IGCEP are listed in the Table 5-4.

Table 5-4: List of Committed Projects

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
1	Chianwali	Hydro	PPMU	5.38	PC-1 Approved	Mar-22
2	Jabori	Hydro	GoKPK	10.20	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	PPMU	4.04	PC-1 Approved	Jun-22
4	Thar TEL	Local Coal	PPIB	330	LOS (Issued)	Jul-22
5	Trimmu	CCGT_RLNG	PPIB	1263	LOS (Issued)	Jul-22
6	Karora	Hydro	GoKPK	11.80	PC-1 Approved	Aug-22
7	Mangla (U #5-6)	Hydro	WAPDA	70	Mangla Refurbishment	Sep-22
8	Koto	Hydro	GoKPK	40.8	PC-1 Approved	Sep-22
12	Jamshoro Coal (U #1)	Imported Coal	GENCO	660	PC-1 Approved	Dec-22
13	Thal Nova	Local Coal	PPIB	330	LOS (Issued)	Dec-22
14	Thar-I (SSRL)	Local Coal	PPIB	1320	LOS (Issued)	Dec-22
9	Helios	PV	AEDB	50	Category-II Project	Apr-23
10	HNDS	PV	AEDB	50	Category-II Project	Apr-23
11	Meridian	PV	AEDB	50	Category-II Project	Apr-23
15	Jagran-II (U #1)	Hydro	AJK-HEB	12	PC-1 Approved	Apr-23
16	Mangla (U #3-4)	Hydro	WAPDA	70	Mangla Refurbishment	May-23
17	Jagran-II (U #2)	Hydro	AJK-HEB	12	PC-1 Approved	May-23
18	Jagran-II (U #3)	Hydro	AJK-HEB	12	PC-1 Approved	Jul-23
19	Jagran-II (U #4)	Hydro	AJK-HEB	12	PC-1 Approved	Jul-23
20	Chamfall	Hydro	AJK-HEB	3.22	PC-1 Approved	Aug-23

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
21	Access_Electric	PV	AEDB	10.00	Category-I Project	Sep-23
22	Access_Solar	PV	AEDB	11.52	Category-I Project	Sep-23
23	Manjhand	PV	GoS	50	PC-1 Approved	Sep-23
24	Siachen	PV	GoS	100	Category-II Project	Sep-23
25	Kurram Tangi	Hydro	WAPDA	18.00	PC-1 Approved	Oct-23
26	Riali-II	Hydro	PPIB	7.08	LOS (Issued)	Dec-23
27	Zorlu	PV	PPDB	100	Category-II Project	Dec-23
28	Lawi	Hydro	GoKPK	69	PC-1 Approved	Apr-24
29	Suki Kinari (U #1)	Hydro	PPIB	221	LOS (Issued)	May-24
30	Safe	PV	AEDB	10.00	Category-I Project	Jun-24
31	Trans_Atlantic	Wind	AEDB	50	Category-II Project	Jun-24
32	Western	Wind	AEDB	50	Category-II Project	Jun-24
33	Gorkin Matiltan	Hydro	GoKPK	84	PC-1 Approved	Jul-24
34	Mangla (U #1-2)	Hydro	WAPDA	70	Mangla Refurbishment	Jul-24
35	Tarbela Ext5 (U #1)	Hydro	WAPDA	510	PC-1 Approved	Jul-24
36	Suki Kinari (U #2)	Hydro	PPIB	221	LOS (Issued)	Jul-24
37	CASA	Cross Border Interconnection	NTDC	1000	G2G	Aug-24
38	Tarbela Ext5 (U #2)	Hydro	WAPDA	510	PC-1 Approved	Aug-24
39	Shahtaj	Bagasse	AEDB	32	Category-I Project	Aug-24
40	Tarbela Ext5 (U #3)	Hydro	WAPDA	510	PC-1 Approved	Sep-24
41	Suki Kinari (U #3)	Hydro	PPIB	221	LOS (Issued)	Sep-24
42	Suki Kinari (U #4)	Hydro	PPIB	221	LOS (Issued)	Nov-24

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
43	Kathai-II	Hydro	PPIB	8.00	LOS (Issued)	Dec-24
44	Gwadar	Local Coal	PPIB	300	LOS (Issued)	Aug-25
45	Mangla (U #9-10)	Hydro	WAPDA	70	Mangla Refurbishment	Sep-25
46	Chapari Charkhel	Hydro	GoKPK	10.56	PC-1 Approved	Sep-25
47	Dasu (U #1)	Hydro	WAPDA	360	PC-1 Approved	May-26
48	Mohmand Dam (U #1)	Hydro	WAPDA	200	PC-1 Approved	May-26
49	Dasu (U #2)	Hydro	WAPDA	360	PC-1 Approved	Jul-26
50	Mohmand Dam (U #2)	Hydro	WAPDA	200	PC-1 Approved	Jul-26
51	Dasu (U #3)	Hydro	WAPDA	360	PC-1 Approved	Aug-26
52	Mohmand Dam (U #3)	Hydro	WAPDA	200	PC-1 Approved	Sep-26
53	Dasu (U #4)	Hydro	WAPDA	360	PC-1 Approved	Nov-26
54	Mangla (U #7-8)	Hydro	WAPDA	30	Mangla Refurbishment	Nov-26
55	Mohmand Dam (U #4)	Hydro	WAPDA	200	PC-1 Approved	Nov-26
56	Dasu (U #5)	Hydro	WAPDA	360	PC-1 Approved	Feb-27
57	Keyal Khwar (U #1)	Hydro	WAPDA	64	PC-1 Approved	Feb-27
58	Dasu (U #6)	Hydro	WAPDA	360	PC-1 Approved	May-27
59	Keyal Khwar (U #2)	Hydro	WAPDA	64	PC-1 Approved	May-27
60	Gabral Kalam	Hydro	GoKPK	88	PC-1 Approved	Nov-27
61	Madyan	Hydro	GoKPK	157	PC-1 Approved	Nov-27
62	Balakot	Hydro	GoKPK	300	PC-1 Approved	Dec-27
63	Azad Pattan (U #1)	Hydro	PPIB	175.18	LOS (Issued)	Dec-28
64	Azad Pattan (U #2)	Hydro	PPIB	175.18	LOS (Issued)	Mar-29

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
65	Azad Pattan (U #3)	Hydro	PPIB	175.18	LOS (Issued)	Jun-29
66	Azad Pattan (U #4)	Hydro	PPIB	175.18	LOS (Issued)	Sep-29
67	Kohala (U #1)	Hydro	PPIB	275.00	LOS (Issued)	Jun-30
68	Kohala (U #2)	Hydro	PPIB	275.00	LOS (Issued)	Aug-30
69	Kohala (U #3)	Hydro	PPIB	275.00	LOS (Issued)	Oct-30
70	Kohala (U #4)	Hydro	PPIB	275.00	LOS (Issued)	Dec-30
71	Kohala (U #5)	Hydro	PPIB	12.00	LOS (Issued)	Feb-31
72	Kohala (U #6)	Hydro	PPIB	12.00	LOS (Issued)	Mar-31
Total Committed (MW):				**14,268**		
73	Net Meter	PV	AEDB	370	Committed	Jul-22
74	Net Meter	PV	AEDB	370	Committed	Jul-23
75	Net Meter	PV	AEDB	370	Committed	Jul-24
76	Net Meter	PV	AEDB	370	Committed	Jul-25
77	Net Meter	PV	AEDB	370	Committed	Jul-26
78	Net Meter	PV	AEDB	370	Committed	Jul-27
79	Net Meter	PV	AEDB	370	Committed	Jul-28
80	Net Meter	PV	AEDB	370	Committed	Jul-29
81	Net Meter	PV	AEDB	370	Committed	Jul-30
Total Net Meter (MW_p):				**3,330**		

5.10. New Generation Options

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

For NTDC system:

a. Steam PP on Thar Coal (660 MW); reference – Engro Thar CFPP / TCEB and CAPEX from upfront local coal tariff 2017

b. Gas Turbine on RLNG (400 MW); reference – Trimmu Open Cycle (operational data) and CAPEX as per data available with international resource (JICA)

c. Nuclear Steam PP on Uranium (1,200 MW); reference - PAEC candidate

d. Wind Turbine

   i. 500 MW each in July 2024 & July 2025, no limit from July 2027 onwards;
   ii. Reference cost and parameters – as provided by AEDB, subject to approval by NEPRA

e. Solar PV

   i. Utility scale: 3,120 MW_p in July 2024, 1,300 MW_p yearly from July 2025 onwards
   ii. Feeder Based (DG): 500 MW_p in July 2023, 750 MWp each in July 2024 & July 2025
   iii. Net Metering: 370 MW_p yearly from July 2022 onwards
   iv. Reference cost and parameters – as provided by AEDB, subject to approval by NEPRA

f. Bagasse (Block of ≤ 100 MW); reference – operational parameters -Upfront Tariff 2017 and CAPEX from Shahtaj

g. Jamshoro Imported Coal Unit-2 (660 MW) – GENCOs candidate

h. C-5 Nuclear Power Project (1,200 MW) – PAEC candidate

i. Steam PP on Thar Coal (330 MW); reference – Siddiqsons CFPP and TCEB

For K-Electric system:

a. Steam PP on Thar Coal (330 MW); reference – Siddiqsons CFPP and TCEB

b. Wind Turbine (Block of ≤ 50 MW); reference cost and parameters – as provided by AEDB, subject to approval by NEPRA

c. Solar PV (Block of ≤ 150 MW_p); reference cost and parameters – as provided by AEDB, subject to approval by NEPRA

5.11. Hydro Projects and Screening

Data for hydro power projects was obtained from the relevant project executing agencies. A total of 55 Hydro Candidates are given to the model for optimization. The candidate hydro projects considered for optimization with their Indexed Capital Cost and Annualized Cost as per latest NEPRA available indexation are presented in Annexure B-3 & Annexure B-5 respectively.

5.12. Performance Characteristics of Generic Thermal Candidates

Generic Candidate thermal options include Gas Turbines (GTs) using RLNG and Steam Turbines (STs) using 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

h

select the least cost supply options taking into account technical characteristics, economic and financial parameters and operational requirements. Table 5-5 shows the performance characteristics of the thermal candidate projects.

Table 5-5: Performance Characteristics of Generic Thermal Power Projects

	Performance Characteristics	Jamshoro Coal Fired Steam Unit-II	Coal Fired Steam at Thar	Coal Fired Steam at Thar-K-Electric	Coal Fired Steam-II at Thar	Combustion Turbine on RLNG	Generic Nuclear PP	Bagasse
A	Installed Capacity (MW)	660	660	330	330	400	1,200	100
B	Net Capacity (MW)	627	607	304	304	388	1,111	100
Technical Parameters								
C	Heat Rate (GJ/MWh)	9.11	9.23	9.73	9.23	9.46	9.57	12.68
D	Scheduled Outage (d/year)	36	36	36	36	30	35	-
E	Forced Outage (Hours %)	6.78	6.8	6.8	6.8	4.8	1.2	-
F	Economic Life (years)	30	30	30	30	30	60	30
O&M								
G	Fixed FCC ($/Ton)	-	11.2	11.2	11.2	-	-	-
H	Fixed ($/kW-year)	5.06	26.6 + 71.81*	26.6 + 71.81*	25.17 + 71.81*	13.29	73.89	19.23
I	Variable ($/MWh)	2.85	6.21	6.17	5.93	3.14	-	3.29
J	CAPEX ($/kW)	669	1,419	1,419	1,419	476	4,319	809
K	Earliest availability (year)	2028	2027	2027	2027	2025	2030	2025

*Fixed Fuel Cost Component (FCC)

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/year) - Screening Curve (Annexure B-4.1)
b. Unit Generation Cost (cents/kWh) - Screening Curve (Annexure B-4.2)

Although the mechanism of project 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 projects at various project factors.

These curves are the plots of unit generation cost on the y-axis and the project capacity factors on the x-axis. The total cost includes the annual capital recovery factor, fuel cost and annual O&M cost. The projects are ranked for each range of operating factors i.e., base load, intermediate and peak load operation. The project ranked lowest is introduced / selected first and remaining projects follow based on increasing order of merit / rank as per the system requirement.

5.13. Parameters of the Candidate REs

RE generation options including Solar PV, Wind, Battery Energy Storage System (BESS), hybrid and bagasse-based projects are other viable generation options. In this perspective, hybrid technologies are also to be modelled as candidate along with solar PV and wind, subject to data provision by the relevant agencies. In this regard, in response to NTDC's request to relevant agencies, AEDB has 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-availability of data (cost, hourly profile, etc.), hybrid technologies are not modelled in the current iteration of the IGCEP. Table 5-6 shows the parameters of the candidate wind and solar PV projects.

Table 5-6: Parameters of Candidate Wind and Solar PV Projects

#	Technology	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Project Factor	Annualized Cost of Energy	
		(MW)	(Year)	($/kW-Yr)	($/kW)	(GWh)	(%)	(c/kWh)	($/kW-Yr)
1	Solar PV Utility*	100	2025	7.19	638	193.39	22.1%	4.0	77.44
2	Solar Feeder (DG)*	100	2024	7.19	571	175.20	20%	4.0	70.08
3	Wind	100	2025	17.53	1,177	367.92	42%	4.0	147.17

*Solar values are in MW_p

6. THE IGCEP STUDY OUTPUT

6. The IGCEP Study Output

6.1. Introduction

The key objective of IGCEP is to develop a least cost, 10-year indicative generation expansion plan for the whole country to meet the load and energy demand in a reliable and sustainable manner while maximizing use of indigenous resources. NTDC prepares this IGCEP every year to meet its regulatory requirement, as stipulated in the Planning Code 4 of the prevailing Grid Code, which takes into account the Assumption Sets as mentioned in section 5.2 and assumptions laid down in NEP. The plan is to be reviewed and approved by NEPRA – the electricity regulator. The following section describes the key parameters and results of the generation planning study.

6.2. Defining Base Case

Major features of the Base Case are as follows:

a. Assumption Sets as mentioned in section 5.2 and assumptions laid down in NEP
b. GDP projections by World Bank (average GDP growth rate 4.30%)
c. Normal scenario of long-term load forecast
d. Existing contractual obligations - maintained till the end of contract

6.3. Other Scenarios

In addition to the base case, following scenarios have also been simulated through this study:

a. Scenario - I: Low Demand Scenario

All other parameters are same as those of the base case except for the demand numbers i.e., the average GDP growth rate of 3.40% has been used to devise load demand forecast till 2031. The results are attached as Annexure – C.

b. Scenario - II: High Demand Scenario

All other parameters are same as those of base case except for the demand numbers i.e., the average GDP growth rate of 5.42% has been used to devise load demand forecast till 2031. The results are attached as Annexure – D.

c. Scenario - III: Diamer Bhasha HPP in 2029

Although Diamer Bhasha HPP is not considered in the Base case, owing to its COD beyond study horizon, however a sensitivity analysis has been carried out by considering Diamer Bhasha HPP as a committed power project with CAPEX in the year 2029. The results are attached as Annexure – E.

d. Scenario - IV: Chashma Nuclear (C-5) for Energy Security

Although Chashma Nuclear (C-5) is considered as a candidate project in the Base case but this sensitivity analysis has been carried out by considering Chashma Nuclear (C-5) as a

h

committed power project with CAPEX in the year 2029. The results are attached as Annexure – F.

e. Scenario – V: Local Coal inclusion in 2027 and 2030

Although generic local coal-based project is considered as a candidate project in the Base case but this sensitivity analysis has been carried out by considering 1,320 MW of domestic coal-based projects as a committed power project with CAPEX in the year 2027 & 2030. The results are attached as Annexure – G.

f. Scenario – VI: Unconstrained VRE Scenario

All other parameters are same as those of the base case except candidate utility solar PV and Wind power projects are unconstrained i.e., no annual limit. However, only 2,000 MW_p solar feeder-based/DG is considered as candidate throughout the study horizon (starting from July 2023). The results are attached as Annexure – H.

6.4. 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 2022 – 2031. 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 2022-23, the installed capacity of the whole country from all generation sources will be around 43,198 MW and the demand will be equal to 28,425 MW whereas in 2030-31, and installed capacity will be 68,667 MW and demand will be equal to 41,338 MW. Chart 6-1 shows that sufficient generation shall be added to satisfy the specified reliability criteria and reserve requirements of the system.

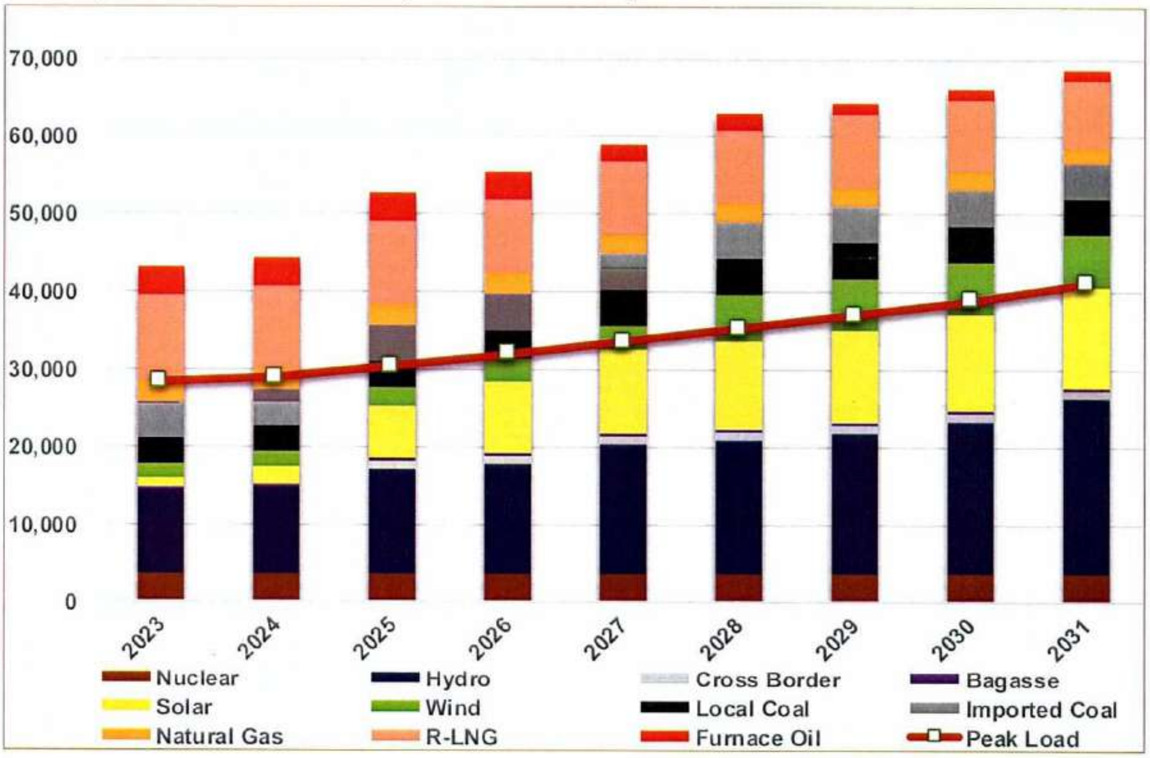


Chart 6-1: Installed Capacity vs Peak Demand (MW) 2022-23 to 2030-2031

On the other hand, energy generation by the power projects in the country has been optimized with the energy forecast by the year 2030-31 as shown in Chart 6-2. By the year 2030-31, 228,505 GWh of the energy demand is met, in which 62% of energy generation is contributed by RE sources comprising of 41% by hydro, 1% by baggase and 10% each by wind and solar PV. The remaining 39% is provided by conventional thermal sources.

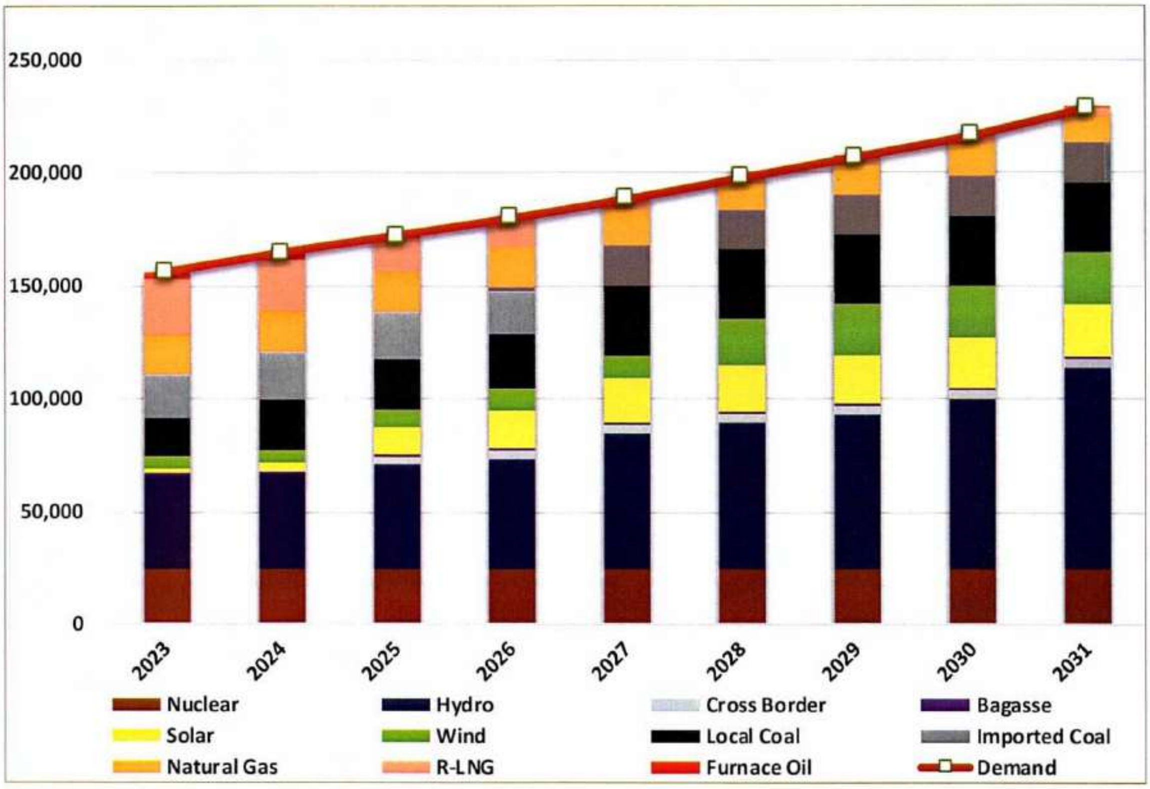


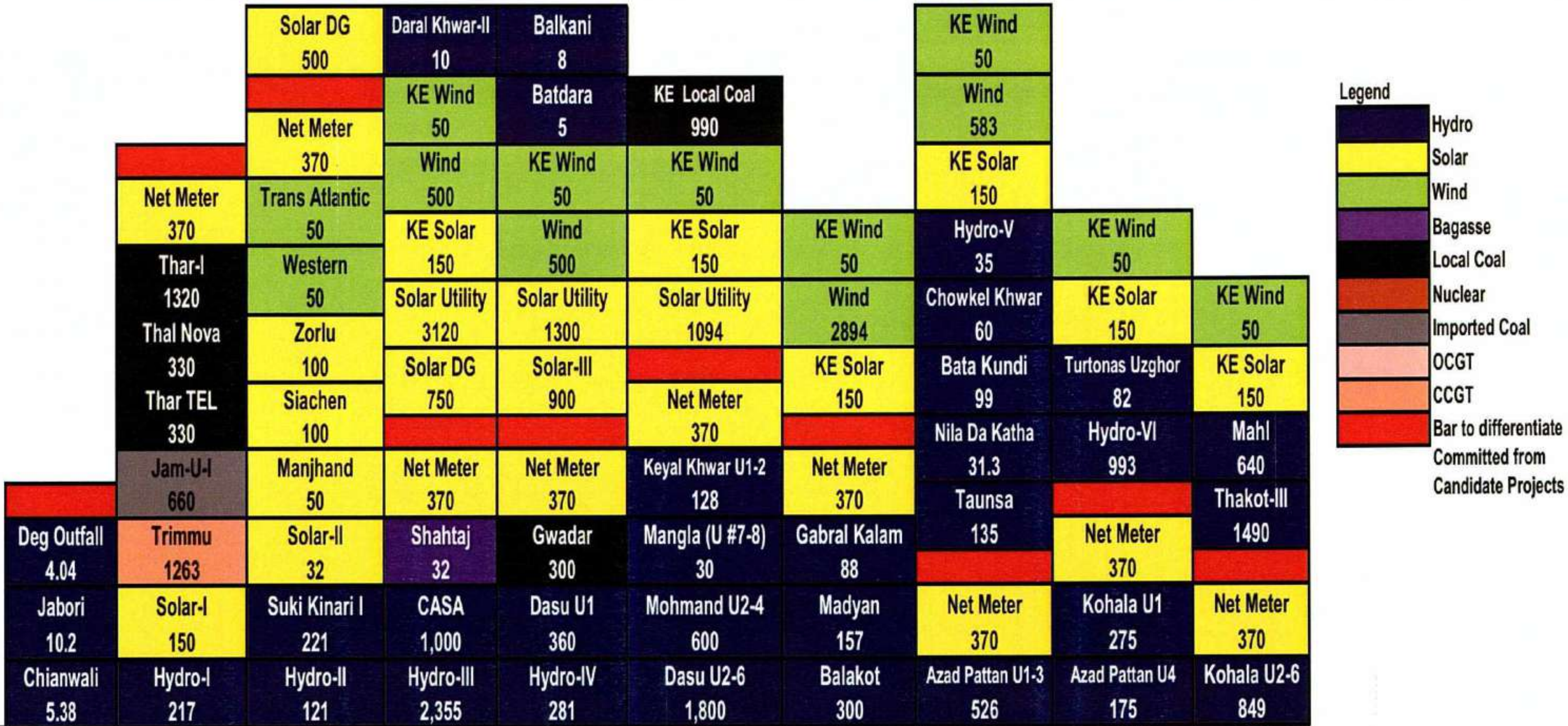
Chart 6-2: Annual Energy Generation vs Demand (GWh) 2022-23 to 2030-31

Chart 6-3 shows the total share of the existing, committed and optimized power projects in the installed capacity for the next nine years, starting from 2022-23 to the year 2030-31.

Chart 6-3: Share of Total Installed capacity (MW) 2022-31

Table 6-1: Optimized Generation Capacity Additions (2024-31)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder/DG MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	13	-	1,300	750	150	500	50	-	2,763	7,842
2027	-	990	-	-	1,094	-	150	-	50	-	2,284	10,126
2028	-	-	-	-	-	-	150	2,894	50	-	3,094	13,220
2029	-	-	360	-	-	-	150	583	50	-	1,143	14,364
2030	-	-	993	82	-	-	150	-	50	-	1,275	15,639
2031	-	-	2,130	-	-	-	150	-	50	-	2,330	17,969
Total	**-**	**990**	**3,506**	**82**	**5,514**	**2,000**	**1,050**	**4,477**	**350**	**-**	**17,969**	



Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Committed	20	4,270	724	3,387	941	2,558	545	526	450	849	14,270
Candidate	0	0	500	4,580	2,763	2,284	3,094	1,143	1,275	2,330	17,969
Net Meter	0	370	370	370	370	370	370	370	370	370	3,330
Total	20	4,640	1,594	8,337	4,074	5,212	4,009	2,039	2,095	3,549	35,569

Figure 6-1: IGCEP 2022-31 Generation Sequence

Due to limited space, in Figure 6-1, several projects (Solar PV and Hydro) being commissioned in the same year are combined together in the form of blocks for the purpose of reporting. The detail of these blocks, is provided in Table 6-2.

Table-6-2: Break-up of Blocks

Sr.No.	Year	Block	Name of Project	Installed Capacity MW
1	2023	Hydro-I	Mangla (U #5-6)	70
2			Karora	12
3			Koto	41
4			Jagran-II (U #1-2)	24
5			Mangla (U #3-4)	70
		Sub Total		**217**
6		Solar-I	Helios	50
7			HNDS	50
8			Meridian	50
		Sub Total		**150**
Total (2023)				**367**
1	2024	Hydro-II	Jagran-II (U #3)	12
2			Jagran-II (U #4)	12
3			Chamfall	3
4			Kurram Tangi	18
5			Riali-II	7
6			Lawi	69
		Sub Total		**121**
7		Solar-II	Access_Electric	10
8			Access_Solar	12
9			Safe	10
		Sub Total		**32**
Total (2024)				**153**
1	2025	Hydro-III	Mangla (U #1-2)	70
2			Gorkin Matiltan	84
3			Tarbela Ext5 (U #1-3)	1,530
4			Kathai-II	8
5			Suki Kinari (U #2-4)	663
Total (2025)				**2,355**
1	2026	Hydro-IV	Mangla (U #9-10)	70
2			Mohmand (U #1)	200
3			Chapari Charkhel	11
		Sub Total		**281**
4		Solar-III	Solar DG	750
5			KE Solar	150
6		**Sub Total**		**900**
Total (2026)				**281**
1	2029	Hydro-V	CJ	25
2			Taobut	10
Total (2029)				**35**

Sr.No.	Year	Block	Name of Project	Installed Capacity MW
1	2030	Hydro-VI	Arkari Gol	99
2			Asrit Kedam	215
3			Dowarian	40
4			Jagran-IV	22
5			Janawai	12
6			Kalam Asrit	238
7			Nagdar	35
8			Rajdhani	132
9			Sharmai	152.12
10			Shounter	48
Total (2030)				**993**

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

Table 6-3: PLEXOS Annual Addition of Power Projects 2022-2031

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
Generation Additions in 2021-22 (MW)			20	20			
Cumulative Addition up till 2021-22 (MW)			20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
Generation Additions in 2022-23 (MW)			4,640	4,421			
Cumulative Addition up till 2023 (MW)			4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2023-24				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
			2024-25				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			8,337	8,337			
Cumulative Addition up till 2025 (MW)			14,590	14,371			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-25
7	New_Solar_Utility	Solar	1,300	1,300	Yet to be determined	Optimized	Jul-25
8	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
9	Gwadar	Loal Coal	300	273	PPIB	LOS (Issued)	Aug-25

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25
11	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
12	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
13	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
Generation Additions in 2025-26 (MW)			4,073	4,046			
Cumulative Addition up till 2026 (MW)			18,663	18,417			
2026-27							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Solar_Utility	Solar	1,094	1,094	Yet to be determined	Optimized	Jul-26
7	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
8	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
9	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
10	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
11	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
12	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
13	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
14	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
15	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
16	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
Generation Additions in 2026-27 (MW)			5212	5134			
Cumulative Addition up till 2027 (MW)			23,875	23,551			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2027-28							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	2,894	2,894	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			4,009	4,009			
Cumulative Addition up till 2028 (MW)			27,884	27,560			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	Chowkel Khwar	Hydro	60	60	PEDO	Optimized	Jul-28
4	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
5	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
6	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
7	New_Wind	Wind	583	583	Yet to be determined	Optimized	Jul-28
8	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
9	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
10	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
11	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
12	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
13	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			2,039	2,039			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
Cumulative Addition up till 2029 (MW)			29,923	29,599			
2029-30							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
7	Kalam Asrit	Hydro	238	238	PEDO	Optimized	Jul-29
8	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
9	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
10	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
15	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
16	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			2,096	2,096			
Cumulative Addition up till 2030 (MW)			32,018	31,694			
2030-31							
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
Generation Additions in 2030-31 (MW)			3,549	3,549			
Cumulative Addition up till 2031 (MW)			35,567	35,243			

Note: Solar values are in MW_p

6.5. Annual Capacity Factors

The annual capacity factors information based on the Installed Capacity for the corresponding year, as shows in the Table 6-4.

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

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.33	6.25	6.23	5.95	5.90
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.86	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.28	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.80	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.69	55.78
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.76	54.76	54.79

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
80	Chowkel Khwar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	44.57	44.57	44.57
81	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
82	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
83	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
84	Kalam Asrit	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.41	44.41
85	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
86	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
87	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
88	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
89	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94
90	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
91	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
92	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.30
93	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.85	51.90
94	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	54.06	52.77
95	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
96	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
97	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
98	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.83	42.83	42.83
99	Jagran-II	HPP Committed	50.53	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
100	Karot	HPP Existing	44.39	44.29	44.39	44.39	44.39	44.29	44.38	44.38	44.39
101	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
102	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
103	Koto	HPP Committed	57.12	57.08	57.24	57.19	57.19	56.96	57.12	57.12	57.19
104	Lawi	HPP Committed	0.00	47.99	48.10	48.05	48.05	47.90	47.99	47.99	48.02
105	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
106	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	46.36	42.60	42.71	42.71	42.71
107	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
108	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
109	Chamfall	HPP Committed	0.00	49.12	49.12	49.12	49.12	48.99	49.12	49.12	49.12
110	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.62	73.66	73.57	73.62	73.62	73.66
111	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
112	Deg Outfall	HPP Committed	76.26	76.09	76.29	76.29	76.29	76.09	76.29	76.29	76.29
113	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
114	Karora	HPP Committed	67.48	67.57	67.62	67.55	67.55	67.42	67.48	67.48	67.55
115	Kathai-II	HPP Committed	0.00	0.00	60.37	60.37	60.37	60.21	60.37	60.37	60.37
116	Kurram Tangi	HPP Committed	0.00	17.05	17.05	17.05	17.05	17.01	17.05	17.05	17.05
117	Riali-II	HPP Committed	0.00	53.15	53.17	53.16	53.16	53.01	53.15	53.15	53.16
118	Allai Khwar	HPP Existing	44.32	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
119	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
120	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
121	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
122	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
123	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
124	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
125	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
126	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
127	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
128	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
129	Mangla	HPP Existing	64.94	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
130	Neelum Jehlum	HPP Existing	51.68	51.54	51.69	51.69	51.69	51.54	51.69	51.69	51.69
131	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
132	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
133	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
134	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
135	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
136	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
137	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.73	70.05	35.76	32.36	31.19	27.38
138	Foundation	CCGT_Gas	89.97	90.25	90.00	89.97	82.20	57.94	80.45	82.62	81.85
139	Guddu-I	CCGT_Gas	36.90	74.63	74.43	74.42	69.00	61.74	71.52	68.65	68.12
140	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
141	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	73.83	73.02	72.94	70.20	69.68
142	Liberty	CCGT_Gas	74.86	75.02	46.06	50.52	0.00	0.00	0.00	0.00	0.00
143	Uch	CCGT_Gas	86.08	86.32	86.08	85.47	77.52	43.54	45.27	53.03	0.00
144	Uch-II	CCGT_Gas	87.77	88.05	87.81	87.35	79.29	51.33	51.33	77.18	51.32
145	SNPC-I	KE_CCGT_Gas	91.98	92.25	91.96	91.81	83.75	35.08	79.67	85.56	55.81
146	SNPC-II	KE_CCGT_Gas	91.98	92.25	91.96	91.98	84.04	36.91	79.88	85.56	84.71
147	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
158	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
159	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
160	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
161	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
164	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
165	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
166	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
167	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
168	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
169	K-2	Nuclear	85.06	85.30	85.07	85.06	85.06	85.29	85.05	85.05	85.05
170	K-3	Nuclear	85.66	85.90	85.67	85.66	85.66	85.89	85.65	85.65	85.65
171	Engro Thar	Local Coal	82.51	82.74	82.51	82.50	82.07	80.80	80.65	81.58	78.14
172	Gwadar	Local Coal	0.00	0.00	0.00	69.18	82.41	80.69	80.74	80.91	78.54
173	Lucky	Local Coal	85.08	85.31	85.08	85.07	85.07	85.31	85.01	85.07	85.07
174	Thal Nova	Local Coal	49.35	85.21	84.98	84.97	84.97	84.61	83.85	84.38	83.74
175	Thar TEL	Local Coal	84.98	85.21	84.98	84.97	84.96	84.44	84.08	84.24	83.11
176	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	84.61	84.33	84.41	84.47
177	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.33	83.20	82.90	83.19	83.33
178	China HUBCO	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
179	Jamshoro Coal	Imported Coal	49.36	84.04	83.89	80.49	28.39	16.46	19.90	23.39	22.31
180	Port Qasim	Imported Coal	50.02	50.02	50.02	50.02	50.02	50.02	50.02	50.02	50.02
181	Sahiwal Coal	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
182	FPCL	KE_Imported Coal	82.15	77.13	18.09	18.37	10.94	10.14	14.34	14.30	13.87
183	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
184	Balloki	CCGT_RLNG	4.19	2.02	0.96	1.80	2.01	0.64	1.28	1.23	1.14
185	Bhikki	CCGT_RLNG	1.20	0.78	0.00	0.52	0.57	0.29	0.43	0.57	0.54
186	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
187	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.00	0.30	0.30	0.30
188	Haveli	CCGT_RLNG	10.92	5.77	3.29	5.01	4.09	1.59	1.87	1.91	2.26
189	KAPCO 1	CCGT_RLNG	35.31	35.38	35.25	0.00	0.00	0.00	0.00	0.00	0.00
190	KAPCO 2	CCGT_RLNG	11.86	11.83	11.89	0.00	0.00	0.00	0.00	0.00	0.00
191	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.23	0.26
193	Orient	CCGT_RLNG	37.73	23.25	0.00	0.00	0.30	0.00	0.30	0.30	0.30
194	Rousch	CCGT_RLNG	0.24	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
195	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.30	0.30
196	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.13	0.00	0.28	0.30	0.30
197	Trimmu	CCGT_RLNG	26.05	20.80	12.24	11.65	8.20	3.37	5.45	6.81	6.96
198	BQPS2	KE_CCGT_RLNG	85.21	83.46	29.63	25.80	15.75	8.92	13.30	13.97	14.11
199	BQPS3	KE_CCGT_RLNG	89.81	89.80	79.57	82.91	28.60	19.19	21.26	24.10	22.99
200	KCCPP	KE_CCGT_RLNG	85.10	82.46	22.09	18.23	11.20	7.83	9.78	12.79	11.87
201	KTGTPS	KE_CCGT_RLNG	45.16	40.73	8.23	9.95	6.21	2.90	3.92	5.12	5.99
202	SGTPS	KE_CCGT_RLNG	48.00	44.44	9.14	10.60	6.68	3.16	4.17	5.44	7.26
203	BQPS1-U1	KE_ST_RLNG	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
204	BQPS1-U5	KE_ST_RLNG	29.34	30.27	1.66	1.71	0.46	0.75	1.00	1.05	1.39
205	BQPS1-U6	KE_ST_RLNG	16.15	15.84	1.43	1.54	0.30	0.01	0.63	0.75	0.96

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
206	BQPS1-U2	KE_GT_RLNG	22.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: (All numbers highlighted in yellow color, in this table, represent retirement of the corresponding project.)

6.6. 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 (Million US$)

FY	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
2023	1,797	7,513	9,310	9,310
2024	1,898	6,570	8,468	17,779
2025	2,070	4,780	6,851	24,629
2026	2,077	3,994	6,070	30,699
2027	2,114	2,974	5,088	35,787
2028	2,191	2,456	4,647	40,434
2029	2,088	2,320	4,408	44,842
2030	2,021	2,173	4,194	49,036
2031	2,017	1,935	3,952	52,988

Table 6-6: Year wise Un-Discounted Cost (Million US$)

FY	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
2023	1,797	7,513	9,310	9,310
2024	2,088	7,227	9,315	18,625
2025	2,505	5,784	8,289	26,915
2026	2,764	5,315	8,079	34,994
2027	3,095	4,354	7,449	42,443
2028	3,529	3,955	7,484	49,927
2029	3,699	4,110	7,809	57,736
2030	3,939	4,234	8,173	65,909
2031	4,323	4,149	8,471	74,380

6.7. Salient Features of the IGCEP

In order to balance a projected peak load of 41,338 MW by the year 2030-31, the PLEXOS model proposes 68,667 MW of installed generation capacity; salient features of the study are as follows:

a. Significant Induction of VREs (clean and indigenous)
b. Substantial utilization of hydro-based power
c. Induction of indigenous coal-based power
d. Balancing the overall basket price with increased share of hydro power and REs
e. Optimal indigenization: less reliance on imported fuel i.e., Imported Coal, RFO, RLNG etc.
f. Substantial reduction in carbon emissions owing to induction of REs and hydro
g. All optimized generation projects are indigenous without any imported fuel

Meanwhile, a capacity of 8,021 MW is meant to be retired by the year 2030-31. In order to provide a quick understanding of the generation mix of the IGCEP 2022-31, the report includes the Table 6-7 which highlights addition and retirement of different types of generation capacities. Moreover, fuel-wise capacity in megawatts, energy in GWh and their monthly share in the total generated energy, over the period of this plan, which are further illustrated by the Chart 6-4 through 6-6, Chart 6-7 through 6-9 and Chart 6-10 through 6-11 respectively.

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

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
Jun-22	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	3,120	-	-	-	2,773	55,482
2027	990	2,558	-	-	-	1,664	-225	-1,292	-	3,695	59,177
2028	-	545	-	-	-	3,464	-	-131	-	3,878	63,055
2029	-	886	-	-	-	1,153	-	-727	-	1,312	64,366
2030	-	1,526	-172	-	-	570	-	-136	-	1,788	66,154
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	68,667
Total	4,590	22,701	8,710	3,620	4,680	20,086	1,933	1,347	1,000	68,667	

6.8. Comparison of Scenarios

In addition to the base case, six scenarios have been developed to facilitate the decision makers to reach an informed decision. Scenario-I and Scenario-II comprise of Low Demand Forecast (Average GDP GR 3.40%) and High Demand Forecast (Average GDP GR 5.42%) respectively, as compared to base case demand (Average GDP GR 4.30%), whereas, Scenario-III, Scenario-IV, Scenario-V and Scenario-VI have base case demand along with Diamer Bhasha HPP in 2029, Chashma Nuclear (C-5) in 2029, 1,320 MW local coal-based power projects in 2027 & 2030 each year and VRE unconstrained, respectively.

The results show that base case has optimized capacity addition of 8,564 MW_p of solar PV (includes utility scale and feeder based/DG), 4,827 MW wind, 3,588 MW hydro and 990 MW local coal, throughout the study horizon. In Scenario-I (Low Demand), the optimization decreases candidate solar PV, wind and hydro by 2,664 MW_p, 724 MW, 298 MW respectively as compared to the base case by the year 2030-31. In Scenario-II (High Demand), apart from base case additions, the optimization increases candidate solar PV, wind, hydro, local coal and imported coal by 578 MW_p, 2400 MW, 340 MW, 990 MW and 660 MW respectively.

For Scenario-III (Diamer Bhasha HPP in 2029), 4,171 MW more hydro is inducted in the system, whereas, the optimization decreases candidate solar and wind by 320 MW_p and 603 MW respectively as compared to the base case by the year 2030-31. In Scenario-IV (Chashma Nuclear C-5 for Energy Security), the optimization decreases candidate solar PV and hydro by 194 MW_p and 298 MW respectively due to induction of 1,200 MW NPP, whereas it also increases the wind capacity by 468 MW, as compared to the base case by the year 2030-31. In Scenario-V (1,320 MW Local coal inclusion in 2027 & 2030), the optimization decreases candidate solar PV, wind and hydro by 2,394 MW_p, 931 MW of 298 MW respectively as compared to the base case by the year 2030-31. Finally in Scenario-VI (Unconstrained VRE), the optimization decreases solar PV by 811 MW_p whereas it increases the wind capacity by 1,091 MW, as compared to the base case.

A comparison of CODs for all the candidate projects (HPPs and thermal) optimized by the tool for the base case along with scenarios mentioned above is given in Annexure B-6.

The installed capacities for base case and all the scenarios for the year 2030-31 are summarized in Table 6-8.

Table 6-8: Scenario-wise Installed Capacity (MW) by 2030-31

Category	Base	Low Demand	High Demand	Diamer Bhasha HPP in 2029	Chashma Nuclear (C-5) for Energy Security	1,320 MW Local Coal inclusion in 2027 & 2030	Un-constrained VRE
Imported Coal	4,680	4,680	5,340	4,680	4,680	4,680	4,680
Local Coal	4,590	4,590	5,580	4,590	4,590	7,230	4,590
RLNG	8,710	8,710	8,710	8,710	8,710	8,710	8,710
Gas	1,933	1,933	1,933	1,933	1,933	1,933	1,933
Nuclear	3,620	3,620	3,620	3,620	4,820	3,620	3,620
Bagasse	394	394	394	394	394	394	394
Solar PV	12,926	10,262	13,504	12,606	12,732	10,532	12,115
HPP	22,701	22,403	23,041	26,871	22,403	22,403	22,701
Cross Border	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Wind	6,767	5,693	8,817	5,814	6,885	5,836	7,508
RFO	1,347	1,347	1,347	1,347	1,347	1,347	1,347
Total (MW)	**68,667**	**64,631**	**73,285**	**71,565**	**69,493**	**67,684**	**68,597**

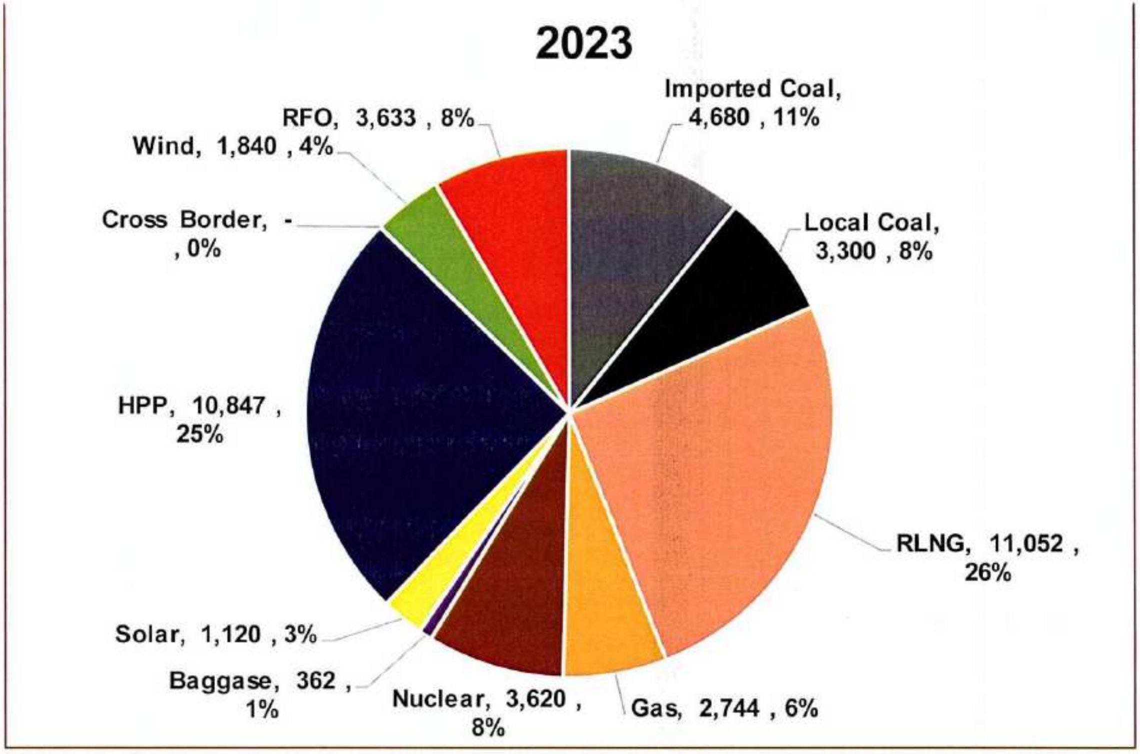


Chart 6-4: IGCEP Generation Mix 2023 (43,198 MW)

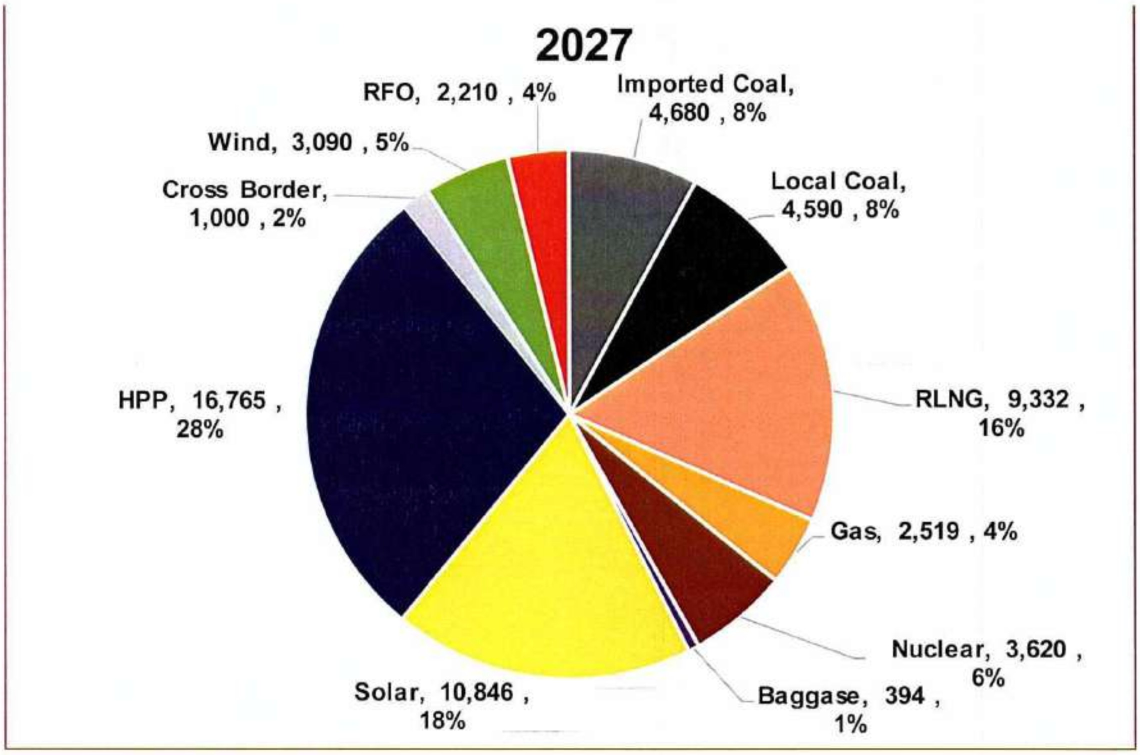


Chart 6-5: IGCEP Generation Mix 2027 (59,046 MW)

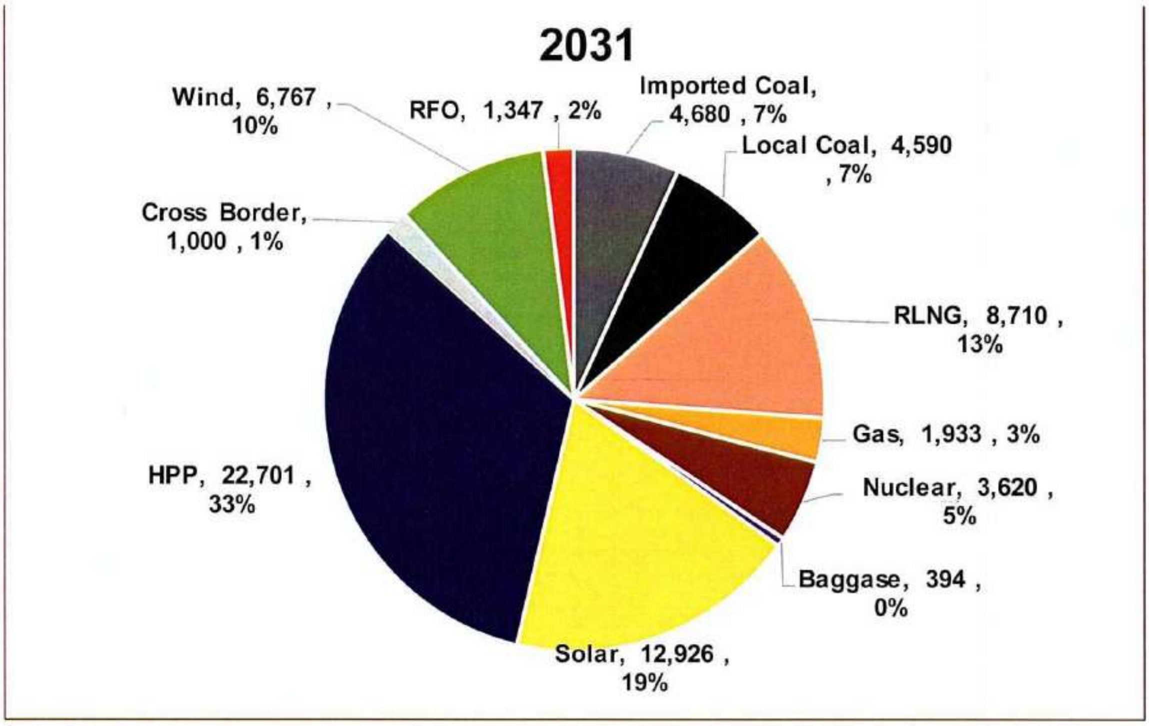


Chart 6-6: IGCEP Generation Mix 2031 (68,667 MW)

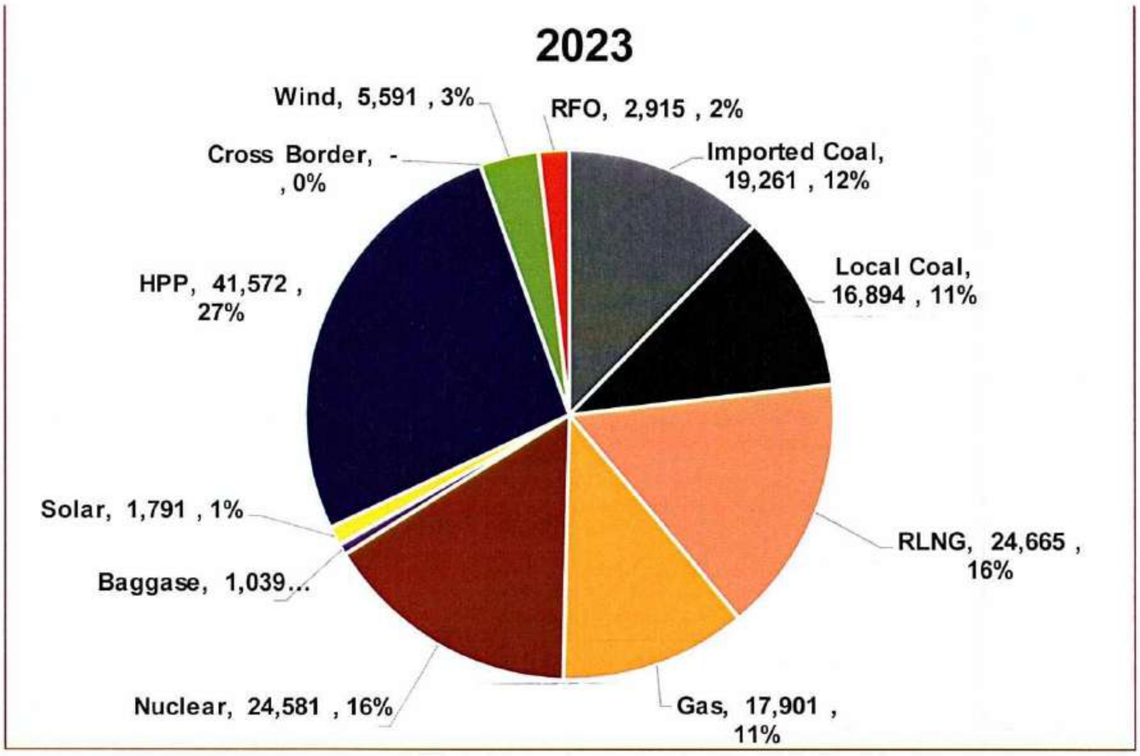


Chart 6-7: IGCEP Generation Mix 2023 (156,210 GWh)

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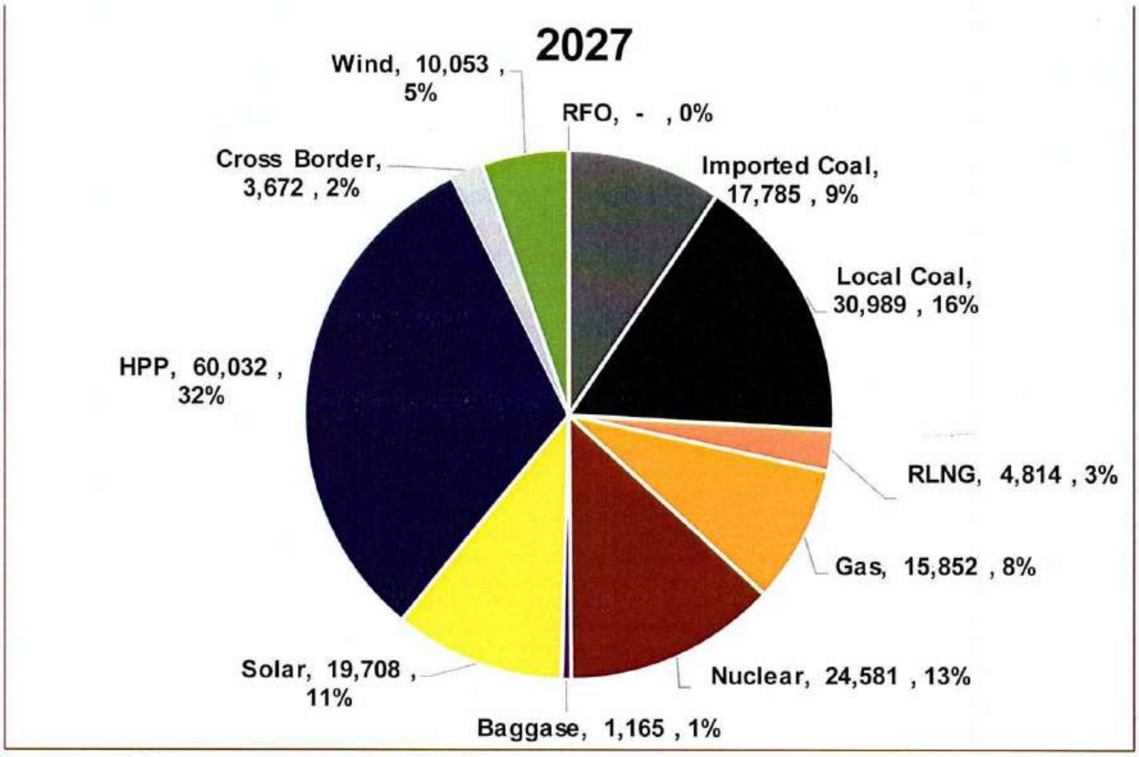


Chart 6-8: IGCEP Generation Mix 2027 (188,651 GWh)

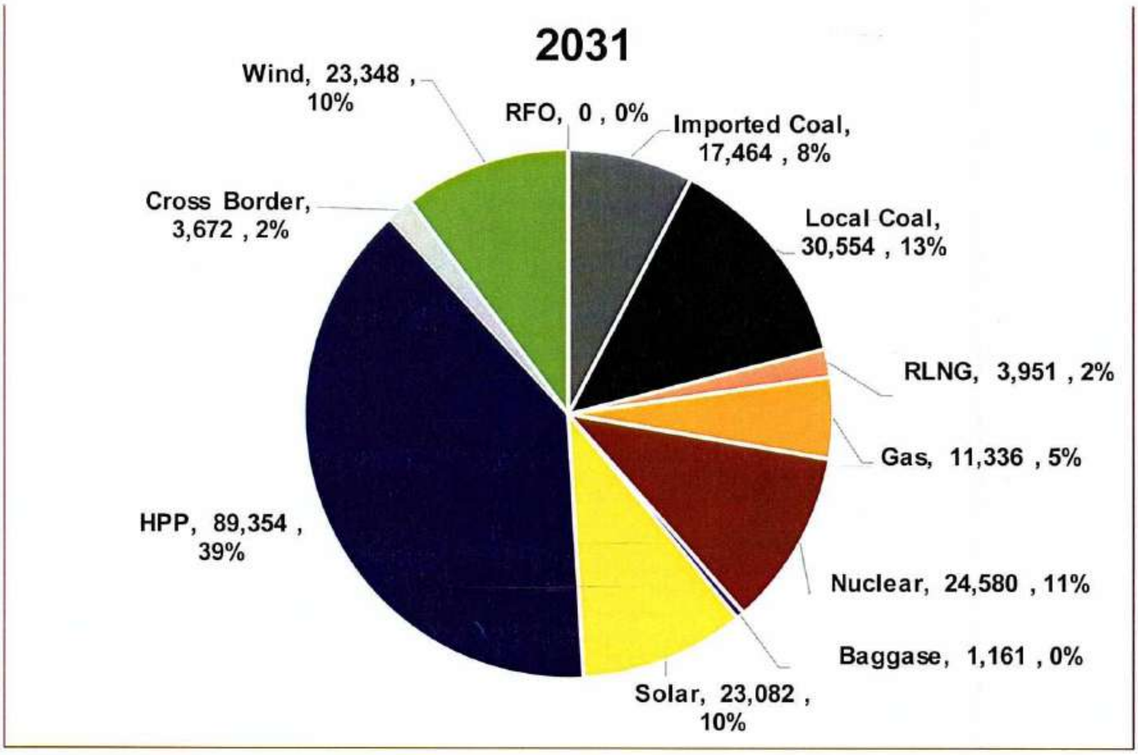


Chart 6-9: IGCEP Generation Mix 2031 (228,501 GWh)

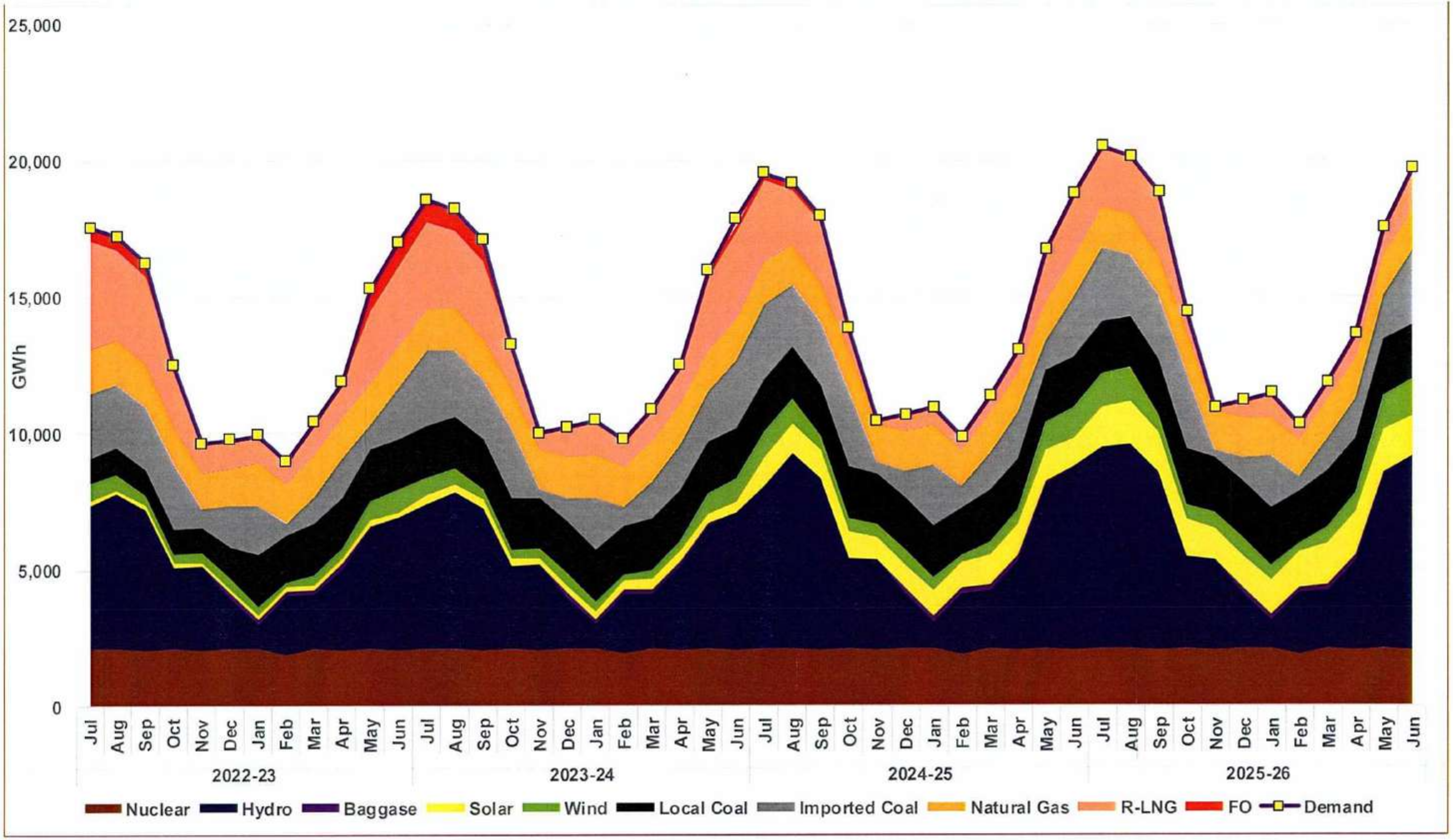


Chart 6-10: IGCEP Monthly Generation Mix 2023-26 (GWh)

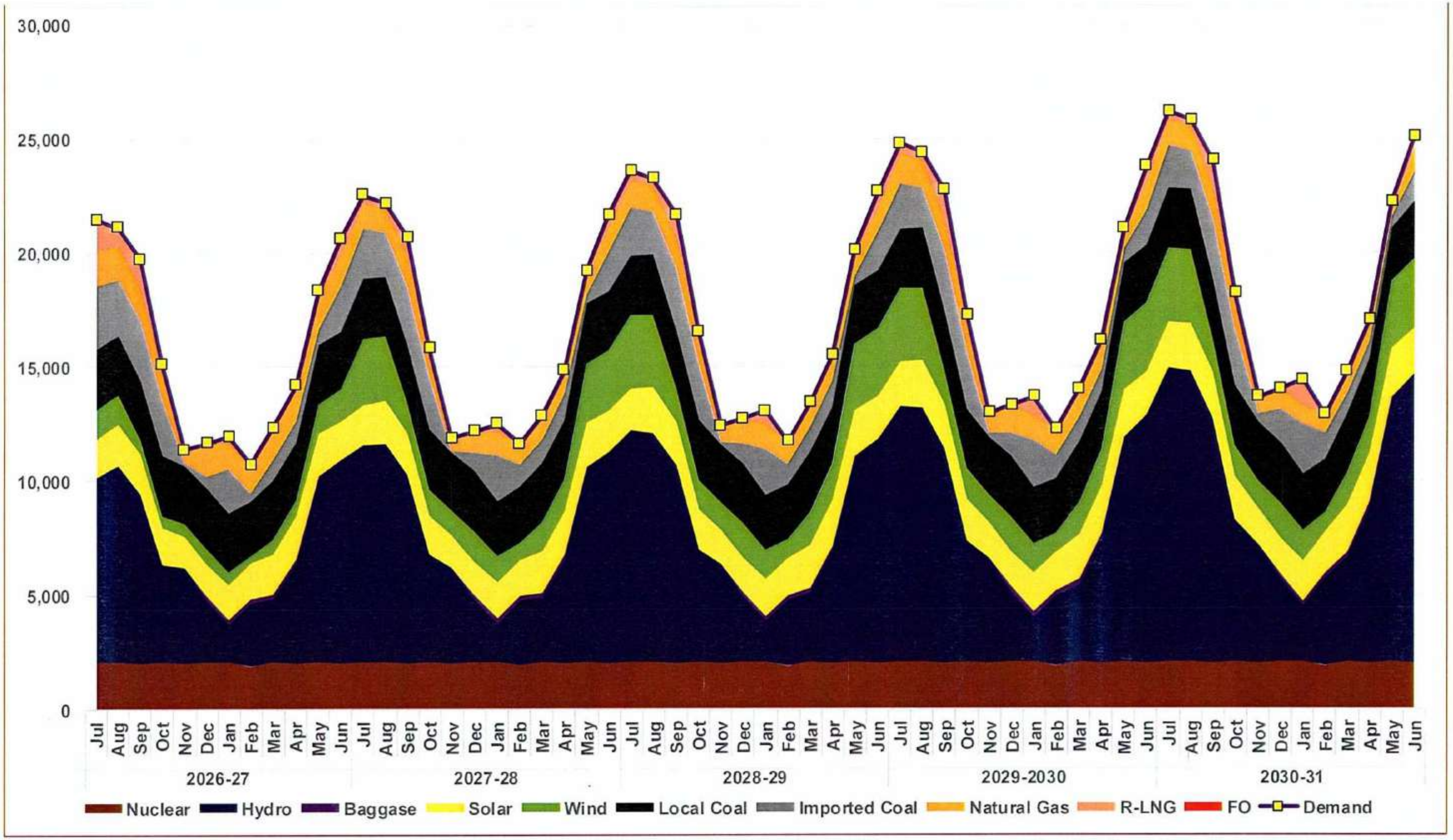


Chart 6-11: IGCEP Monthly Generation Mix 2027-31 (GWh)

6.9. 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 PSP Team is more than willing to discuss and incorporate further suggestions from the stakeholders to shape it into a meaningful output. As per PC-4 of the prevailing Grid Code, NEPRA will review and approve the IGCEP. All kind of suggestions, comments and concerns are most welcome at **comments.igcep@ntdc.com.pk**; **+92-42-99200695**. For wider dissemination and seeking generous feedback, the IGCEP 2022-31 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 Proposed Actions for the Future Generation Plans

a. More options for Demand Side Management (DSM) other than energy efficiency targets, provided by NEECA for the IGCEP 2022-31, shall be explored for 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. 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.

d. 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 energy.

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 project will need to be carried out by the stakeholders.

b. The combination of wind and solar PV 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. The relevant project execution agencies should provide data hybrid RE technologies.

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 dispatch of renewable energy.

7.2.2 Operational Challenges and Solutions for VRE Integration

System operational performance and grid flexibility studies are required to be carried out for VRE intermittency management to ensure its optimal region wise penetration by considering ramping up/down capability by synchronous generators in the system and FACTS / BESS applications. The quantum and/or timelines of wind and solar may vary in future as a result of these studies.

In order to utilize huge renewable resource potential of Pakistan in a sustainable manner, the VRE 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 & regulation and maintaining the reactive power balance.
c. Reserve power even when the renewable resource is not available.

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

7.3 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 expected to be 20.6 MT/annum. (Source: Engro report).

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 authenticity 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.

7.4 Tapping Nuclear Potential

Sustainability of generation is a key factor in power system planning. Nuclear generation is a sustainable energy resource and is also important to mitigate the climate change issues. The nuclear power project is of base load nature, have higher capital cost but lower operational cost with much longer life as compared to other baseload project. Nuclear generation is a very reliable source of energy all around the year especially during low / lean hydro months in Pakistan. Moreover, the addition of nuclear power Project can diversify energy mix of the country in years to come. The location of the potential nuclear power project at Chashma is near northern/mid-country load centers, thus requiring relatively lower transmission evacuation infrastructure as compared to the remotely located baseload power projects.

Therefore, there is a need to compare the viability of the nuclear power project with other indigenous baseload power projects by considering their respective generation and transmission evacuation costs.

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. 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.

ANNEXURES
(A – H)

Annexure A. Load Forecast Data

A-1. Projected GDP Growth Rate by Sector - Normal Scenario

FY	GDP Growth Rate (%)			
	Total	Commercial	Industrial	Agriculture
2022	5.97	7.18	8.39	3.75
2023	4.41	5.88	6.53	2.58
2024	4.46	4.23	6.36	2.76
2025	4.36	4.29	5.06	3.26
2026	4.06	4.42	5.56	2.46
2027	3.86	3.97	4.86	2.66
2028	4.16	3.82	5.36	2.86
2029	3.96	4.07	5.26	2.76
2030	3.76	3.80	4.56	2.76
2031	4.06	3.72	4.86	2.86

A-2. Projected GDP Growth Rate by Sector - Low Scenario

FY	GDP Growth Rate (%)			
	Total	Commercial	Industrial	Agriculture
2022	5.97	7.18	8.39	3.75
2023	3.41	5.88	5.53	1.58
2024	3.46	3.23	5.36	1.76
2025	3.36	3.29	4.06	2.26
2026	3.06	3.42	4.56	1.46
2027	2.86	2.97	3.86	1.66
2028	3.16	2.82	4.36	1.86
2029	2.96	3.07	4.26	1.76
2030	2.76	2.80	3.56	1.76
2031	3.06	2.72	3.86	1.86

A-3. Projected GDP Growth Rate by Sector - High Scenario

FY	GDP Growth Rate (%)			
	Total	Commercial	Industrial	Agriculture
2022	5.97	7.18	8.39	3.75
2023	5.66	5.63	7.77	3.83
2024	5.70	5.60	7.60	4.00
2025	5.60	5.60	6.30	4.50
2026	5.30	5.30	6.80	3.70
2027	5.10	5.10	6.10	3.90
2028	5.40	5.30	6.60	4.10
2029	5.20	5.10	6.50	4.00
2030	5.00	5.10	5.80	4.00
2031	5.30	5.30	6.10	4.10

A-4. Historical GDP at constant cost factor 2015-16, Consumer Price Index

FY	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Commercial	Industrial	Agriculture		
	(Rs. Million)					
1970	3,477,476	1,517,378	477,776	1,729,191	1.68	-
1971	3,520,384	1,556,098	508,239	1,676,108	1.80	7.40%
1972	3,602,006	1,611,306	500,689	1,734,279	2.01	11.40%
1973	3,846,978	1,766,671	552,502	1,763,158	2.30	14.60%
1974	4,133,676	1,939,625	598,978	1,836,870	2.90	26.30%
1975	4,294,016	2,134,321	610,694	1,797,951	3.56	22.60%
1976	4,433,709	2,165,345	640,637	1,878,401	3.77	5.90%
1977	4,559,744	2,230,936	659,513	1,925,846	4.11	9.00%
1978	4,912,256	2,465,328	722,262	1,980,167	4.40	7.20%
1979	5,183,791	2,615,929	777,330	2,041,501	4.81	9.30%
1980	5,563,617	2,770,440	861,038	2,176,410	5.35	11.20%

h

FY	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Commercial	Industrial	Agriculture		
	(Rs. Million)					
1981	5,919,785	2,952,677	941,818	2,256,034	6.15	15.00%
1982	6,367,416	3,185,884	1,042,956	2,362,607	6.63	7.80%
1983	6,799,664	3,480,310	1,094,458	2,466,669	7.10	7.00%
1984	7,069,819	3,755,140	1,171,753	2,347,665	7.57	6.70%
1985	7,685,466	4,052,662	1,263,542	2,604,130	8.16	7.80%
1986	8,174,492	4,286,484	1,365,891	2,759,042	8.44	3.50%
1987	8,649,496	4,537,778	1,483,977	2,848,812	8.92	5.60%
1988	9,206,192	4,844,842	1,629,723	2,926,623	9.57	7.40%
1989	9,648,855	5,029,418	1,705,522	3,127,690	10.35	8.10%
1990	10,091,613	5,254,644	1,815,185	3,222,480	11.29	9.10%
1991	10,653,444	5,528,425	1,939,678	3,382,383	12.72	12.60%
1992	11,475,327	5,902,079	2,089,644	3,703,754	13.91	9.40%
1993	11,735,975	6,175,579	2,204,839	3,507,972	15.18	9.10%
1994	12,268,880	6,435,085	2,304,984	3,691,351	16.99	11.90%
1995	12,775,892	6,743,837	2,320,908	3,933,790	19.05	12.10%
1996	13,618,986	7,080,474	2,430,537	4,394,954	21.01	10.30%
1997	13,850,875	7,336,143	2,422,634	4,400,387	23.63	12.50%
1998	14,334,813	7,456,814	2,570,784	4,599,181	25.16	6.50%
1999	14,934,552	7,829,010	2,697,295	4,688,803	26.09	3.70%
2000	15,517,929	8,154,084	2,731,596	4,974,532	27.42	5.10%
2001	15,823,202	8,406,031	2,844,471	4,866,220	28.11	2.50%
2002	16,315,604	8,806,394	2,921,215	4,871,251	29.16	3.70%
2003	17,086,643	9,265,776	3,044,976	5,073,273	29.72	1.90%
2004	18,365,293	9,806,968	3,540,180	5,196,531	32.23	8.50%
2005	20,010,403	10,639,778	3,969,088	5,533,564	35.05	8.70%

FY	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Commercial	Industrial	Agriculture		
	(Rs. Million)					
2006	21,174,660	11,329,945	4,132,022	5,882,009	37.73	7.60%
2007	22,347,017	11,962,655	4,451,424	6,083,380	40.37	7.00%
2008	23,461,708	12,553,428	4,828,575	6,193,327	35.05	-13.20%
2009	23,546,340	12,720,576	4,577,158	6,409,945	37.73	7.60%
2010	24,153,955	13,128,428	4,733,888	6,424,659	40.37	7.00%
2011	25,029,238	13,645,735	4,947,262	6,550,711	71.85	78.00%
2012	25,989,532	14,245,756	5,073,292	6,787,987	79.76	11.00%
2013	26,946,755	14,977,029	5,111,364	6,969,568	85.63	7.40%
2014	28,039,002	15,644,927	5,342,921	7,143,565	93.01	8.60%
2015	29,176,784	16,327,237	5,619,686	7,295,725	97.22	4.50%
2016	30,508,205	17,261,613	5,939,636	7,306,957	100.00	2.90%
2017	31,914,207	18,232,012	6,213,295	7,468,900	104.81	4.80%
2018	33,859,620	19,317,324	6,783,864	7,758,432	109.72	4.70%
2019	34,916,041	20,284,070	6,800,675	7,831,296	117.18	6.80%
2020	34,586,665	20,038,838	6,409,966	8,137,860	129.76	10.70%
2021	36,572,644	21,241,331	6,910,607	8,420,705	140.56	8.30%
2022	38,755,090	22,555,934	7,407,709	8,791,447	156.08	11.04%

A-5. Category-wise Nominal Tariff

Nominal Tariff (Excluding K Electric) (Rs/kWh)									
Year	**Dom**	**Com**	**Ind**	**Agr**	**Year**	**Dom**	**Com**	**Ind**	**Agr**
1973	0.20	0.27	0.14	0.10	**1998**	1.85	6.55	4.11	1.87
1974	0.20	0.32	0.18	0.11	**1999**	2.35	7.18	4.48	2.33
1975	0.21	0.36	0.21	0.12	**2000**	2.33	7.04	4.16	2.31
1976	0.23	0.46	0.28	0.16	**2001**	2.59	7.04	4.16	2.58
1977	0.25	0.53	0.34	0.16	**2002**	3.18	7.08	4.19	2.93
1978	0.24	0.60	0.37	0.14	**2003**	3.34	7.03	4.42	3.33
1979	0.29	0.72	0.46	0.21	**2004**	4.34	6.85	4.46	3.51
1980	0.35	0.95	0.57	0.28	**2005**	3.40	6.60	4.25	3.49
1981	0.40	1.00	0.63	0.32	**2006**	3.68	8.07	5.09	3.57
1982	0.42	1.08	0.68	0.36	**2007**	3.76	8.21	5.17	3.64
1983	0.43	1.18	0.76	0.38	**2008**	4.36	10.10	6.56	3.55
1984	0.44	1.21	0.76	0.43	**2009**	5.40	11.54	7.48	5.02
1985	0.44	1.23	0.78	0.38	**2010**	6.54	13.24	8.94	6.15
1986	0.49	1.43	0.92	0.43	**2011**	7.31	14.90	9.60	7.99
1987	0.48	1.40	0.89	0.37	**2012**	8.41	16.64	10.90	9.35
1988	0.52	1.71	1.11	0.40	**2013**	8.83	17.87	12.18	11.38
1989	0.62	2.13	1.33	0.46	**2014**	9.48	21.27	15.83	12.02
1990	0.66	2.46	1.50	0.55	**2015**	10.22	22.24	15.39	14.00
1991	0.76	2.76	1.66	0.57	**2016**	10.48	20.17	13.75	12.66
1992	0.81	3.16	1.89	0.63	**2017**	10.65	20.22	14.12	10.64
1993	0.84	3.31	1.99	0.66	**2018**	11.14	21.04	14.92	11.25
1994	0.96	3.86	2.29	0.74	**2019**	12.86	26.12	18.23	11.29
1995	1.10	4.27	2.68	0.94	**2020**	13.62	29.77	23.18	10.60
1996	1.36	5.37	3.36	1.31	**2021**	14.29	31.10	22.48	13.65
1997	1.56	5.66	3.75	1.63	**2022**	18.52	36.99	28.23	16.84

A-6. Category-wise Real Tariff

Real Tariff (Excluding K Electric) (Rs/kWh)									
Year	**Dom**	**Com**	**Ind**	**Agr**	**Year**	**Dom**	**Com**	**Ind**	**Agr**
1973	8.58	11.56	6.23	4.33	**1998**	7.36	26.03	16.33	7.43
1974	6.85	10.96	6.07	3.69	**1999**	9.00	27.53	17.19	8.95
1975	5.88	10.16	5.97	3.37	**2000**	8.51	25.66	15.18	8.43
1976	6.11	12.33	7.47	4.12	**2001**	9.21	25.03	14.79	9.17
1977	6.09	13.01	8.17	3.83	**2002**	10.92	24.29	14.36	10.04
1978	5.50	13.55	8.50	3.26	**2003**	11.24	23.65	14.87	11.20
1979	5.93	14.90	9.61	4.37	**2004**	13.46	21.25	13.84	10.89
1980	6.46	17.69	10.68	5.32	**2005**	9.70	18.83	12.13	9.96
1981	6.43	16.26	10.26	5.23	**2006**	9.75	21.39	13.49	9.46
1982	6.28	16.25	10.20	5.41	**2007**	9.31	20.34	12.81	9.02
1983	6.10	16.62	10.65	5.41	**2008**	12.43	28.83	18.72	10.14
1984	5.79	16.02	10.10	5.63	**2009**	14.32	30.58	19.83	13.32
1985	5.38	15.03	9.62	4.70	**2010**	16.21	32.79	22.14	15.23
1986	5.86	16.92	10.89	5.12	**2011**	10.18	20.74	13.36	11.11
1987	5.33	15.66	10.00	4.13	**2012**	10.55	20.87	13.66	11.72
1988	5.46	17.89	11.61	4.17	**2013**	10.31	20.87	14.22	13.29
1989	6.01	20.62	12.85	4.42	**2014**	10.19	22.87	17.02	12.92
1990	5.85	21.78	13.31	4.83	**2015**	10.51	22.88	15.83	14.40
1991	5.98	21.73	13.02	4.44	**2016**	10.48	20.17	13.75	12.66
1992	5.79	22.68	13.57	4.54	**2017**	10.16	19.29	13.47	10.16
1993	5.54	21.81	13.10	4.36	**2018**	10.15	19.18	13.60	10.25
1994	5.65	22.69	13.48	4.34	**2019**	10.97	22.29	15.56	9.63
1995	5.79	22.43	14.08	4.91	**2020**	10.50	22.94	17.86	8.17
1996	6.48	25.56	16.00	6.22	**2021**	10.17	22.13	15.99	9.71
1997	6.59	23.93	15.85	6.90	**2022**	11.87	23.70	18.09	10.79

A-7. Category-wise Electricity Consumption (Excluding K Electric)-GWh

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

Year	Dom	Com	Ind	Agr	Street-Light	Bulk	Others	Total
1997	15,594	1,757	10,115	7,018	308	2,485	19	38,529
1998	16,367	1,768	10,238	6,888	307	2,694	16	39,422
1999	16,927	1,825	9,945	5,575	159	2,646	15	38,900
2000	18,942	2,003	10,773	4,512	150	2,676	15	40,910
2001	20,019	2,120	11,744	4,896	146	2,634	14	43,384
2002	20,549	2,285	12,637	5,582	149	2,662	12	45,204
2003	20,855	2,516	13,462	5,986	166	2,626	10	47,421
2004	22,668	2,884	14,476	6,624	192	2,796	9	51,492
2005	24,049	3,192	15,568	6,921	227	2,892	12	55,278
2006	27,009	3,768	16,596	7,873	279	3,031	13	62,405
2007	28,944	4,289	17,603	8,097	316	3,252	13	67,419
2008	28,711	4,358	17,299	8,380	340	3,319	11	66,489
2009	27,755	4,203	16,035	8,695	347	3,188	10	65,248
2010	29,479	4,465	16,372	9,585	371	3,357	10	68,847
2011	30,972	4,683	17,700	8,847	374	3,607	10	71,642
2012	30,365	4,563	18,403	8,414	360	3,509	43	71,341
2013	30,329	4,435	18,636	7,548	351	3,659	60	70,481
2014	33,325	4,795	20,550	8,130	351	3,872	32	76,496
2015	34,567	4,853	21,086	7,866	330	3,909	33	78,071
2016	37,123	5,417	21,150	8,364	295	4,239	34	81,682
2017	41,412	6,114	20,067	9,063	298	4,566	31	86,628
2018	46,114	6,753	23,274	9,978	319	5,014	450	97,030
2019	45,590	6,629	24,285	9,676	291	5,082	2,335	98,844
2020	47,643	6,260	21,489	9,642	273	4,887	2,597	98,197
2021	49,814	6,688	24,663	10,116	314	4,973	2,802	99,370
2022	52,407	7,387	28,115	5,382	10,922	347	3,306	107,866

A-8. Category-wise Number of Consumers (Excluding K Electric)

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

Year	Dom	Com	Ind	Agr	Street Light	Bulk & Others	Total
2001	10,045,035	1,737,199	195,511	180,411	4,993	3,195	12,166,344
2002	10,482,804	1,803,132	199,839	184,032	4,854	3,361	12,678,022
2003	11,043,530	1,867,226	206,336	191,961	5,441	3,739	13,318,233
2004	11,737,078	1,935,462	210,296	198,829	5,800	3,873	14,091,338
2005	12,490,189	1,983,216	212,233	200,756	6,171	3,677	14,896,242
2006	13,389,762	2,068,312	222,283	220,501	6,550	3,753	15,911,161
2007	14,354,365	2,151,971	233,162	236,255	6,990	3,811	16,986,554
2008	15,226,711	2,229,403	242,401	245,640	7,337	3,874	17,955,366
2009	15,859,373	2,291,628	253,089	258,368	7,680	3,976	18,674,114
2010	16,673,015	2,362,312	263,507	271,268	8,034	4,088	19,582,224
2011	17,322,140	2,421,221	273,067	280,603	8,386	4,066	20,309,483
2012	17,978,395	2,482,702	286,401	286,287	8,698	4,128	21,046,611
2013	18,713,537	2,550,808	296,849	301,115	9,107	4,184	21,875,600
2014	19,323,307	2,635,086	305,294	310,578	9,369	4,236	22,587,870
2015	20,148,495	2,723,708	315,116	318,081	9,554	4,293	23,519,247
2016	21,040,707	2,814,234	325,816	321,055	9,857	5,030	24,516,699
2017	21,991,479	2,905,517	336,045	323,524	10,124	5,114	25,571,803
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
2022	28,743,039	3,475,468	367,736	369,356	11,807	222,390	33,189,796

Annexure B. Generation Planning Data

B-1(i). NTDC Existing Installed Capacity (As of June 2022)

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable 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	1,140	1,140
9	Neelum Jehlum	Hydro	969	969
11	Tarbela 1-14	Hydro	3,478	3,478
12	Tarbela_Ext_04	Hydro	1,410	1,410
13	Warsak	Hydro	243	243
Small Hydel				
14	Gomal Zam	Hydro	17	17
15	Rasul	Hydro	22	22
16	Dargai	Hydro	20	20
17	Nandipur	Hydro	14	14
18	Shadiwal	Hydro	14	14
19	Chichoki	Hydro	13	13
20	Kurram Garhi	Hydro	4	4
21	Renala	Hydro	1	1
22	Chitral	Hydro	1	1
23	Jabban	Hydro	22	22
24	Ranolia	Hydro	18	18
Total Small Hydel			**146**	**146**
Sub Total: WAPDA Hydro			**9,547**	**9,547**
GENCOs				
25	Jamshoro - I U1	RFO	250	200
26	Jamshoro - II U4	RFO	200	170
27	Jamshoro - II U2	RFO	-	-
28	Jamshoro - II U3	RFO	-	-
Sub Total: GENCOs – I			**450**	**370**
29	Guddu - I U (11-13)	Gas	415	391
30	Guddu - II U (5-10)	Gas	620	537
31	Guddu 747	Gas	747	721

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable Capacity
			(MW)	
Sub Total: GENCOs – II			1,782	1,649
32	Muzaffargarh - I U1	RFO	210	190
33	Muzaffargarh - I U2	RFO	210	183
34	Muzaffargarh - I U3	RFO	210	184
35	Muzaffargarh - II U4	RFO	320	272
36	Muzaffargarh - II U5	RFO	-	-
37	Muzaffargarh - II U6	RFO	-	-
38	GTPS Block 4 U (5-9)	RLNG	0	0
39	Nandipur	RLNG	525	491
Sub Total: GENCOs – III			1,475	1,320
Total GENCOs (Public Sector)			3,707	3,339
Nuclear				
40	CHASHNUPP - I	Nuclear	325	300
41	CHASHNUPP-II	Nuclear	325	300
42	CHASHNUPP-III	Nuclear	340	315
43	CHASHNUPP-IV	Nuclear	340	315
44	K-2	Nuclear	1,145	1,059
45	K-3	Nuclear	1,145	1,059
Sub Total: Nuclear			3,620	3,348
Private Sector				
Hydel IPPs				
46	Jagran - I	Hydro	30	30
47	Malakand - III	Hydro	81	81
48	New Bong	Hydro	84	84
49	Daral Khwar	Hydro	37	37
50	Gul Pur	Hydro	103	103
51	Patrind	Hydro	150	150
52	Karot	Hydro	720	720
Sub Total: IPPs Hydro			1,205	1,205
Thermal IPPs				
53	AES Pakgen	RFO	365	335
54	AGL	RFO	163	153
55	Altern	Gas	0	0
56	Atlas	RFO	219	209
57	Balloki	RLNG	1,223	1,147
58	Bhikki	RLNG	1,180	1,108
59	China HUBCO	Imp. Coal	1,320	1,249
60	Davis	RLNG	14	10
61	Engro	Gas	217	217
62	Engro Thar	Local Coal	660	545
63	FKPCL	RLNG	172	147

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable Capacity
			(MW)	
64	Foundation	Gas	184	161
65	Halmore	RLNG	225	191
66	Haveli	RLNG	1,230	1,158
67	HCPC	Gas	0	0
68	HuB N	RFO	225	208
69	HUBCO	RFO	1,292	1,108
70	KAPCO 1	RLNG	400	344
71	KAPCO 2	RLNG	900	743
72	KAPCO 3	RLNG	300	258
73	Kohinoor	RFO	131	117
74	Lalpir	RFO	362	338
75	Liberty	Gas	225	208
76	Liberty Tech	RFO	202	192
77	Nishat C	RFO	209	191
78	Nishat P	RFO	202	191
79	Orient	RLNG	225	197
80	Port Qasim	Imp. Coal	1,320	1,243
81	Rousch	RLNG	450	389
82	Saba	RFO	136	112
83	Sahiwal Coal	Imp. Coal	1,320	1,244
84	Saif	RLNG	225	197
85	Sapphire	RLNG	225	196
86	Uch	Gas	586	535
87	Uch-II	Gas	393	370
88	Lucky Coal	Local Coal	660	606
89	Punjab Thermal	RLNG	0	0
Sub Total (IPPs Fossil Fuels)			**17,161**	**15,616**
Bagasse Based Power Projects				
90	Almoiz	Bagasse	36	36
91	Chanar	Bagasse	22	22
92	Chiniot	Bagasse	63	63
93	Fatima Energy (FEL)	Bagasse	120	120
94	Hamza	Bagasse	15	15
95	JDW - II	Bagasse	26	26
96	JDW - III	Bagasse	27	27
97	Ryk_Mills	Bagasse	30	30
98	Thal_Layyah	Bagasse	25	25
Sub Total Bagasse			**364**	**364**
Wind Power Projects				
99	Act/Tapal Wind	Wind	30	30
100	Artistic_Wind	Wind	50	50

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable Capacity
			(MW)	
101	Artistic_Wind-2	Wind	50	50
102	Dawood	Wind	50	50
103	Din Wind Energy	Wind	50	50
104	FFC	Wind	50	50
105	FWEL-I	Wind	50	50
106	FWEL-II	Wind	50	50
107	Gul Ahmed	Wind	50	50
108	Gul Ahmed-II	Wind	50	50
109	Hawa	Wind	50	50
110	Indus	Wind	50	50
111	Jhimpir	Wind	50	50
112	Lakeside Wind	Wind	50	50
113	Liberty Wind-I	Wind	50	50
114	Master	Wind	50	50
115	Master Green	Wind	50	50
116	Metro_Wind	Wind	50	50
117	Metro_Wind-II	Wind	60	60
118	NASDA Green Wind	Wind	50	50
119	Sachal	Wind	50	50
120	Sapphire_Wind	Wind	50	50
121	Tapal Wind-2	Wind	50	50
122	Tenaga	Wind	50	50
123	Three_Gorges_I	Wind	50	50
124	Three_Gorges_II	Wind	50	50
125	Three_Gorges_III	Wind	50	50
126	Tricom	Wind	50	50
127	Tricon_A	Wind	50	50
128	Tricon_B	Wind	50	50
129	Tricon_C	Wind	50	50
130	UEP	Wind	99	99
131	Yunus	Wind	50	50
132	Zephyr	Wind	50	50
133	Zorlu_Wind	Wind	56	56
134	Liberty Wind-II	Wind	50	50
Sub Total (Wind)			**1,845**	**1,845**
Solar Power Projects				
135	Appolo Solar	Solar PV	100	100
136	Best	Solar PV	100	100
137	Crest	Solar PV	100	100
138	QA_Solar	Solar PV	100	100

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable Capacity
			(MW)	
139	Zhenfa	Solar PV	100	100
Sub Total Solar Power Project			**500**	**500**
	Total Public Sector		**16,874**	**16,234**
	Total Private Sector		**21,075**	**19,531**
	Total Installed Capacity (MW)		**37,949**	**35,765**

B-1 (ii). K-Electric Existing Installed Capacity (As of June 2022)

Sr. No.	Name of Power Project	Fuel	Installed Capacity	Dependable Capacity
			MW	
1	BQPS1-U1	RLNG	210	167
2	BQPS1-U2	RLNG	210	169
3	BQPS1-U5	RLNG	210	175
4	BQPS1-U6	RLNG	210	167
5	BQPS2	RLNG	573	480
6	KCCPP	RLNG	248	211
7	BQPS3	RLNG	918	900
8	KTGTPS	RLNG	107	89
9	SGTPS	RLNG	107	89
10	SNPC-I	Gas	52	50
11	SNPC-II	Gas	52	50
12	FPCL	Imp. Coal	60	52
13	Tapal	RFO	126	120
14	GAEL	RFO	136	123
15	Oursun	Solar PV	50	50
16	Gharo	Solar PV	50	50
Total Installed Capacity (MW)			**3,319**	**2,941**

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

#	Project Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost	
			($/kW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)	Rs/kWh
			Existing Power Projects					
1	K-3	Uranium	52.20	0.00	0.47	10.00	4.70	0.84
2	K-2	Uranium	52.28	0.00	0.47	10.00	4.77	0.85
3	C-3	Uranium	99.91	0.00	0.49	10.91	5.35	0.95
4	C-1	Uranium	135.48	0.00	0.50	10.91	5.47	0.97

#	Project Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost	
			($/kW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)	Rs/kWh
5	C-2	Uranium	124.60	0.00	0.58	10.91	6.33	1.13
6	C-4	Uranium	99.08	0.00	0.61	10.91	6.65	1.18
7	Lucky	Local Coal	25.39	2.94	0.95	9.23	11.71	2.08
8	Uch (Below 152GWh)	Gas	13.10	2.50	1.22	7.65	11.80	2.10
9	Liberty (Below 61GWh)	Gas	60.23	3.09	1.74	7.07	15.38	2.74
10	Engro Thar	Local Coal	26.6+312.36	6.21	1.47	9.66	20.37	3.62
11	Guddu 747 CC	Gas	18.44	3.72	4.56	7.32	37.12	6.61
12	Guddu-I U (11-13)	Gas	25.12	0.39	4.56	9.00	41.48	7.38
13	Foundation	Gas	23.01	4.03	5.06	7.68	42.84	7.62
14	Uch-II	Gas	26.00	2.33	5.33	8.19	46.02	8.19
15	Guddu-II U (5-10)	Gas	25.12	0.39	4.56	10.00	46.04	8.19
16	Uch (Above 152GWh)	Gas	13.10	2.50	5.86	7.65	47.34	8.42
17	Engro 90MW	Gas	16.67	3.56	5.06	9.73	52.82	9.40
18	Liberty (Above 61GWh)	Gas	60.23	3.09	8.70	7.07	64.56	11.49
19	Port Qasim	Imported Coal	28.07	1.24	14.15	9.01	128.71	22.90
20	Haveli	RLNG	12.34	1.33	20.87	6.53	137.58	24.48
21	Balloki	RLNG	12.64	1.48	20.87	6.58	138.80	24.70
22	Bhikki	RLNG	18.44	3.72	20.87	6.59	141.28	25.14
23	Sahiwal Coal	Imported Coal	24.87	1.22	17.50	8.51	150.09	26.71
24	China HUBCO	Imported Coal	26.64	3.02	17.39	8.95	158.73	28.25
25	Orient	RLNG	26.59	2.49	23.11	7.25	170.10	30.27
26	Halmore	RLNG	19.84	4.25	23.11	7.25	171.69	30.55
27	Saphire	RLNG	19.57	4.19	23.11	7.25	171.80	30.57
28	Saif	RLNG	20.32	4.23	23.11	7.25	171.86	30.58
29	Nandipur	RLNG	18.51	4.20	23.11	7.35	173.99	30.96
30	KAPCO 1	RLNG	19.22	2.48	20.87	8.38	177.38	31.56
31	AGL	RFO	26.96	9.84	20.38	8.66	186.38	33.17
32	Rousch	RLNG	19.22	2.62	20.87	8.84	187.06	33.29
33	Liberty Tech	RFO	23.86	10.60	21.30	8.50	191.62	34.10

#	Project Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost	
			($/kW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)	Rs/kWh
34	KAPCO 2	RLNG	19.22	2.89	20.87	9.19	194.74	34.65
35	Kohinoor	RFO	19.22	5.57	21.52	8.97	198.59	35.34
36	HuB N	RFO	23.78	8.47	24.58	7.95	203.86	36.28
37	KAPCO 3	RLNG	19.22	5.58	20.87	9.51	203.99	36.30
38	Engro 127MW	HSD	16.67	3.56	28.97	7.06	208.03	37.02
39	FKPCL	RLNG	19.22	7.04	12.63	15.99	208.89	37.17
40	Jamshoro-I U1	RFO	17.55	0.52	17.70	11.79	209.20	37.23
41	ATLAS	RFO	22.66	9.72	23.65	8.49	210.55	37.47
42	Saba	RFO	19.22	1.60	21.56	9.81	213.11	37.92
43	Lalpir	RFO	19.22	1.60	21.67	10.10	220.38	39.22
44	HUBCO	RFO	15.43	1.62	21.12	10.37	220.71	39.28
45	Jamshoro-II U4	RFO	17.55	0.52	17.70	12.62	223.76	39.82
46	Nishat P	RFO	23.49	9.72	22.34	9.71	226.59	40.32
47	Nishat C	RFO	23.45	9.70	21.39	10.17	227.14	40.42
48	AES Pakgen	RFO	19.22	1.60	21.63	10.43	227.16	40.42
49	Altern	Gas	86.77	6.48	22.56	9.79	227.34	40.45
50	Davis	RLNG	21.02	5.38	22.56	9.90	228.72	40.70
51	Muzaffargarh-II U4	RFO	27.54	0.91	21.02	11.72	247.19	43.99
52	Muzaffargarh-I U3	RFO	27.54	0.91	21.02	11.74	247.56	44.05
53	Muzaffargarh-I U1	RFO	27.54	0.91	21.02	11.99	252.98	45.02
54	Muzaffargarh-I U2	RFO	27.54	0.91	21.02	12.16	256.40	45.63
Committed Power Projects								
55	Thar-I (SSRL)	Local Coal	25.4+71.81	6.20	1.47	9.23	19.72	3.51
56	Thal Nova	Local Coal	27.16+71.81	6.20	1.47	9.73	20.45	3.64
57	Thar TEL	Local Coal	27.16+71.81	6.20	1.47	9.73	20.45	3.64
58	Gwadar	Local Coal	33.77	1.15	2.80	9.66	28.21	5.02
59	Jamshoro Coal U1	Imported Coal	5.06	2.85	6.17	8.71	56.59	10.07
60	Trimmu	RLNG	13.29	3.14	20.87	5.89	125.96	22.42
Candidate Power Projects								
61	New_Nuclear	Uranium	73.89	0.00	0.47	9.57	4.50	0.80

#	Project Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost	
			($/kW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)	Rs/kWh
62	C-5	Uranium	73.89	0.00	0.47	9.57	4.50	0.80
63	NEW_L.Coal II	Local Coal	25.17+71.81	5.93	0.88	9.23	14.07	2.50
64	NEW_L.Coal 660	Local Coal	26.6+71.81	6.21	0.88	9.23	14.35	2.55
65	NEW_L.Coal 330	Local Coal	26.6 +71.81	6.21	0.88	9.73	14.79	2.63
66	Jamshoro Coal U2	Imported Coal	5.06	2.85	6.17	9.11	59.05	10.51
67	New_CCGT	RLNG	13.29	3.14	20.87	5.89	125.96	22.42
68	NEW_Imp.Coal	Imported Coal	26.64	3.02	17.39	9.23	163.57	29.11
69	NEW OCGT	RLNG	13.29	3.14	20.87	9.46	200.62	35.70

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

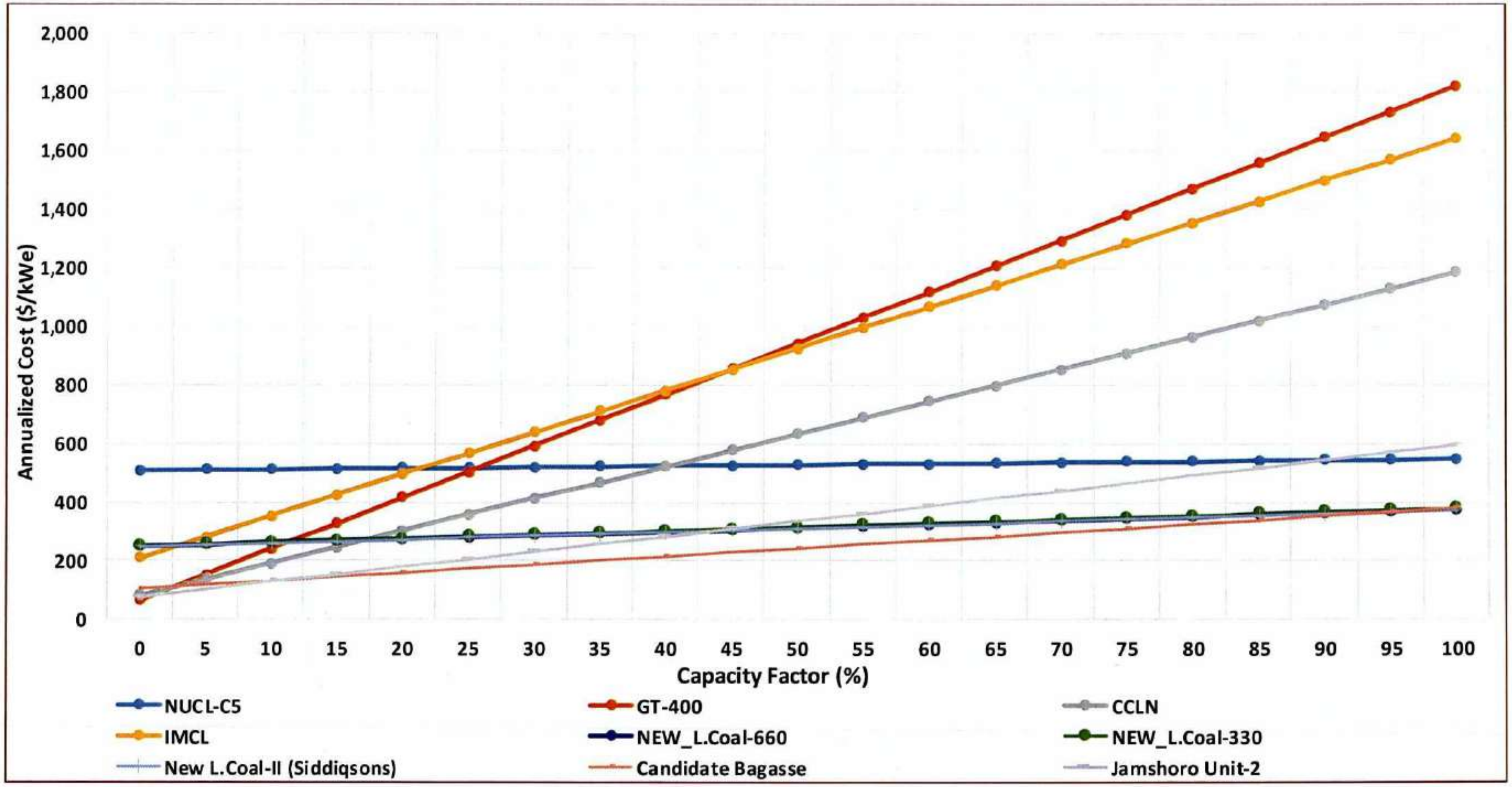
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Mar. 22 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
1	Taobut	10	11.2	3	14.2	10.29	3.24	13.53	1,353
2	Thakot-III	1490	1279.6	962.9	2242.5	1019.80	1074.88	2094.69	1,406
3	Dowarian	40	42	18	60	38.58	19.45	58.03	1,451
4	Nagdar	35	36.75	15.75	52.5	33.76	17.02	50.78	1,451
5	Batdara	5	5.25	2.25	7.5	4.82	2.43	7.25	1,451
6	Janawai	12	13.44	5	18.44	12.34	5.40	17.75	1,479
7	Shounter	48	53.76	23.04	76.8	49.38	24.90	74.28	1,547
8	Asrit Kedam	215	260.132	111.44	371.572	207.07	146.70	353.77	1,645
9	Kalam Asrit	238	269.93	129.8	399.73	271.52	131.88	403.40	1,695
10	Jagran-IV	22	27.41	11.75	39.16	25.18	12.70	37.87	1,722
11	CJ	25	28.5	19	47.5	21.37	21.68	43.05	1,722
12	Mahl	640	767.5	502.5	1270	570.91	554.16	1125.07	1,758
13	Taunsa	135	143	104	247	128.58	111.08	239.66	1,775
14	Bata Kundi	99	108.42	79.787	188.207	84.22	93.24	177.45	1,792
15	Ashkot	300	204.67	329.8	534.47	204.73	335.08	539.81	1,799
16	Turtonas Uzghor	82.25	10.692	122.958	133.65	18.38	131.21	149.58	1,819
17	Patan	2400	2235	2335	4570	1765.07	2765.01	4530.08	1,888
18	Chowkel Khwar	60	70	50	120	61.76	51.63	113.38	1,890

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Mar. 22 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
19	Balkani	7.75	12	3	15	12.14	3.05	15.19	1,960
20	Arkari Gol	99	137.25	77.3	214.55	105.56	89.43	195.00	1,970
21	Rajdhani	132	0	173	173	0.00	264.64	264.64	2,005
22	Nila Da Katha	31.3	0	58.4	58.4	0.00	64.22	64.22	2,052
23	Artistic-II	55.032	81.5185	31.9815	113.5	81.54	32.49	114.04	2,072
24	Naran	188	269.4	161.9	431.3	234.17	192.44	426.62	2,269
25	Lower Spat Gah	496	247	829	1076	233.65	898.12	1131.77	2,282
26	Chakoti Hatian	500	0	983.12	983.13	0.00	1163.88	1163.88	2,328
27	Kari Mashkur	495	761.04	403.53	1164.57	719.91	437.17	1157.09	2,338
28	Shigo Kas	102	257.88	48.89	306.77	185.35	55.09	240.44	2,357
29	Sharmai	152.12	232.279	137.298	369.577	215.38	146.65	362.02	2,380
30	Daral Khwar-II	9.5	13.6	10.06	23.66	12.06	10.90	22.96	2,417
31	Gabral Utror	79	147.0	52.6	199.7	135.03	56.88	191.91	2,429
32	Chiniot_HPP	80	188.5	25.75	214.25	167.32	27.90	195.22	2,440
33	Harigehl-Majeedgala	40.32	70.301	37.858	108.159	54.96	44.23	99.19	2,460
34	Kalkot Barikot	47	91.94	28.3	120.24	87.83	28.75	116.59	2,481
35	Mujigram	64.26	142.477	35.619	178.096	120.68	42.50	163.18	2,539
36	Bankhwar	35	67.17	25.91	93.08	61.70	28.00	89.70	2,563
37	Tangar	25.91	35.28	34.209	69.489	27.13	39.58	66.71	2,575
38	Mahandri	10.04	19.69	10.29	0	15.14	11.91	27.05	2,694

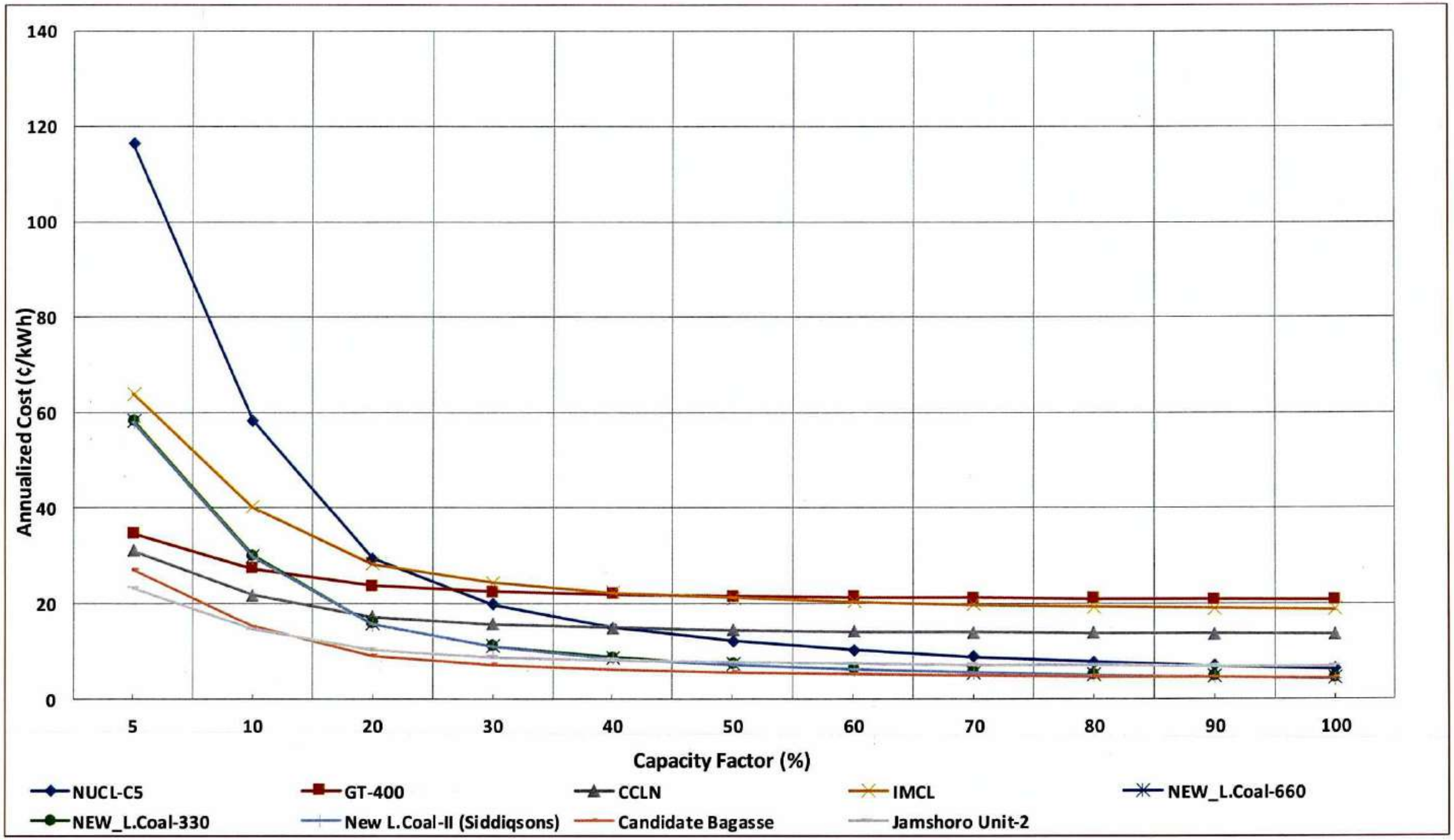
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Mar. 22 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
39	Gumat Nar	49.5	130.82	30.2	161.02	102.28	35.28	137.56	2,779
40	Trappi	32	77.4	19.3	96.7	68.61	20.94	89.56	2,799
41	Kaigah-III	21.1	27.72	33.62	61.34	22.59	37.14	59.73	2,831
42	Jhing-II	6.05	10	8.07	18.07	7.86	9.41	17.27	2,855
43	Patrak Sheringhal	22	46.75	20.48	67.23	44.66	20.81	65.47	2,976
44	Kaigah-II	39.6	39.21	80.71	119.92	29.61	90.94	120.55	3,044
45	Shalfalam	60	0	170.18	170.18	0.00	184.37	184.37	3,073
46	Ghorband	20.6	48.4	21.0	69.4	40.97	25.01	65.98	3,203
47	Athmuqam	450	0	1315	1315	0.00	1449.56	1449.56	3,221
48	Luat	49	47.33	107.525	154.855	36.16	124.40	160.56	3,277
49	Kaigah	545	0	1564.8	1564.8	0.00	1866.11	1866.11	3,424
50	Artistic-I	62.606	187.47	49.37	236.84	172.19	53.35	225.54	3,603
51	Istaro-Booni	72	150	110	260	129.43	130.73	260.16	3,613
52	Nandihar	12.3	31.54	15.547	47.087	26.71	18.54	45.25	3,679
53	Jagran-III	35	64.64	60.98	125.62	55.49	74.82	130.31	3,723
54	Gahret	377	1351.03	486.59	1837.62	1041.03	568.50	1609.53	4,269
55	Ghail	1.1	2.6	2.06	4.66	2.23	2.53	4.75	4,322

B-4. Screening Curve for Candidate Thermal Projects

B - 4.1. Screening Curve For Candidate Thermal Projects ($/kW/Yr)



B - 4.2 Screening Curve for candidate Projects (¢/kWh)



B-5. Annualized Cost of Candidate Hydro Power Projects

#	Power Project	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Project Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/kW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
1	Thakot-III	WAPDA	1490	2030	20.01	1,406	7407	50	57%	3.25	161.80
2	Janawai	AJK-HEB	12	2029	10.10	1,479	60	30	57%	3.34	166.99
3	Bata Kundi	GoKPK	99	2028	5.73	1,792	511	49	59%	3.62	186.67
4	Taobut	AJK-HEB	10	2029	10.10	1,353	41	30	47%	3.72	153.62
5	Batdara	AJK-HEB	5	2025	10.10	1,451	22	30	50%	3.78	163.99
6	Nagdar	AJK	35	2029	10.10	1,451	152	30	50%	3.78	163.99
7	Dowarian	AJK	40	2029	10.10	1,451	174	30	50%	3.78	163.99
8	Asrit Kedam	PEDO	215	2029	9.88	1,645	945	80	50%	3.97	174.50
9	Taunsa	PPDB	135	2028	13.92	1,775	651	50	55%	4.00	192.96
10	Shounter	AJK	48	2029	10.10	1,547	208	30	50%	4.01	174.25
11	CJ	PPDB	25	2028	14.05	1,722	111	50	51%	4.24	187.73
12	Jagran-IV	AJK	22	2029	10.10	1,722	96	30	50%	4.42	192.72
13	Harigehl-Majeedgala	AJK	40.32	2028	1.05	2,460	227	50	64%	4.43	249.17
14	Patan	WAPA	2400	2031	43.29	1,888	12520	50	60%	4.48	233.66
15	Kalam Asrit	PEDO	238	2029	9.84	1,695	944	50	45%	4.56	180.79
16	Mahl	PPIB	640	2030	16.89	1,758	2694	50	48%	4.61	194.19
17	Ashkot	PPIB	300	2030	15.64	1,799	1263	50	48%	4.68	197.13
18	Rajdhani	PPIB	132	2029	39.17	2,005	677	50	59%	4.71	241.38
19	Balkani	PEDO	7.75	2026	26.02	1,960	35	50	52%	4.95	223.65

#	Power Project	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Project Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/kW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
20	Nila Da Katha	PEDO	31.3	2028	11.39	2,052	142	30	52%	5.06	229.02
21	Chakoti Hatian	PPIB	500	2031	13.64	2,328	2430	50	55%	5.11	248.42
22	Turtonas Uzghor	PPIB	82.25	2029	54.52	1,819	381	50	53%	5.14	237.95
23	Jhing-II	AJK-PPC	6.05	2028	0.48	2,855	34	50	64%	5.16	288.44
24	Chowkel Khwar	PEDO	60	2028	10.83	1,890	241	30	46%	5.26	211.29
25	Ghorband	GoKPK	20.6	2028	24.19	3,203	134	50	74%	5.35	347.25
26	Shigo Kas	PEDO	102	2029	41.21	2,357	525	80	59%	5.38	277.05
27	Kari Mashkur	GoKPK	495	2029	15.95	2,338	2204	50	51%	5.65	251.72
28	Daral Khwar-II	PEDO	9.5	2024	18.03	2,417	44	50	53%	5.68	261.79
29	Mujigram	GoKPK	64.26	2031	12.99	2,539	304	50	54%	5.69	269.10
30	Artistic-II	PEDO	55.032	2028	13.01	2,072	212	60	44%	5.74	220.91
31	Trappi	PEDO	32	2028	1.30	2,799	165	30	59%	5.78	298.17
32	Arkari Gol	PEDO	99	2029	23.81	1,970	379	50	44%	5.81	222.46
33	Nandihar	GoKPK	12.3	2026	27.93	3,679	83	50	77%	5.93	398.96
34	Sharmai	PEDO	152.12	2029	31.65	2,380	690	100	52%	5.95	269.65
35	Naran	GoKPK	188	2029	5.71	2,269	704	50	43%	6.26	234.58
36	Kaigah-III	PEDO	21.1	2029	0.16	2,831	101	30	55%	6.26	300.47
37	Gumat Nar	AJK	49.5	2029	1.56	2,779	220	50	51%	6.34	281.85
38	Lower Spat Gah	PEDO	496	2030	2.08	2,282	1898	30	44%	6.38	244.13
39	Kalkot Barikot	GoKPK	47	2029	8.68	2,481	186	50	45%	6.55	258.86
40	Kaigah-II	PEDO	39.6	2029	0.47	3,044	190	30	55%	6.73	323.41

#	Power Project	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Project Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/kW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
41	Gabral Utror	PEDO	79	2028	20.58	2,429	311	40	45%	6.84	269.00
42	Tangar	PEDO	25.91	2028	33.56	2,575	116	30	51%	6.84	306.70
43	Mahandri	PEDO	10.04	2028	33.66	2,694	44	50	50%	6.97	305.39
44	Chiniot_HPP	WAPDA	80	2028	4.51	2,440	275	50	39%	7.30	250.63
45	Shalfalam	PEDO	60	2029	7.96	3,073	269	30	51%	7.44	333.92
46	Luat	AJK	49	2029	1.48	3,277	213	50	50%	7.65	331.98
47	Artistic-I	PEDO	62.606	2028	27.97	3,603	307	60	56%	7.95	389.41
48	Patrak Sheringhal	GoKPK	22	2029	8.78	2,976	85	50	44%	7.95	308.93
49	Athmuqam	PPIB	450	2029	28.10	3,221	1982	50	50%	8.02	353.00
50	Bankhwar	PEDO	35	2028	22.51	2,563	124	40	40%	8.05	284.57
51	Jagran-III	AJK	35	2029	1.28	3,723	162	30	53%	8.54	396.22
52	Ghail	AJK-PPC	1.1	2027	0.05	4,322	5	50	53%	9.46	435.97
53	Gahret	GoKPK	377	2031	15.71	4,269	1768	50	54%	9.52	446.31
54	Istaro-Booni	GoKPK	72	2031	12.17	3,613	279	50	44%	9.73	376.61
55	Kaigah	PPIB	545	2031	37.14	3,424	374	50	8%	55.74	382.49

B-6. Candidate Hydro projects COD optimized by PLEXOS for different scenarios

#	Candidate Plants Name	Category	Capacity	COD given to PLEXOS	Base Case	Scenarios					
						Low Demand	High Demand	Bhasha in 2029	C-5 in 2029	Local Coal in 2027 & 2030	Unconstrained VRE
					Year	Year	Year	Year	Year	Year	Year
1	Daral Khwar-II	Hydro	9.5	Jun-24	2025	2025	2025	2025	2025	2025	2025
2	Batdara	Hydro	5	May-25	2026	2026	2026	2026	2026	2026	2026
3	Balkani	Hydro	7.75	Jul-25	2026	2026	2026	2026	2026	2026	2026
4	Nandihar	Hydro	12.3	Jun-26	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
5	Ghail	Hydro	1.1	Dec-26	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
6	Jhing-II	Hydro	6.05	Jul-27	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
7	Artistic-I	Hydro	62.606	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
8	Artistic-II	Hydro	55.032	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
9	Bankhwar	Hydro	35	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
10	Bata Kundi	Hydro	99	Jun-28	2029	2029	2029	2030	2029	2029	2029
11	Chiniot_HPP	Hydro	80	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
12	Chowkel Khwar	Hydro	60	Jun-28	2029	Not Picked	2029	Not Picked	Not Picked	Not Picked	2029
13	CJ	Hydro	25	Jun-28	2029	2029	2029	2029	2029	2029	2029
14	Gabral Utror	Hydro	79	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
15	Ghorband	Hydro	20.6	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked

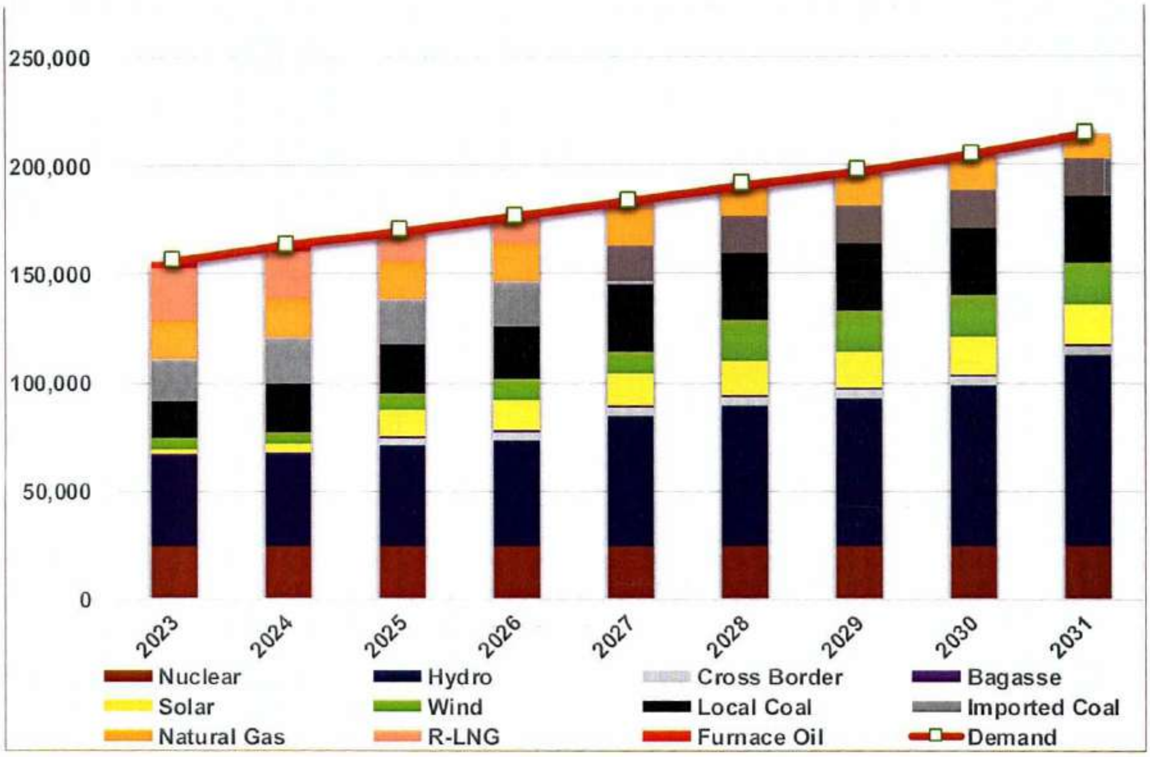
#	Candidate Plants Name	Category	Capacity	COD given to PLEXOS	Base Case	Scenarios					
						Low Demand	High Demand	Bhasha in 2029	C-5 in 2029	Local Coal in 2027 & 2030	Unconstrained VRE
					Year	Year	Year	Year	Year	Year	Year
16	Harigehl-Majeedgala	Hydro	40.32	Jun-28	Not Picked	Not Picked	2029	Not Picked	Not Picked	Not Picked	Not Picked
17	Mahandri	Hydro	10.04	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
18	Nila Da Katha	Hydro	31.3	Jun-28	2029	2029	2029	Not Picked	2029	2029	2029
19	Tangar	Hydro	25.91	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
20	Taunsa	Hydro	135	Jun-28	2029	2029	2029	2030	2029	2029	2029
21	Trappi	Hydro	32	Jun-28	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
22	Taobut	Hydro	10	Jul-28	2029	2029	2029	2029	2029	2029	2029
23	Janawai	Hydro	12	Jan-29	2030	2030	2030	2030	2030	2030	2030
24	Rajdhani	Hydro	132	Feb-29	2030	2030	2030	2030	2030	2030	2030
25	Kalam Asrit	Hydro	238	Mar-29	2030	Not Picked	2030	Not Picked	Not Picked	Not Picked	2030
26	Athmuqam	Hydro	450	May-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
27	Arkari Gol	Hydro	99	Jun-29	2030	2030	2030	2030	2030	2030	2030
28	Asrit Kedam	Hydro	215	Jun-29	2030	2030	2030	2030	2030	2030	2030
29	Dowarian	Hydro	40	Jun-29	2030	2030	2030	2030	2030	2030	2030
30	Gumat Nar	Hydro	49.5	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
31	Jagran-III	Hydro	35	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked

#	Candidate Plants Name	Category	Capacity	COD given to PLEXOS	Base Case	Scenarios					
						Low Demand	High Demand	Bhasha in 2029	C-5 in 2029	Local Coal in 2027 & 2030	Unconstrained VRE
					Year	Year	Year	Year	Year	Year	Year
32	Jagran-IV	Hydro	22	Jun-29	2030	2030	2030	2030	2030	2030	2030
33	Kaigah-II	Hydro	39.6	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
34	Kaigah-III	Hydro	21.1	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
35	Kalkot Barikot	Hydro	47	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
36	Kari Mashkur	Hydro	495	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
37	Luat	Hydro	49	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
38	Nagdar	Hydro	35	Jun-29	2030	2030	2030	2030	2030	2030	2030
39	Naran	Hydro	188	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
40	Patrak Sheringhal	Hydro	22	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
41	Shalfalam	Hydro	60	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
42	Sharmai	Hydro	152.12	Jun-29	2030	2030	2030	2030	2030	2030	2030
43	Shigo Kas	Hydro	102	Jun-29	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
44	Shounter	Hydro	48	Jun-29	2030	2030	2030	2030	2030	2030	2030
45	Turtonas Uzghor	Hydro	82.25	Jun-29	2030	2030	2030	2030	2030	2030	2030
46	Thakot-III	Hydro	1490	Oct-29	2031	2031	2031	2031	2031	2031	2031
47	Mahl	Hydro	640	Jan-30	2031	2031	2031	2031	2031	2031	2031

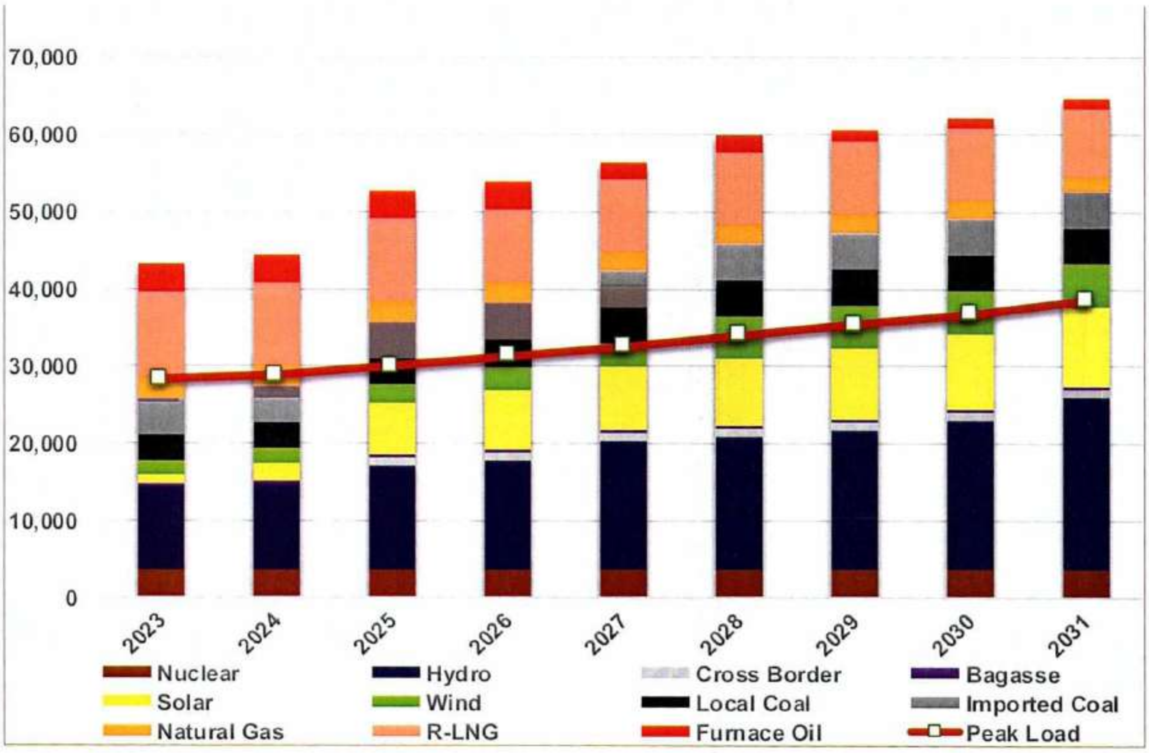
#	Candidate Plants Name	Category	Capacity	COD given to PLEXOS	Base Case	Scenarios					
						Low Demand	High Demand	Bhasha in 2029	C-5 in 2029	Local Coal in 2027 & 2030	Unconstrained VRE
					Year	Year	Year	Year	Year	Year	Year
48	Ashkot	Hydro	300	Mar-30	Not Picked	Not Picked	2031	Not Picked	Not Picked	Not Picked	Not Picked
49	Lower Spat Gah	Hydro	496	May-30	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
50	Gahret	Hydro	377	Dec-30	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
51	Istaro-Booni	Hydro	72	Dec-30	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
52	Mujigram	Hydro	64.26	Dec-30	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
53	Patan	Hydro	2400	Jan-31	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
54	Chakoti Hatian	Hydro	500	Jan-31	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked
55	Kaigah	Hydro	545	Feb-31	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked	Not Picked

Annexure C. Low Demand Scenario

C-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



C-2. Installed Capacity Vs Peak Demand (MW) - Country



C-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	13	-	480	-	150	500	50	-	1,193	6,272
2027	-	990	-	-	-	-	150	-	50	-	1,190	7,462
2028	-	-	-	-	-	-	150	2,403	50	-	2,603	10,065
2029	-	-	300	-	-	-	150	-	50	-	500	10,566
2030	-	-	755	82	-	-	150	-	50	-	1,037	11,603
2031	-	-	2,130	-	-	-	150	-	50	-	2,330	13,933
Total	**-**	**990**	**3,208**	**82**	**3,600**	**1,250**	**1,050**	**3,403**	**350**	**-**	**13,933**	

C-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
Generation Additions in 2021-22 (MW)			20	20			
Cumulative Addition up till 2021-22 (MW)			20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
Generation Additions in 2022-23 (MW)			4,640	4,421			
Cumulative Addition up till 2023 (MW)			4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2023-24							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
2024-25							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			8,337	8,337			
Cumulative Addition up till 2025 (MW)			14,590	14,371			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_Utility	Solar	480	480	Yet to be determined	Optimized	Jul-25
7	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
8	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25
9	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25

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#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
11	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
12	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
	Generation Additions in 2025-26 (MW)		2,503	2,476			
	Cumulative Addition up till 2026 (MW)		17,093	16,847			
			2026-27				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
7	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
8	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
9	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
10	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
11	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
12	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
13	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
14	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
15	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
	Generation Additions in 2026-27 (MW)		4118	4040			
	Cumulative Addition up till 2027 (MW)		21,211	20,887			
			2027-28				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27

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#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	2,403	2,403	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			3,518	3,518			
Cumulative Addition up till 2028 (MW)			24,729	24,405			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
6	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
7	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
8	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
9	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
10	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
11	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			1,396	1,396			
Cumulative Addition up till 2029 (MW)			26,125	25,801			
2029-30							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
8	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
9	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
10	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
15	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
16	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			1,858	1,858			
Cumulative Addition up till 2030 (MW)			27,982	27,658			
2030-31							
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
	Generation Additions in 2030-31 (MW)		3,549	3,549			
	Cumulative Addition up till 2031 (MW)		31,531	31,207			

C-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.48	6.35	6.33	6.43	6.05
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.27	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.17	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.19	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.75	55.78
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.76	54.79	54.79
80	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
81	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
82	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
83	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
84	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
85	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
86	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
87	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94
88	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
89	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
90	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.34
91	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.90	51.90
92	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	54.06	52.77
93	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
94	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
95	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
96	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.83	42.83	42.83
97	Jagran-II	HPP Committed	50.53	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
98	Karot	HPP Committed	44.39	44.29	44.39	44.39	44.39	44.29	44.38	44.39	44.39
99	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
100	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
101	Koto	HPP Committed	57.12	57.08	57.24	57.24	57.24	57.03	57.12	57.19	57.24
102	Lawi	HPP Committed	0.00	48.05	48.10	48.10	48.10	47.96	48.00	48.05	48.08
103	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
104	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	46.36	42.60	42.71	42.71	42.71
105	Suki Kinari	HPP Committed	0.00	49.07	45.52	49.07	49.07	48.93	49.07	49.07	49.07
106	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
107	Chamfall	HPP Committed	0.00	48.99	49.12	49.12	49.12	48.99	49.12	49.12	49.12
108	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.62	73.66	73.60	73.62	73.66	73.66
109	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
110	Deg Outfall	HPP Committed	76.29	76.09	76.29	76.29	76.29	76.09	76.29	76.29	76.29
111	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
112	Karora	HPP Committed	67.62	67.57	67.62	67.62	67.62	67.50	67.48	67.55	67.58
113	Kathai-II	HPP Committed	0.00	0.00	60.37	60.37	60.37	60.21	60.37	60.37	60.37
114	Kurram Tangi	HPP Committed	0.00	17.05	17.05	17.05	17.05	17.01	17.05	17.05	17.05
115	Riali-II	HPP Committed	0.00	53.15	53.17	53.17	53.17	53.01	53.15	53.16	53.17
116	Allai Khwar	HPP Existing	44.32	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
117	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
118	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
119	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
120	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
121	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
122	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
123	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
124	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
125	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
126	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
127	Mangla	HPP Existing	64.98	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
128	Neelum Jehlum	HPP Existing	51.69	51.54	51.69	51.69	51.69	51.54	51.69	51.69	51.69
129	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
130	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
131	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
132	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
133	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
134	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
135	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.73	70.05	35.95	33.04	30.71	23.52
136	Foundation	CCGT_Gas	89.99	90.25	90.00	89.99	83.30	68.94	82.19	81.04	57.94
137	Guddu-I	CCGT_Gas	36.91	74.63	74.43	74.43	69.66	67.68	71.24	70.91	29.95
138	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
139	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	75.56	73.95	74.52	74.66	70.94
140	Liberty	CCGT_Gas	74.41	75.02	43.44	42.43	0.00	0.00	0.00	0.00	0.00
141	Uch	CCGT_Gas	86.08	86.32	86.08	86.08	81.53	43.77	45.45	48.06	0.00
142	Uch-II	CCGT_Gas	87.79	88.05	87.81	87.79	80.87	51.33	70.29	74.24	51.31
143	SNPC-I	KE_CCGT_Gas	91.98	92.25	92.00	91.96	85.01	31.42	83.31	80.20	33.09
144	SNPC-II	KE_CCGT_Gas	91.98	92.25	92.00	91.96	85.04	33.23	83.46	80.32	35.97
145	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
146	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
147	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
156	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
158	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
159	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
160	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
164	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
165	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
166	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
167	K-2	Nuclear	85.07	85.30	85.07	85.07	85.07	85.29	85.05	85.06	85.06

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
168	K-3	Nuclear	85.67	85.90	85.67	85.67	85.67	85.90	85.65	85.66	85.66
169	Engro Thar	Local Coal	82.51	82.74	82.51	82.51	82.51	82.14	82.06	82.35	80.46
170	Gwadar	Local Coal	0.00	0.00	0.00	69.18	83.34	82.42	82.47	82.75	78.64
171	Lucky	Local Coal	85.08	85.31	85.08	85.08	85.08	85.31	85.07	85.08	85.08
172	Thal Nova	Local Coal	49.35	85.21	84.98	84.98	84.98	85.21	84.97	84.98	84.97
173	Thar TEL	Local Coal	84.98	85.21	84.98	84.98	84.98	84.92	84.90	84.98	84.97
174	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	85.21	84.98	84.98	84.98
175	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.33	83.55	83.33	83.33	83.33
176	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
177	Jamshoro Coal	Imported Coal	49.09	83.17	81.82	81.21	31.73	14.12	18.50	19.16	13.87
178	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
179	Sahiwal Coal	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
180	FPCL	KE_Imported Coal	82.15	77.03	16.03	16.76	10.04	6.26	9.45	10.34	8.83
181	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182	Balloki	CCGT_RLNG	3.89	1.62	0.51	1.05	0.67	0.28	0.29	0.37	0.29
183	Bhikki	CCGT_RLNG	1.10	0.73	0.00	0.06	0.24	0.00	0.15	0.24	0.13
184	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
185	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
186	Haveli	CCGT_RLNG	10.24	4.81	1.99	3.46	2.29	0.62	1.26	1.19	0.70
187	KAPCO 1	CCGT_RLNG	35.22	35.38	35.26	0.00	0.00	0.00	0.00	0.00	0.00
188	KAPCO 2	CCGT_RLNG	11.90	11.83	11.88	0.00	0.00	0.00	0.00	0.00	0.00
189	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
190	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.00	0.00
191	Orient	CCGT_RLNG	37.73	22.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Rousch	CCGT_RLNG	0.17	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
194	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
195	Trimmu	CCGT_RLNG	25.17	13.25	8.97	9.14	6.55	2.16	2.81	2.73	2.80
196	BQPS2	KE_CCGT_RLNG	85.12	82.89	26.77	22.73	13.87	5.35	7.78	9.39	7.96
197	BQPS3	KE_CCGT_RLNG	89.69	89.68	62.12	83.43	24.84	13.48	16.27	17.16	14.15
198	KCCPP	KE_CCGT_RLNG	77.73	82.18	18.36	16.71	9.99	3.67	5.98	6.13	6.74
199	KTGTPS	KE_CCGT_RLNG	43.99	38.51	5.71	6.07	3.76	1.91	2.15	2.00	1.55
200	SGTPS	KE_CCGT_RLNG	47.49	42.85	6.60	6.93	4.09	2.31	2.59	2.47	1.82
201	BQPS1-U1	KE_ST_RLNG	9.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	BQPS1-U5	KE_ST_RLNG	28.46	28.19	1.52	1.52	0.00	0.00	0.00	0.00	0.02
203	BQPS1-U6	KE_ST_RLNG	15.15	14.14	1.09	1.13	0.00	0.00	0.00	0.00	0.00
204	BQPS1-U2	KE_GT_RLNG	21.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

C-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
Jun-22	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	1,550	-	-	-	1,203	53,912
2027	990	2,558	-	-	-	570	-225	-1,292	-	2,601	56,513
2028	-	545	-	-	-	2,973	-	-131	-	3,387	59,900
2029	-	826	-	-	-	570	-	-727	-	669	60,568
2030	-	1,288	-172	-	-	570	-	-136	-	1,550	62,118
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	64,631
Total	**4,590**	**22,403**	**8,710**	**3,620**	**4,680**	**16,348**	**1,933**	**1,347**	**1,000**	**23,370**	**64,631**

C-7. IGCEP Generation Mix 2023-2031 (GWh)

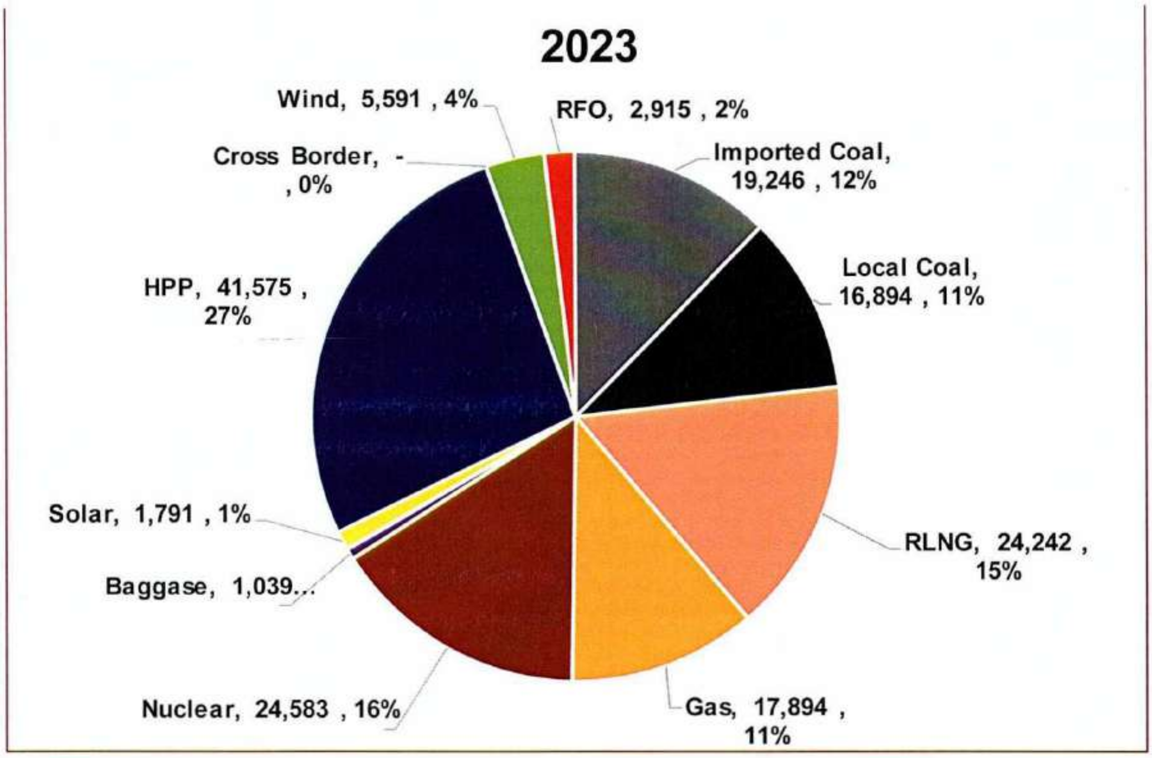


Chart C-1: IGCEP Generation Mix 2023 (GWh)

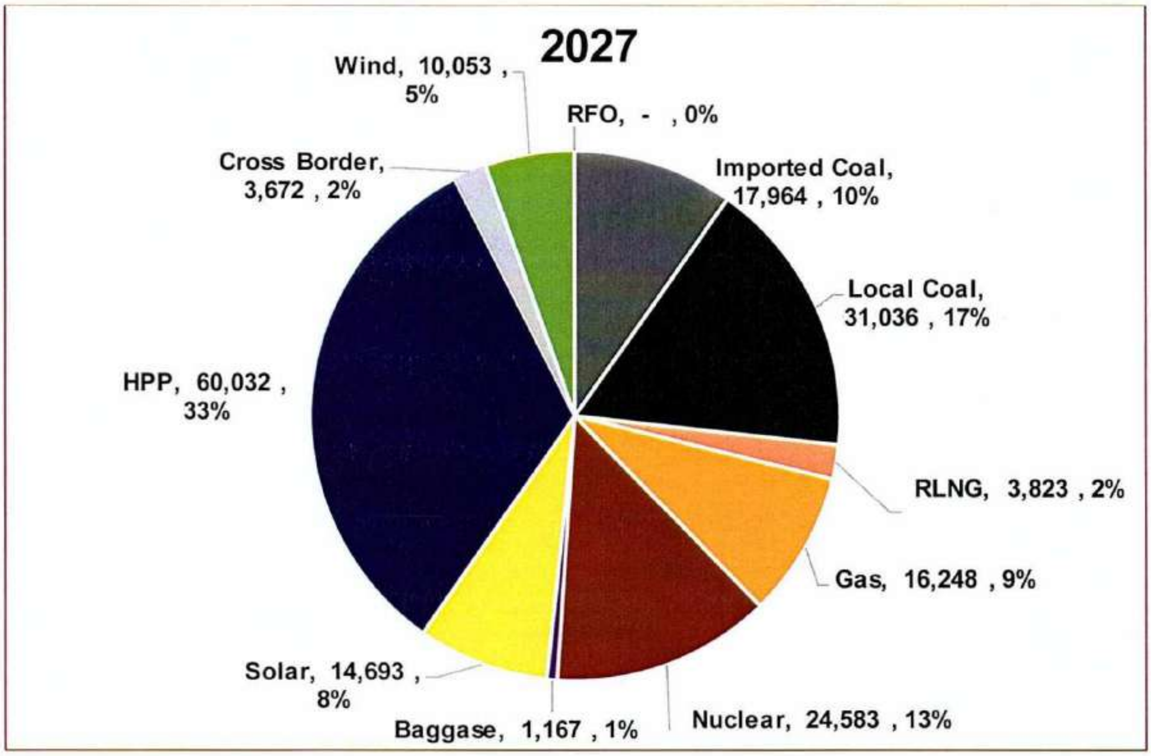


Chart C-2: IGCEP Generation Mix 2027 (GWh)

η

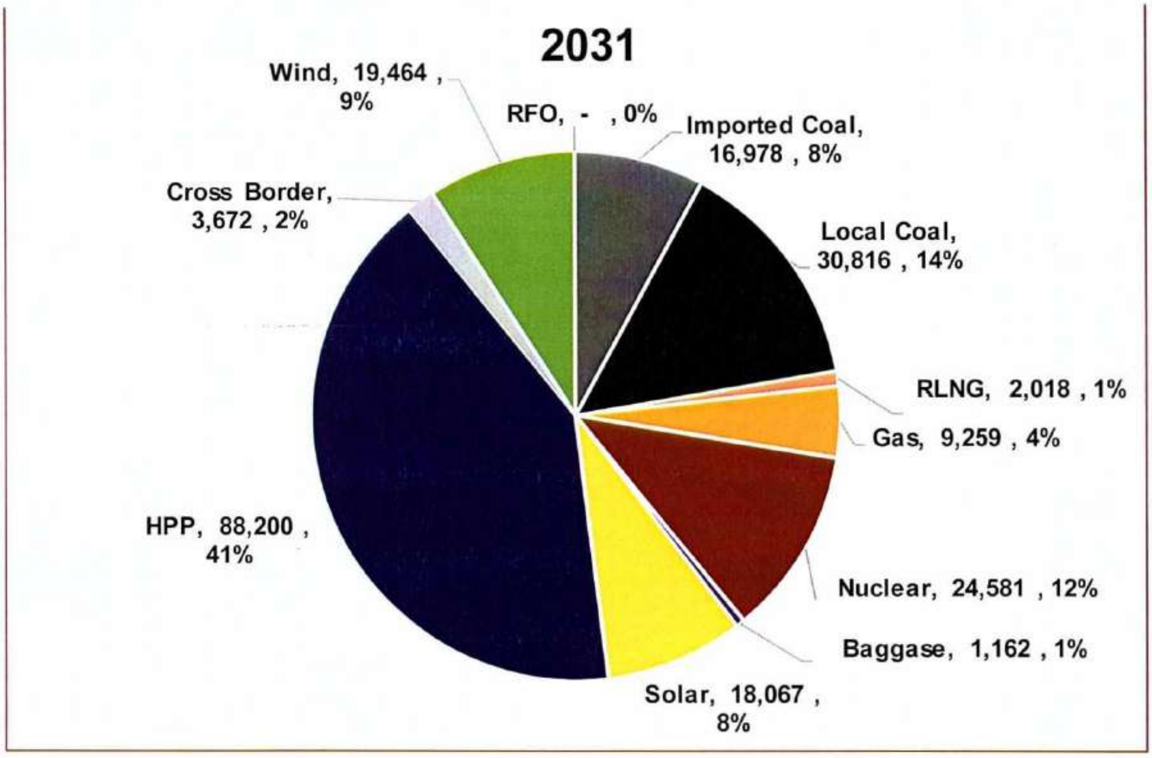


Chart C-3: IGCEP Generation Mix 2031 (GWh)

C-8. IGCEP Generation Mix 2022-31 (MW)

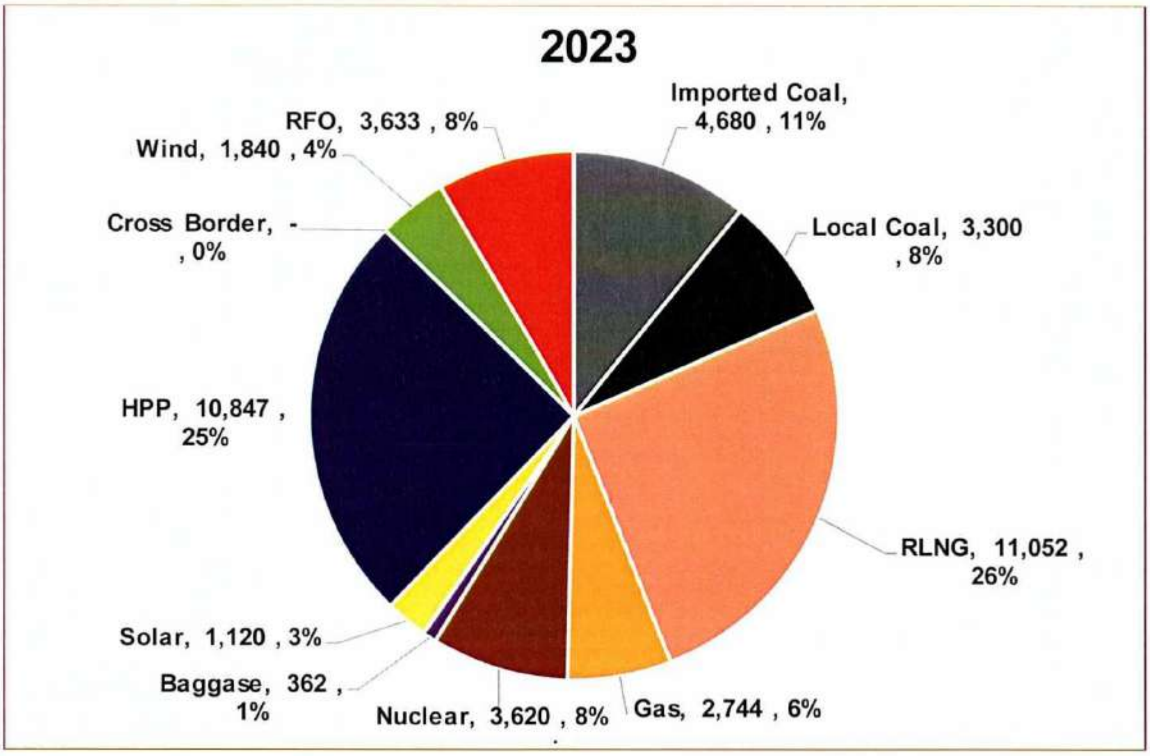


Chart C-4: IGCEP Generation Mix 2023 (MW)

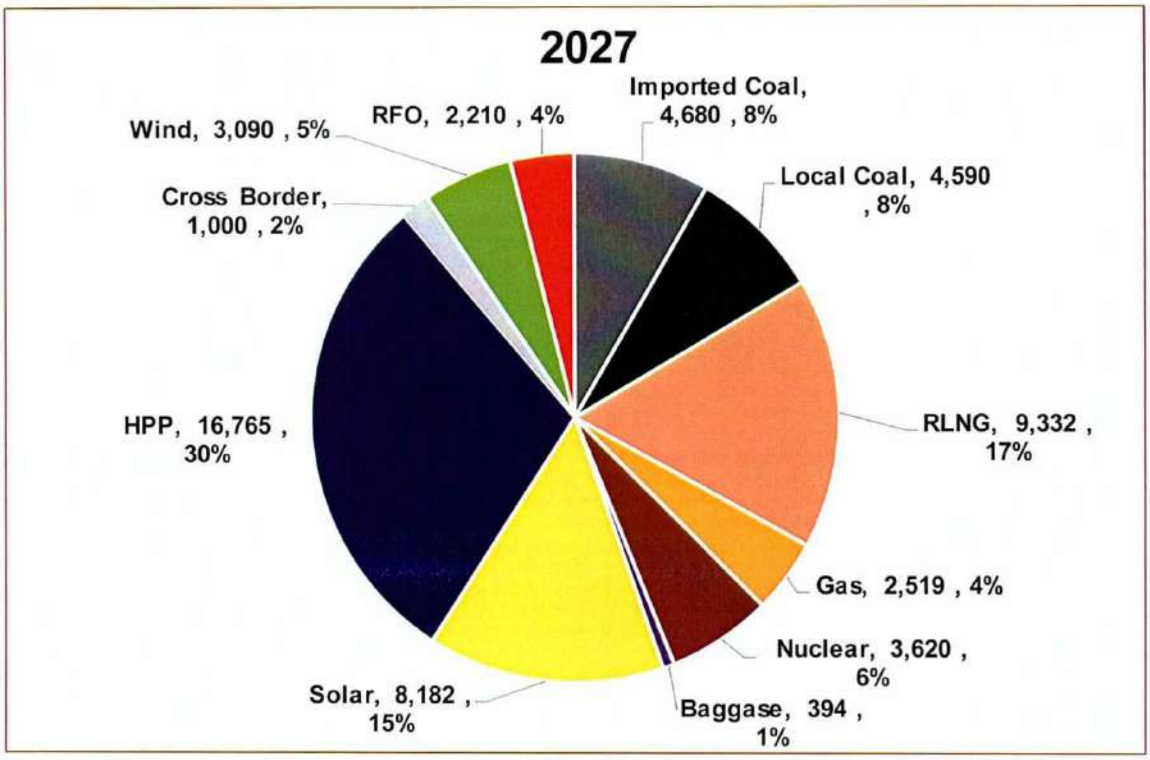


Chart C-5: IGCEP Generation Mix 2027 (MW)

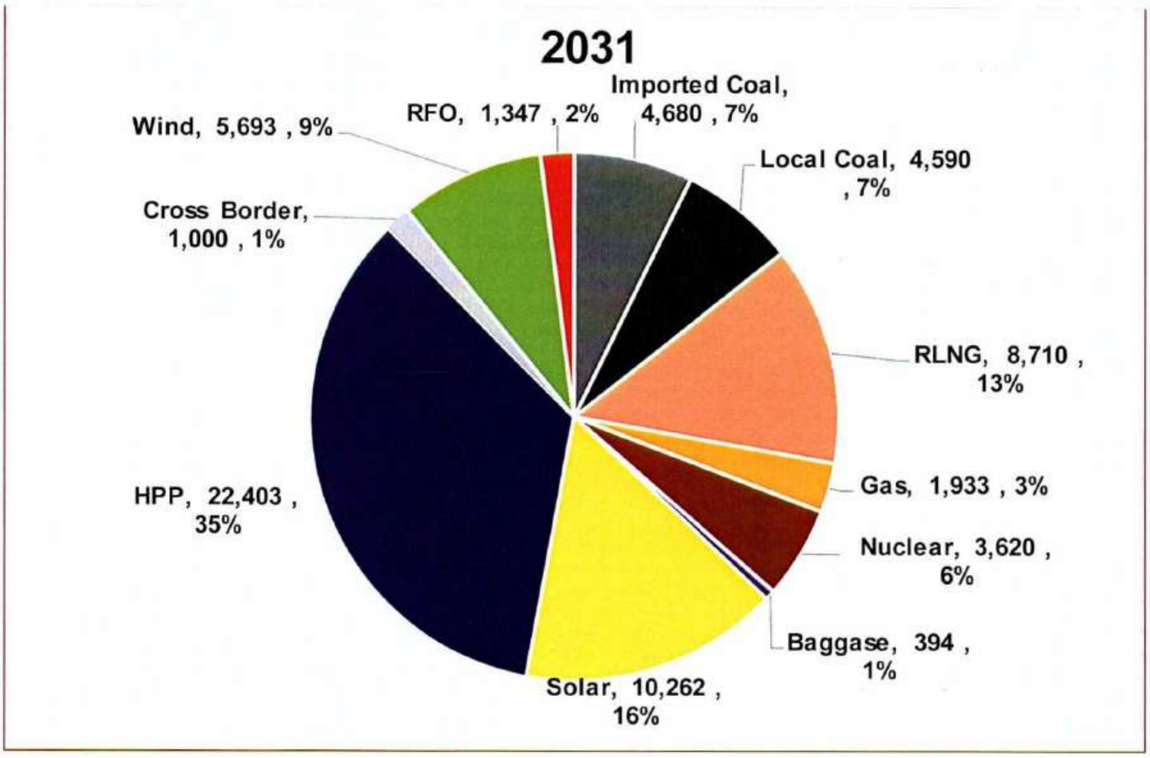
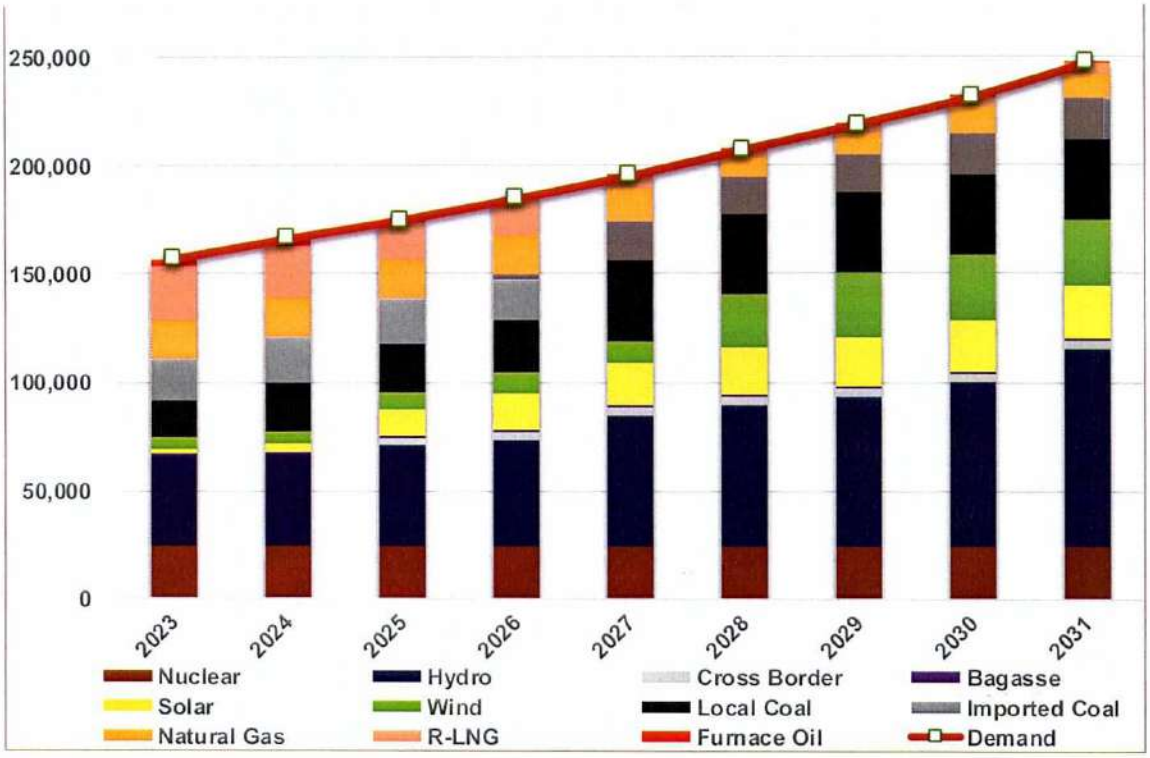


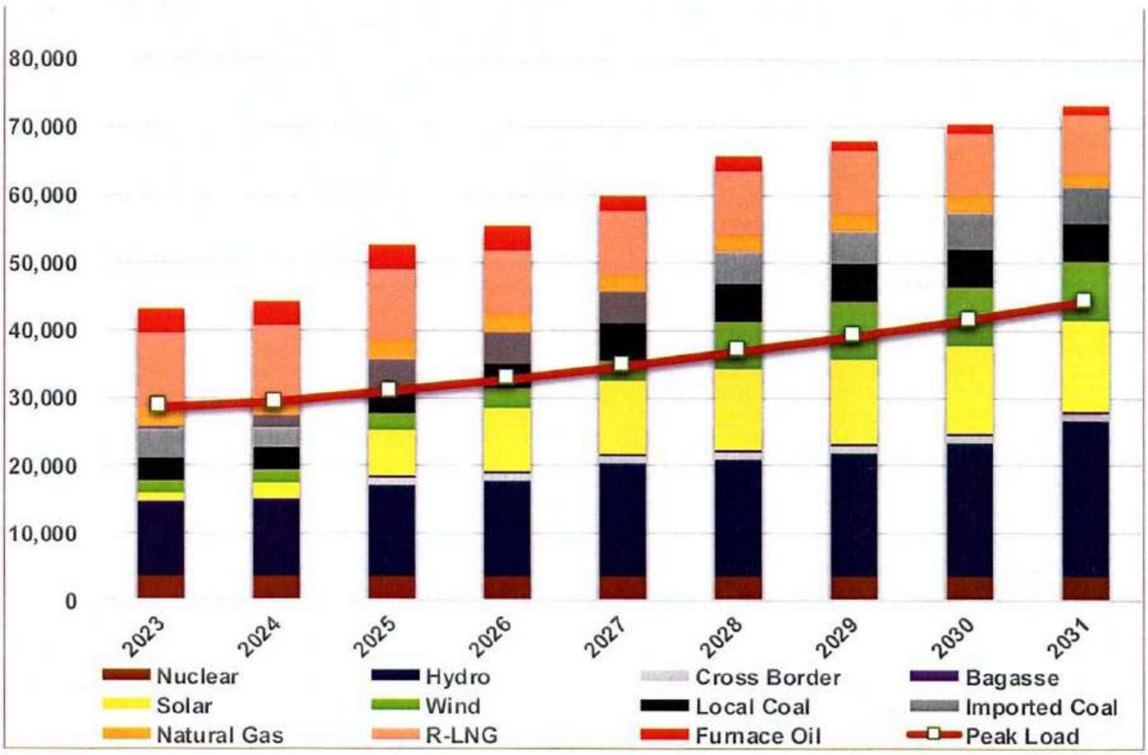
Chart C-6: IGCEP Generation Mix 2031 (MW)

Annexure D. High Demand Scenario

D-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



D-2. Installed Capacity Vs Peak Demand (MW) - Country



D-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Imported Coal	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	-	13	-	1,300	750	150	500	50	-	2,763	7,842
2027	-	990	990	-	-	945	-	150	-	50	-	3,125	10,967
2028	-	-	-	-	-	727	-	150	3,998	50	-	4,925	15,892
2029	-	-	-	401	-	-	-	150	1,529	50	-	2,130	18,022
2030	660	-	-	993	82	-	-	150	-	50	-	1,935	19,957
2031	-	-	-	2,430	-	-	-	150	-	50	-	2,630	22,587
Total	**660**	**990**	**990**	**3,846**	**82**	**6,092**	**2,000**	**1,050**	**6,527**	**350**	**-**	**22,587**	

D-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
Generation Additions in 2021-22 (MW)			20	20			
Cumulative Addition up till 2021-22 (MW)			20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
Generation Additions in 2022-23 (MW)			4,640	4,421			
Cumulative Addition up till 2023 (MW)			4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2023-24				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
			2024-25				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
	Generation Additions in 2024-25 (MW)		8,337	8,337			
	Cumulative Addition up till 2025 (MW)		14,590	14,371			
			2025-26				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-25
7	New_Solar_Utility	Solar	1,300	1,300	Yet to be determined	Optimized	Jul-25
8	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
9	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25
11	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
12	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
13	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
Generation Additions in 2025-26 (MW)			4,073	4,046			
Cumulative Addition up till 2026 (MW)			18,663	18,417			
2026-27							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
7	New_Solar_Utility	Solar	945	945	Yet to be determined	Optimized	Jul-26
8	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
9	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
10	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
11	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
12	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
13	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
14	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
15	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
16	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
17	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
Generation Additions in 2026-27 (MW)			6053	5897			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
Cumulative Addition up till 2027 (MW)			24,716	24,314			
2027-28							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Solar_Utility	Solar	727	727	Yet to be determined	Optimized	Jul-27
5	New_Wind	Wind	3,998	3,998	Yet to be determined	Optimized	Jul-27
6	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
7	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
8	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			5,840	5,840			
Cumulative Addition up till 2028 (MW)			30,556	30,154			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	Chowkel Khwar	Hydro	60	60	PEDO	Optimized	Jul-28
4	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
5	Harigehl-Majeedgala	Hydro	40.3	40.3	AJK-PPC	Optimized	Jul-28
6	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
7	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
8	New_Wind	Wind	1,529	1,529	Yet to be determined	Optimized	Jul-28
9	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
10	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
11	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
12	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
13	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
14	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			3,025	3,025			
Cumulative Addition up till 2029 (MW)			33,581	33,179			
2029-30							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Jamshoro Coal (U #2)	Imported Coal	660	627	GENCO	Optimized	Jul-29
7	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
8	Kalam Asrit	Hydro	238	238	PEDO	Optimized	Jul-29
9	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
10	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
11	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
12	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
13	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
14	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
15	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
16	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
17	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			2,756	2,723			
Cumulative Addition up till 2030 (MW)			36,337	35,902			
2030-31							

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
1	Ashkot	Hydro	300	300	PPIB	Optimized	Jul-30
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
Generation Additions in 2030-31 (MW)			3,849	3,849			
Cumulative Addition up till 2031 (MW)			40,186	39,751			

D-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.33	6.20	6.13	5.95	5.90
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.16	20.17	20.17
12	Access_Solar	PV	0.00	20.16	20.17	20.17	20.17	20.11	20.16	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.93	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.18	19.19	19.19
16	Helios	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.32	23.33	23.33
17	HNDS	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.32	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.32	23.33	23.33
19	Meridian	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.32	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.07	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.06	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	19.99	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.16	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.32	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.49	21.50	21.50
27	Zorlu	PV	0.00	20.16	20.17	20.17	20.17	20.11	20.16	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.68	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	37.07	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.68	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	36.85	37.19

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.54	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.68	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	37.82	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.20	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.66	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.54	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	37.81	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.68	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.17	41.28	41.28	41.28	41.17	40.85	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	36.85	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
66	Western	Wind	0.00	37.19	37.19	37.19	37.19	37.09	37.15	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.68	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.66	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.05	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.69	55.78
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Ashkot	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.58
79	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
80	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.76	54.76	54.79
81	Chowkel Khwar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	44.57	44.57	44.57
82	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
83	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
84	Harigehl-Majeedgala	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	63.43	63.43	63.47
85	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
86	Kalam Asrit	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.41	44.41
87	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
88	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
89	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
90	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
91	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94
92	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
93	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
94	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.27
95	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.85	51.90
96	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	54.06	52.77
97	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	40.75	41.21	41.21	41.21
98	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
99	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
100	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.80	42.83	42.83
101	Jagran-II	HPP Committed	50.53	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
102	Karot	HPP Committed	44.39	44.29	44.39	44.39	44.39	44.29	44.38	44.38	44.39
103	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
104	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
105	Koto	HPP Committed	57.12	57.08	57.24	57.19	57.19	56.96	57.12	57.12	57.23
106	Lawi	HPP Committed	0.00	47.99	48.10	48.05	48.05	47.90	47.99	47.99	48.08
107	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
108	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	42.71	42.60	42.71	42.71	42.71
109	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
110	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
111	Chamfall	HPP Committed	0.00	49.12	49.12	49.12	49.12	48.99	49.12	49.12	49.12
112	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.59	73.66	73.57	73.59	73.62	73.66
113	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
114	Deg Outfall	HPP Committed	76.29	76.09	76.29	76.29	76.29	76.09	76.26	76.29	76.29
115	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
116	Karora	HPP Committed	67.55	67.57	67.62	67.55	67.55	67.42	67.48	67.48	67.58
117	Kathai-II	HPP Committed	0.00	0.00	60.37	60.37	60.37	60.21	60.37	60.37	60.37
118	Kurram Tangi	HPP Committed	0.00	17.01	17.05	17.05	17.05	17.01	17.05	17.05	17.05
119	Riali-II	HPP Committed	0.00	53.15	53.17	53.16	53.16	53.01	53.15	53.15	53.16
120	Allai Khwar	HPP Existing	44.32	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
121	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
122	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
123	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
124	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
125	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
126	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
127	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
128	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
129	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
130	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
131	Mangla	HPP Existing	64.98	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
132	Neelum Jehlum	HPP Existing	51.65	51.54	51.69	51.69	51.69	51.54	51.65	51.67	51.69
133	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
134	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
135	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
136	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
137	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
138	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
139	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.73	70.05	35.75	31.48	31.28	27.60
140	Foundation	CCGT_Gas	89.97	90.25	89.99	89.98	82.20	57.94	57.94	80.23	76.05
141	Guddu-I	CCGT_Gas	36.90	74.63	74.43	74.42	68.17	17.48	21.27	66.63	65.02
142	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
143	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	72.41	53.56	55.19	68.72	69.08
144	Liberty	CCGT_Gas	75.60	75.02	74.53	73.40	0.00	0.00	0.00	0.00	0.00
145	Uch	CCGT_Gas	86.08	86.32	86.08	85.73	69.44	43.39	43.74	47.73	0.00
146	Uch-II	CCGT_Gas	87.77	88.05	87.80	87.78	79.24	51.33	51.33	51.31	51.32
147	SNPC-I	KE_CCGT_Gas	91.98	92.25	92.00	91.98	83.22	39.42	41.21	68.03	46.21
148	SNPC-II	KE_CCGT_Gas	91.98	92.25	92.00	91.99	84.04	41.09	43.06	83.67	67.44
149	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
158	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
159	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.29
160	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Engro 127MW	DG_RFO	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.01	0.01
162	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
163	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
164	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
165	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.23
166	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
168	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
169	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
170	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
171	K-2	Nuclear	85.06	85.30	85.07	85.06	85.06	85.28	85.02	85.03	85.05
172	K-3	Nuclear	85.66	85.90	85.67	85.66	85.66	85.88	85.61	85.63	85.65
173	Engro Thar	Local Coal	82.51	82.74	82.51	82.51	82.07	79.87	79.08	78.26	77.24
174	Gwadar	Local Coal	0.00	0.00	0.00	69.18	82.20	79.88	78.88	77.50	77.08
175	Lucky	Local Coal	85.08	85.31	85.08	85.08	85.07	85.01	84.18	84.48	85.07
176	NEW_L.Coal 660	Local Coal	0.00	0.00	0.00	0.00	83.33	82.95	82.16	82.46	83.04
177	New_L.Coal II	Local Coal	0.00	0.00	0.00	0.00	83.33	82.98	82.46	82.46	83.15
178	Thal Nova	Local Coal	49.35	85.21	84.98	84.98	84.93	82.51	82.63	82.55	80.94
179	Thar TEL	Local Coal	84.98	85.21	84.98	84.98	84.97	82.65	82.39	82.85	80.20
180	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	83.81	83.31	83.69	83.95
181	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.33	82.85	82.49	82.65	82.77
182	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
183	Jamshoro Coal	Imported Coal	49.36	85.12	85.00	84.39	28.53	14.78	18.50	21.57	24.33
184	Jamshoro Coal 2	Imported Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.94	23.37
185	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
186	Sahiwal Coal	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
187	FPCL	KE_Imported Coal	82.15	78.35	22.08	52.08	16.18	11.18	14.79	15.33	20.34
188	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26
189	Balloki	CCGT_RLNG	4.53	2.57	1.61	3.96	2.67	1.12	1.70	1.43	1.46
190	Bhikki	CCGT_RLNG	1.31	0.86	0.33	1.27	0.84	0.32	1.03	1.05	1.15
191	FKPCL	CCGT_RLNG	0.04	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.30	0.30	0.30	0.50
193	Haveli	CCGT_RLNG	11.75	7.12	5.64	8.46	4.91	1.71	2.41	2.35	3.49
194	KAPCO 1	CCGT_RLNG	35.31	35.38	35.30	0.00	0.00	0.00	0.00	0.00	0.00
195	KAPCO 2	CCGT_RLNG	11.86	11.83	11.87	0.00	0.00	0.00	0.00	0.00	0.00
196	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
197	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.02	0.00	0.29	0.29	0.30
198	Orient	CCGT_RLNG	37.73	23.29	0.00	0.55	0.30	0.30	0.30	0.39	0.61
199	Rousch	CCGT_RLNG	0.31	0.48	0.00	0.09	0.00	0.00	0.12	0.29	0.00
200	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.00	0.30	0.30	0.31
201	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.01	0.30	0.30	0.61
202	Trimmu	CCGT_RLNG	28.57	29.71	16.10	15.93	9.10	3.73	6.15	6.53	8.16
203	BQPS2	KE_CCGT_RLNG	85.44	83.90	49.93	78.73	19.29	10.35	14.37	14.80	16.07
204	BQPS3	KE_CCGT_RLNG	89.91	89.93	85.67	83.88	31.37	21.86	24.23	26.22	28.94
205	KCCPP	KE_CCGT_RLNG	85.31	82.63	24.86	27.46	12.02	8.95	10.97	13.75	14.43
206	KTGTPS	KE_CCGT_RLNG	45.54	42.45	10.17	13.51	7.92	2.86	4.77	6.24	7.22
207	SGTPS	KE_CCGT_RLNG	48.76	45.65	10.69	14.14	8.34	3.55	5.29	6.39	8.43
208	BQPS1-U1	KE_ST_RLNG	11.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
209	BQPS1-U5	KE_ST_RLNG	30.31	32.47	2.00	2.89	0.99	1.22	1.58	1.72	2.45

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
210	BQPS1-U6	KE_ST_RLNG	17.13	17.52	1.54	1.99	0.56	0.92	1.46	1.52	2.04
211	BQPS1-U2	KE_GT_RLNG	23.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

D-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
Jun-22	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	3,120	-	-	-	2,773	55,482
2027	1,980	2,558	-	-	-	1,515	-225	-1,292	-	4,536	60,018
2028	-	545	-	-	-	5,295	-	-131	-	5,709	65,727
2029	-	926	-	-	-	2,099	-	-727	-	2,298	68,025
2030	-	1,526	-172	-	660	570	-	-136	-	2,448	70,472
2031	-	3,279	-450	-	-	570	-586	-	-	2,813	73,285
Total	**5,580**	**23,041**	**8,710**	**3,620**	**5,340**	**22,714**	**1,933**	**1,347**	**1,000**	**32,025**	**73,285**

D-7. IGCEP Generation Mix 2023-2031 (GWh)

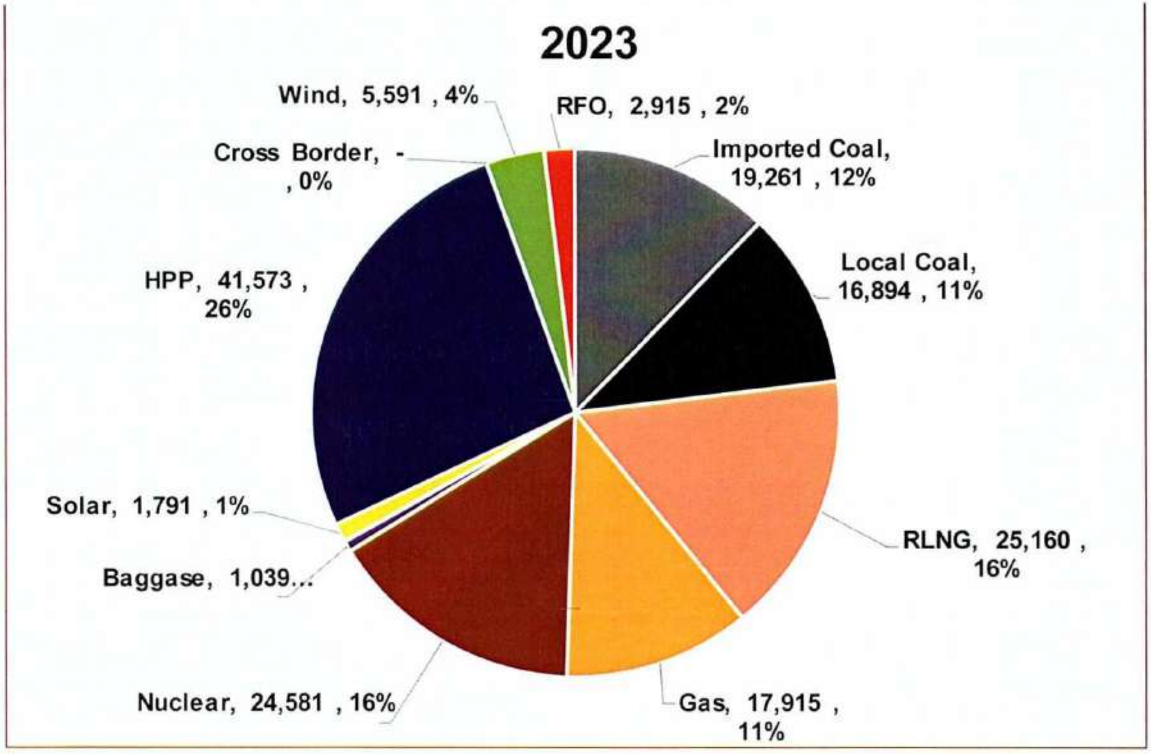


Chart D-1: IGCEP Generation Mix 2023 (GWh)

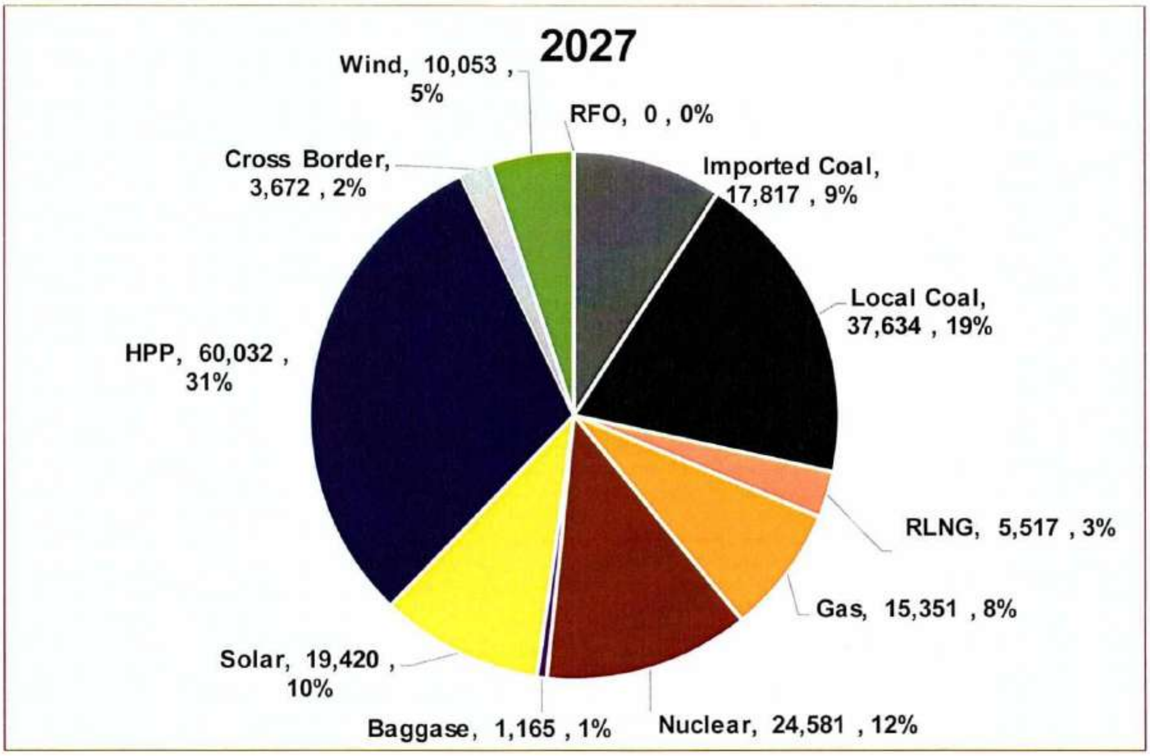


Chart D-2: IGCEP Generation Mix 2027 (GWh)

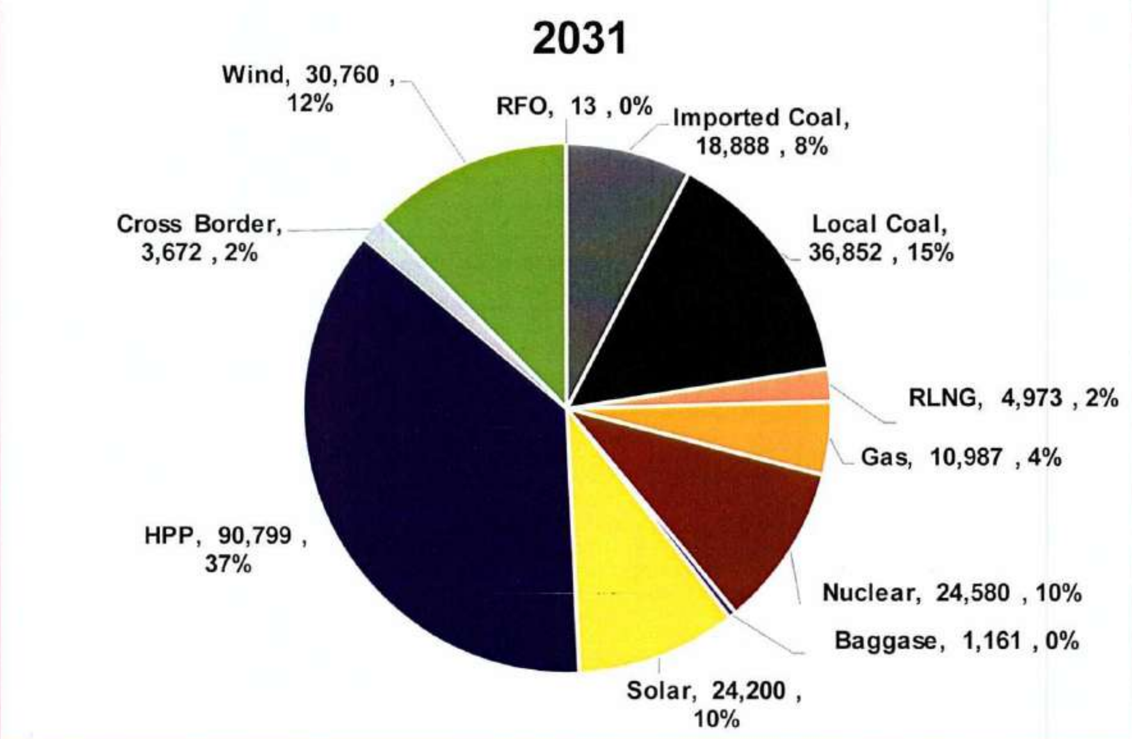


Chart D-3: IGCEP Generation Mix 2031 (GWh)

D-8. IGCEP Generation Mix 2023-31 (MW)

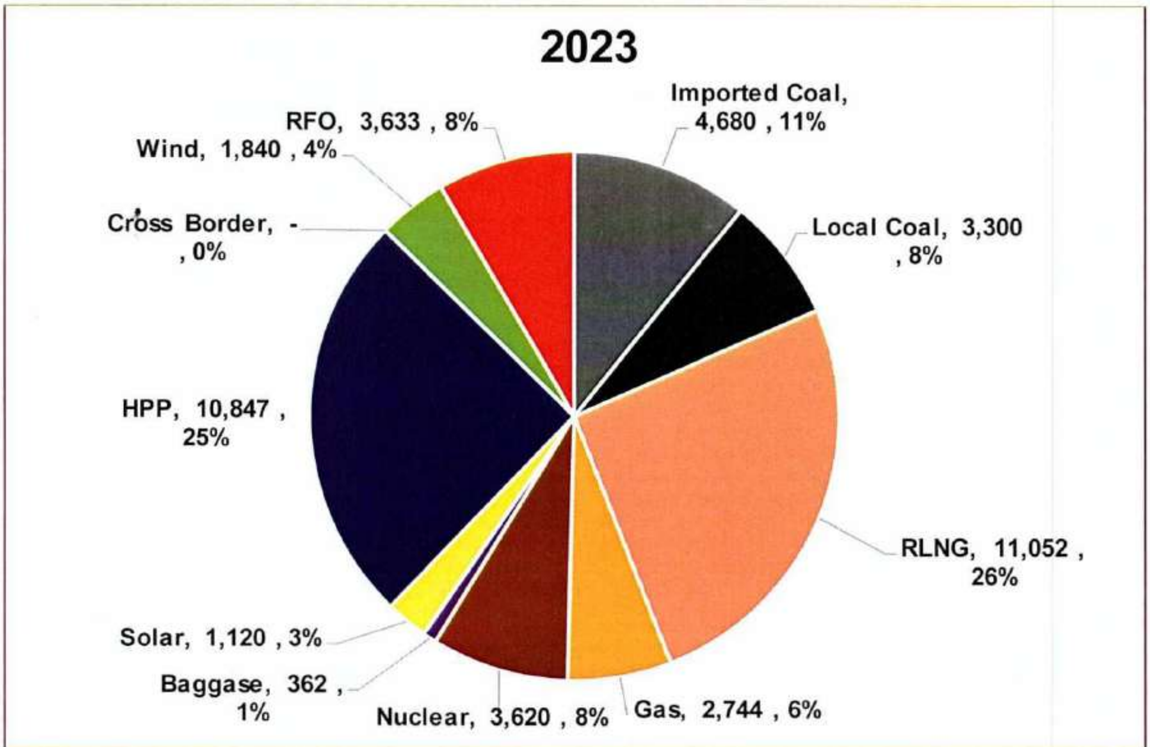


Chart D-4: IGCEP Generation Mix 2023 (MW)

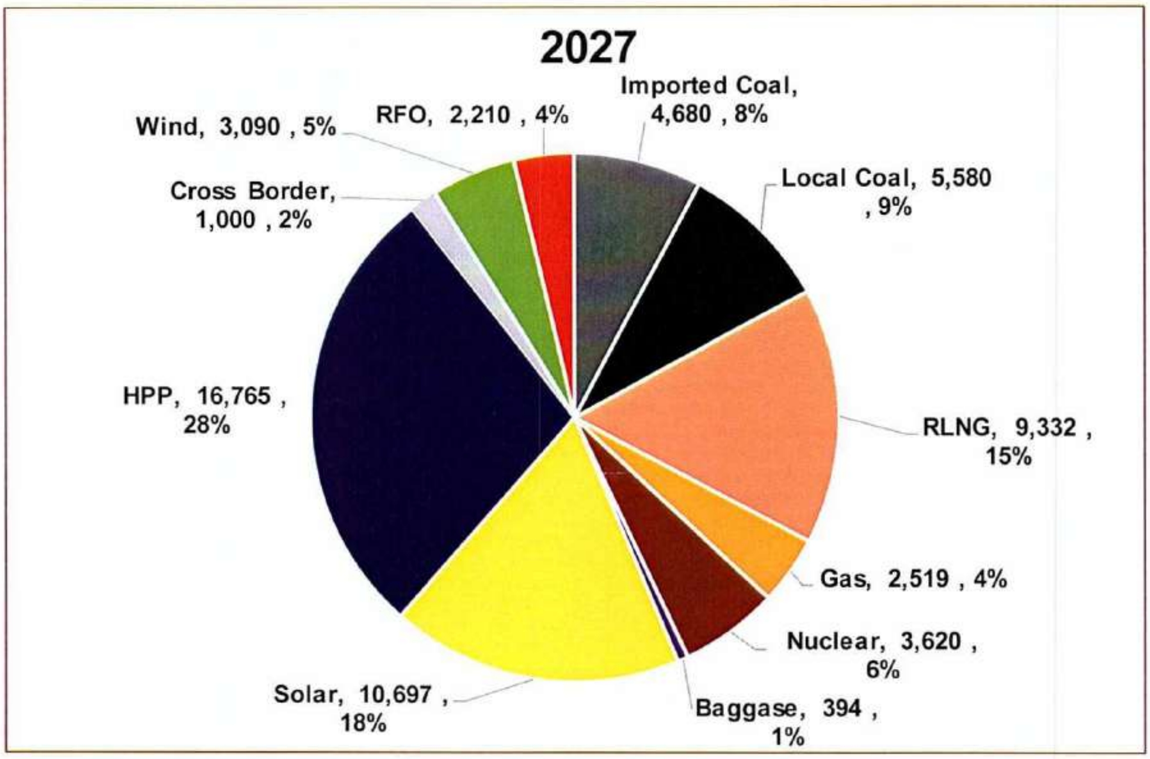


Chart D-5: IGCEP Generation Mix 2027 (MW)

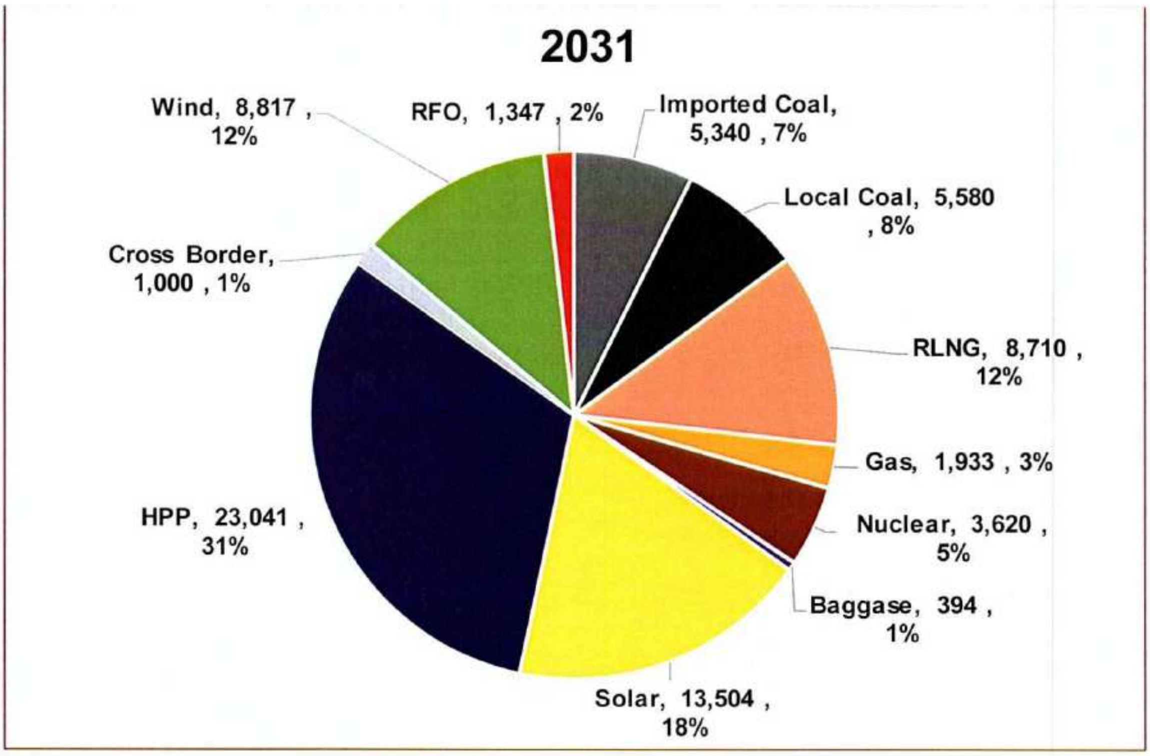
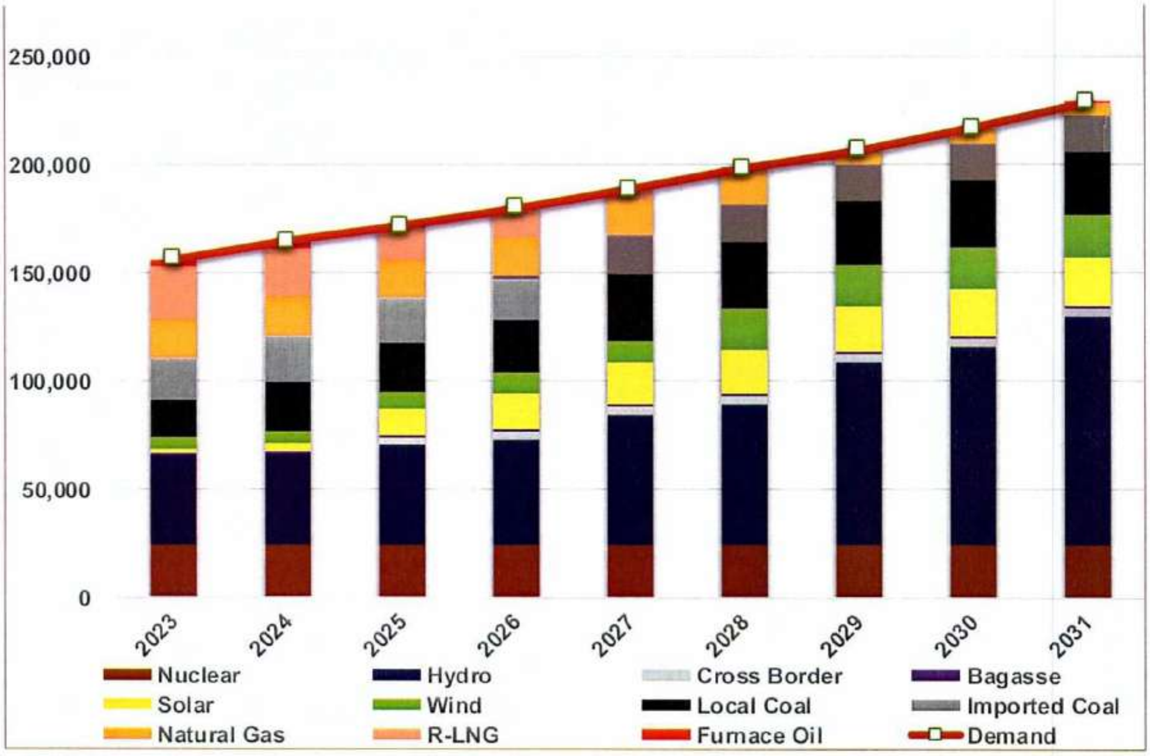


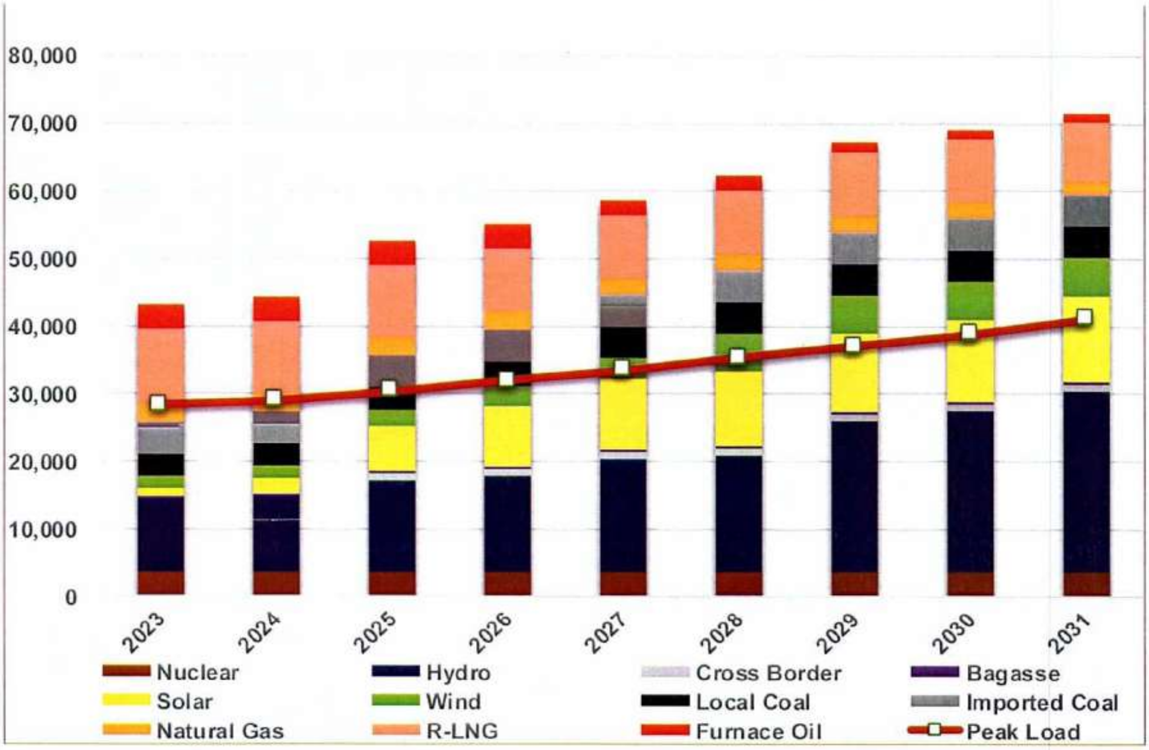
Chart D-6: IGCEP Generation Mix 2031 (MW)

Annexure E. Diamer Bhasha HPP in 2029

E-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



E-2. Installed Capacity Vs Peak Demand (MW) - Country



E-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	13	-	1,300	477	150	500	50	-	2,490	7,569
2027	-	990	-	-	1,047	-	150	-	50	-	2,237	9,806
2028	-	-	-	-	-	-	150	2,524	50	-	2,724	12,530
2029	-	-	4,535*	-	-	-	150	-	50	-	4,735	17,265
2030	-	-	989	82	-	-	150	-	50	-	1,271	18,537
2031	-	-	2,130	-	-	-	150	-	50	-	2,330	20,867
Total	**-**	**990**	**7,676**	**82**	**5,467**	**1,727**	**1,050**	**3,524**	**350**	**-**	**20,867**	

**4,200 MW Diamer Bhasha HPP has been represented here.*

E-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
	Generation Additions in 2021-22 (MW)		20	20			
	Cumulative Addition up till 2021-22 (MW)		20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
	Generation Additions in 2022-23 (MW)		4,640	4,421			
	Cumulative Addition up till 2023 (MW)		4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2023-24							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
2024-25							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			8,337	8,337			
Cumulative Addition up till 2025 (MW)			14,590	14,371			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_DG	Solar	477	477	Yet to be determined	Optimized	Jul-25
7	New_Solar_Utility	Solar	1,300	1,300	Yet to be determined	Optimized	Jul-25
8	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
9	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25
11	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
12	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
13	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
Generation Additions in 2025-26 (MW)			3,800	3,773			
Cumulative Addition up till 2026 (MW)			18,390	18,144			
2026-27							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Solar_Utility	Solar	1,047	1,047	Yet to be determined	Optimized	Jul-26
7	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
8	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
9	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
10	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
11	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
12	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
13	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
14	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
15	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
16	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
Generation Additions in 2026-27 (MW)			5165	5087			
Cumulative Addition up till 2027 (MW)			23,555	23,231			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2027-28				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	2,524	2,524	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			3,639	3,639			
Cumulative Addition up till 2028 (MW)			27,194	26,870			
			2028-29				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
3	Diamer Bhasha	Hydro	4500	4500	WAPDA	Committed with Cost	Jul-28
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
6	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
7	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
8	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
9	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			5,631	5,631			
Cumulative Addition up till 2029 (MW)			32,824	32,500			
			2029-30				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29

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#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-29
5	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
6	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
7	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
8	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
9	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
10	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-29
15	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
16	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
17	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			2,092	2,092			
Cumulative Addition up till 2030 (MW)			34,916	34,592			
2030-31							
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
	Generation Additions in 2030-31 (MW)		3,549	3,549			
	Cumulative Addition up till 2031 (MW)		38,465	38,141			

E-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.38	6.35	1.12	2.33	1.18
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.27	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.27	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.27	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.17	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.82	55.82
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.79	54.79
80	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
81	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
82	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
83	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
84	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
85	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
86	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
87	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
88	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02
89	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.34
90	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.90	51.90
91	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	52.77	52.77
92	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
93	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
94	Diamer Bhasha	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	43.71	43.71	43.71
95	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
96	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.83	42.83	42.83
97	Jagran-II	HPP Committed	50.39	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
98	Karot	HPP Committed	44.38	44.29	44.39	44.39	44.39	44.29	44.39	44.39	44.39
99	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	52.07	52.07	52.07	52.07
100	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
101	Koto	HPP Committed	56.96	57.08	57.24	57.19	57.19	56.96	57.24	57.24	57.24
102	Lawi	HPP Committed	0.00	48.10	48.10	48.05	48.05	47.90	48.10	48.10	48.10
103	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
104	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	46.36	42.60	42.71	42.71	42.71
105	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
106	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.02	10.05	10.05	10.02	10.05	10.05	10.05
107	Chamfall	HPP Committed	0.00	48.99	49.12	49.12	49.12	48.99	49.12	49.12	49.12
108	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.66	73.66	73.57	73.66	73.66	73.66
109	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
110	Deg Outfall	HPP Committed	76.26	76.09	76.29	76.29	76.29	76.09	76.29	76.29	76.29
111	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
112	Karora	HPP Committed	67.55	67.57	67.62	67.55	67.55	67.42	67.62	67.62	67.62
113	Kathai-II	HPP Committed	0.00	0.00	60.21	60.37	60.37	60.21	60.37	60.37	60.37
114	Kurram Tangi	HPP Committed	0.00	17.01	17.05	17.05	17.05	17.01	17.05	17.05	17.05
115	Riali-II	HPP Committed	0.00	53.01	53.17	53.16	53.16	53.01	53.17	53.17	53.17
116	Allai Khwar	HPP Existing	44.32	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
117	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
118	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
119	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
120	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
121	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
122	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
123	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
124	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
125	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
126	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
127	Mangla	HPP Existing	64.94	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
128	Neelum Jehlum	HPP Existing	51.69	51.54	51.69	51.69	51.69	51.54	51.69	51.69	51.69
129	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
130	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
131	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
132	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
133	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
134	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
135	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.73	70.05	36.48	28.93	25.26	21.71
136	Foundation	CCGT_Gas	89.97	90.25	90.00	89.97	82.50	81.89	57.94	57.94	57.94
137	Guddu-I	CCGT_Gas	36.90	74.63	74.43	74.42	69.45	70.21	7.50	8.17	7.44
138	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
139	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	74.25	73.19	8.94	10.52	9.15
140	Liberty	CCGT_Gas	74.86	75.02	46.06	68.11	0.00	0.00	0.00	0.00	0.00
141	Uch	CCGT_Gas	86.08	86.32	86.08	85.53	79.97	43.82	39.95	40.53	0.00
142	Uch-II	CCGT_Gas	87.77	88.05	87.81	87.66	79.96	61.98	51.33	51.33	51.33
143	SNPC-I	KE_CCGT_Gas	91.98	92.25	91.96	91.98	84.07	83.70	28.41	26.75	27.34
144	SNPC-II	KE_CCGT_Gas	91.98	92.25	91.96	91.98	84.07	83.70	29.97	27.94	29.09
145	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
146	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
147	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
156	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01
158	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
159	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
160	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
164	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
165	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
166	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
167	K-2	Nuclear	85.06	85.30	85.07	85.06	85.06	85.29	85.07	85.07	85.07
168	K-3	Nuclear	85.66	85.90	85.67	85.66	85.66	85.89	85.67	85.67	85.67
169	Engro Thar	Local Coal	82.51	82.74	82.51	82.50	82.35	82.07	79.73	80.03	74.89
170	Gwadar	Local Coal	0.00	0.00	0.00	69.18	82.75	81.67	27.73	79.84	14.18
171	Lucky	Local Coal	85.08	85.31	85.08	85.07	85.07	85.31	85.08	85.08	85.08
172	Thal Nova	Local Coal	49.35	85.21	84.98	84.97	84.97	84.61	84.27	83.92	82.57
173	Thar TEL	Local Coal	84.98	85.21	84.98	84.97	84.97	84.61	84.10	84.08	82.40
174	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	84.69	84.58	84.82	84.76

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
175	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.33	83.54	83.34	83.34	83.34
176	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
177	Jamshoro Coal	Imported Coal	49.36	84.04	83.89	81.27	32.33	19.25	6.47	7.10	7.27
178	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
179	Sahiwal Coal	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
180	FPCL	KE_Imported Coal	82.15	77.13	18.09	19.12	10.94	11.45	3.32	3.19	7.81
181	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182	Balloki	CCGT_RLNG	4.19	2.02	0.96	1.88	2.02	0.72	0.00	0.00	0.00
183	Bhikki	CCGT_RLNG	1.20	0.78	0.00	0.52	0.57	0.29	0.00	0.00	0.00
184	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
185	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.00	0.00	0.00	0.00
186	Haveli	CCGT_RLNG	10.92	5.77	3.29	5.07	4.10	1.75	0.20	0.17	0.18
187	KAPCO 1	CCGT_RLNG	35.31	35.38	35.25	0.00	0.00	0.00	0.00	0.00	0.00
188	KAPCO 2	CCGT_RLNG	11.86	11.83	11.89	0.00	0.00	0.00	0.00	0.00	0.00
189	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
190	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.00	0.00
191	Orient	CCGT_RLNG	37.73	23.25	0.00	0.00	0.30	0.00	0.00	0.00	0.00
192	Rousch	CCGT_RLNG	0.24	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
194	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.13	0.00	0.00	0.00	0.00
195	Trimmu	CCGT_RLNG	26.05	20.80	12.24	11.79	8.36	4.05	0.67	0.50	0.36
196	BQPS2	KE_CCGT_RLNG	85.21	83.46	29.63	26.94	16.95	9.45	2.90	2.93	7.04
197	BQPS3	KE_CCGT_RLNG	89.81	89.80	79.57	83.16	29.45	19.94	10.15	12.69	15.27
198	KCCPP	KE_CCGT_RLNG	85.10	82.46	22.09	18.28	11.52	8.58	2.21	2.13	2.28
199	KTGTPS	KE_CCGT_RLNG	45.16	40.73	8.23	9.95	6.21	2.91	1.56	1.24	1.55
200	SGTPS	KE_CCGT_RLNG	48.00	44.44	9.14	10.62	6.96	3.16	1.59	1.26	1.76
201	BQPS1-U1	KE_ST_RLNG	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	BQPS1-U5	KE_ST_RLNG	29.34	30.27	1.66	1.71	0.46	0.77	0.72	0.75	1.10
203	BQPS1-U6	KE_ST_RLNG	16.15	15.84	1.43	1.54	0.30	0.13	0.30	0.46	0.67
204	BQPS1-U2	KE_GT_RLNG	22.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

E-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
Jun-22	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	2,847	-	-	-	2,500	55,209
2027	990	2,558	-	-	-	1,617	-225	-1,292	-	3,648	58,857
2028	-	545	-	-	-	3,094	-	-131	-	3,508	62,365
2029	-	5,061	-	-	-	570	-	-727	-	4,904	67,268
2030	-	1,522	-172	-	-	570	-	-136	-	1,784	69,052
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	71,565
Total	**4,590**	**26,871**	**8,710**	**3,620**	**4,680**	**18,813**	**1,933**	**1,347**	**1,000**	**30,304**	**71,565**

E-7. IGCEP Generation Mix 2023-2031 (GWh)

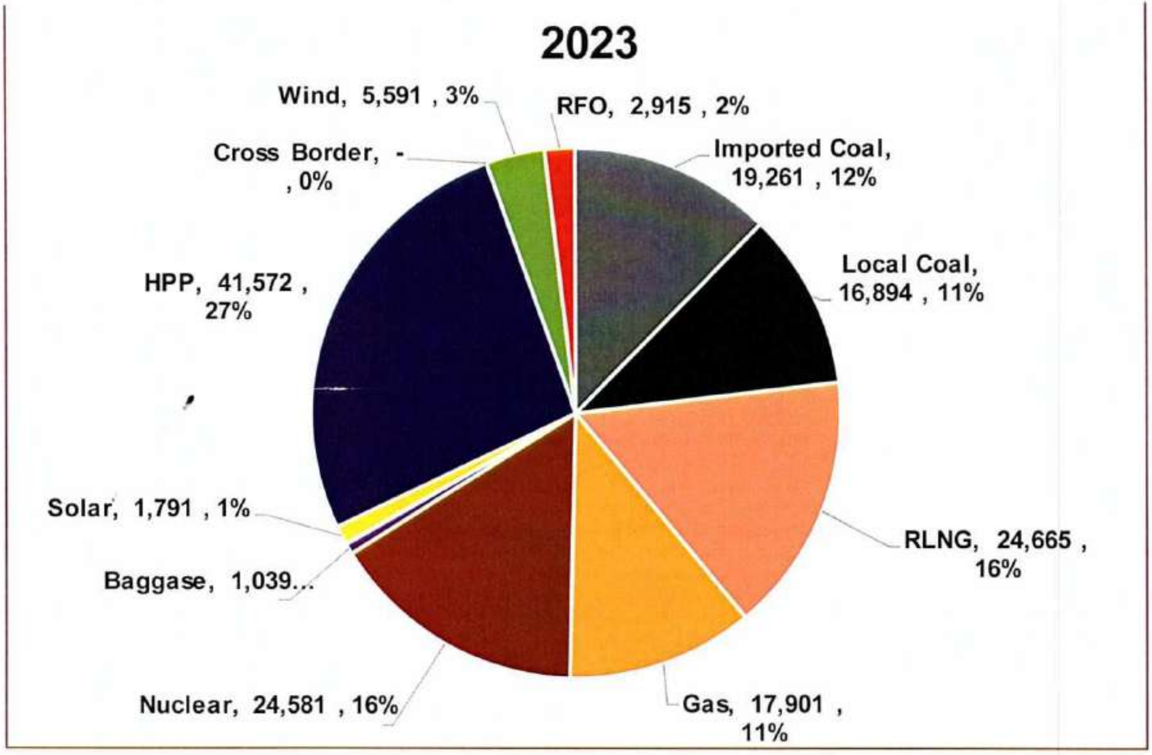


Chart E-1: IGCEP Generation Mix 2023 (GWh)

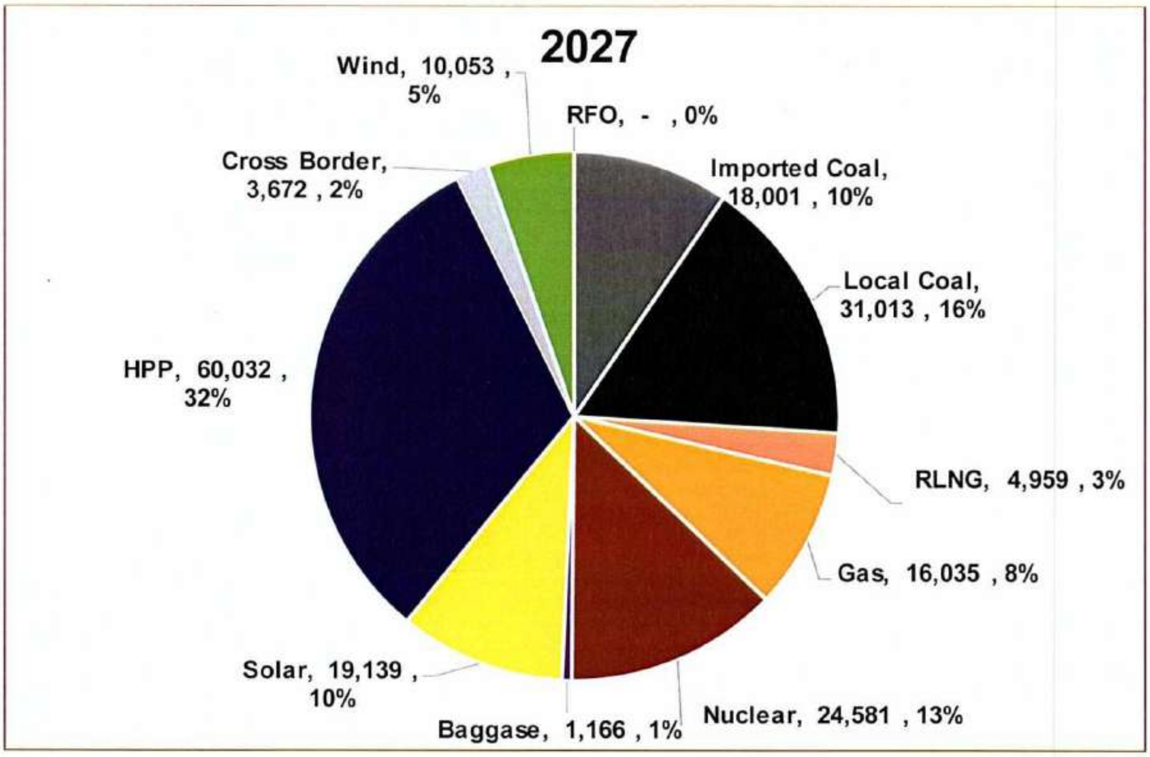


Chart E-2: IGCEP Generation Mix 2027 (GWh)

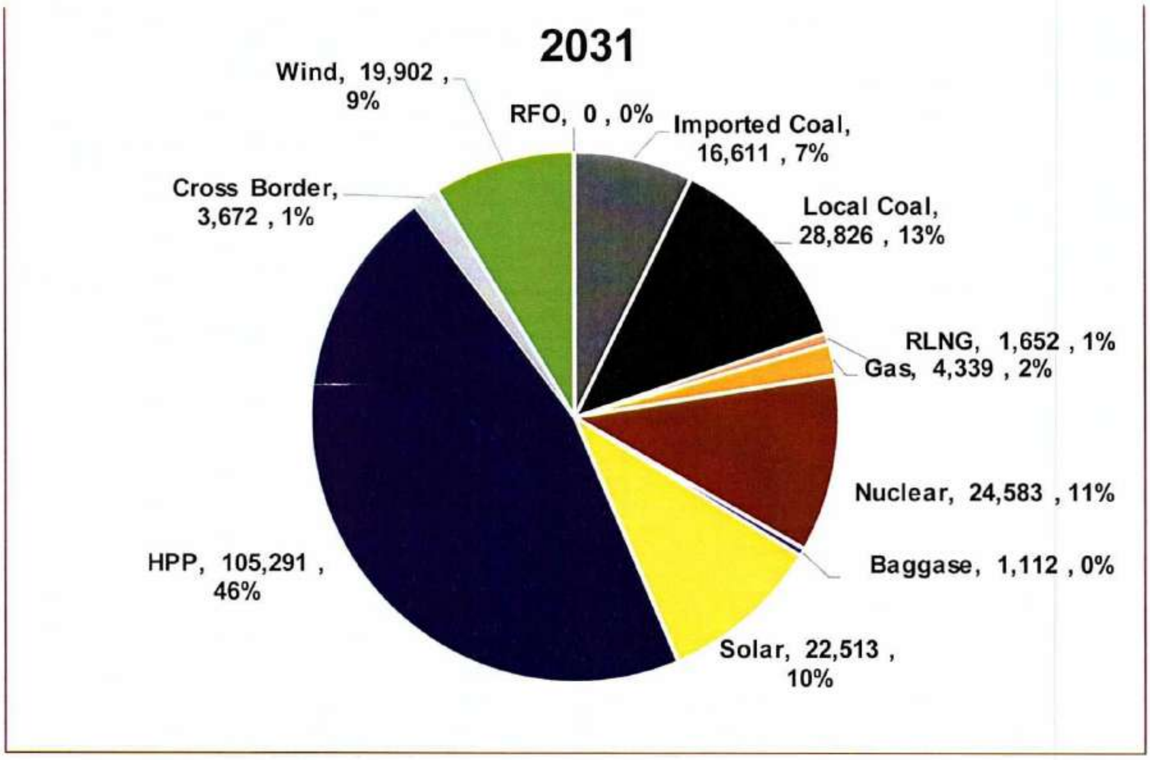


Chart E-3: IGCEP Generation Mix 2031 (GWh)

E-8. IGCEP Generation Mix 2023-31 (MW)

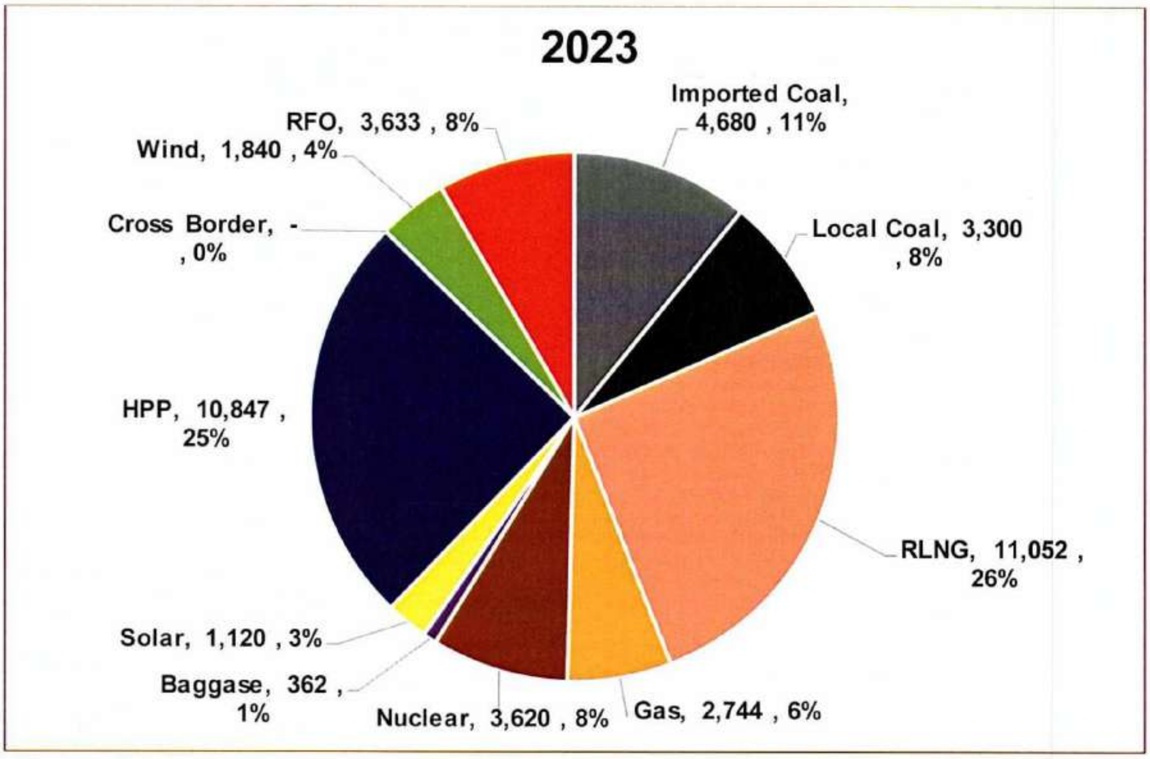


Chart E-4: IGCEP Generation Mix 2023 (MW)

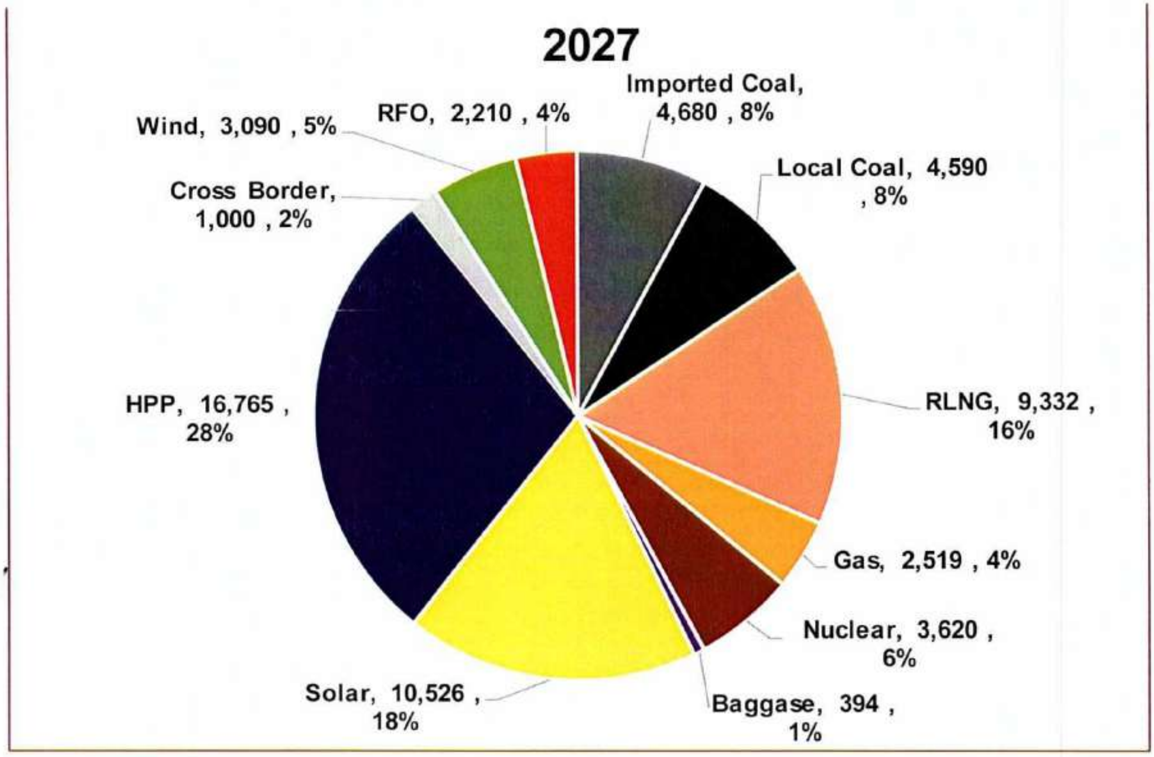


Chart E-5: IGCEP Generation Mix 2027 (MW)

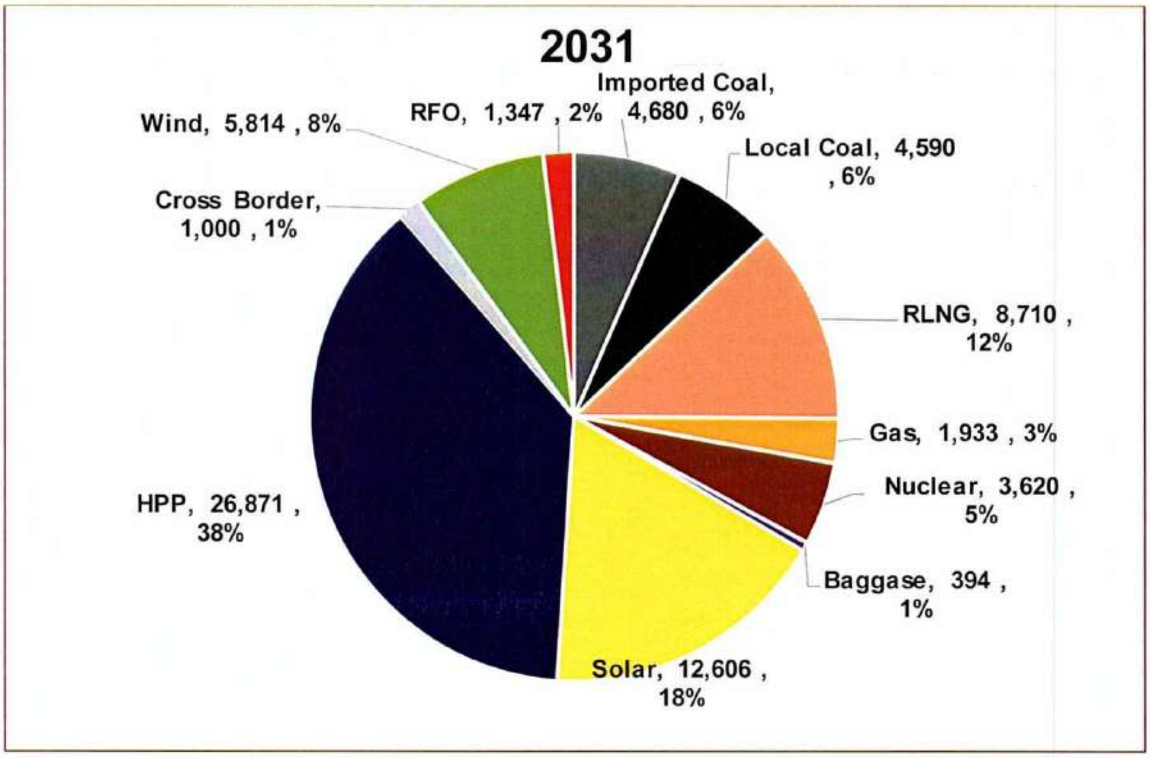
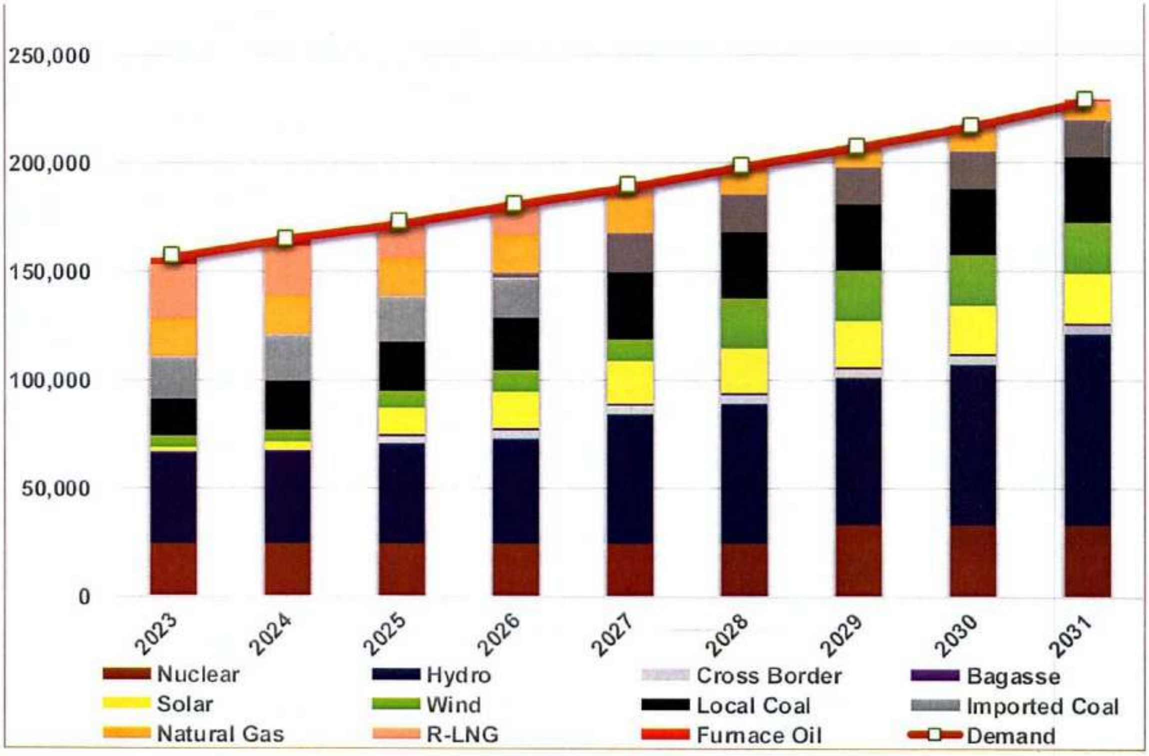


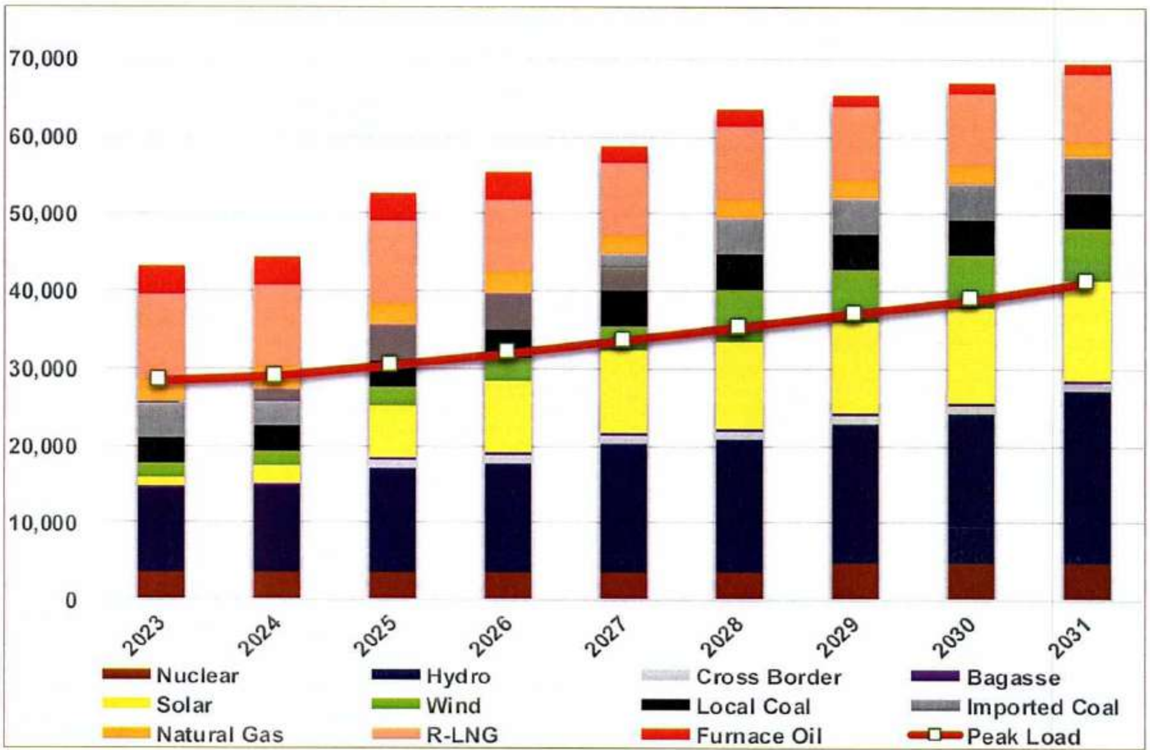
Chart E-6: IGCEP Generation Mix 2031 (MW)

Annexure F. Chashma Nuclear (C-5) for Energy Security

F-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



F-2. Installed Capacity Vs Peak Demand (MW) - Country



F-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	Nuclear	HPP	HPP KE	Solar Utility MWp	Solar Feeder MWp	Solar KE MWp	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	-	13	-	1,300	750	150	500	50	-	2,763	7,842
2027	-	990	-	-	-	900	-	150	-	50	-	2,090	9,932
2028	-	-	-	-	-	-	-	150	3,595	50	-	3,795	13,727
2029	-	-	1,200	300	-	-	-	150	-	50	-	1,700	15,428
2030	-	-	-	755	82	-	-	150	-	50	-	1,037	16,465
2031	-	-	-	2,130	-	-	-	150	-	50	-	2,330	18,795
Total	**-**	**990**	**1,200**	**3,208**	**82**	**5,320**	**2,000**	**1,050**	**4,595**	**350**	**-**	**18,795**	

F-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
Generation Additions in 2021-22 (MW)			20	20			
Cumulative Addition up till 2021-22 (MW)			20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
Generation Additions in 2022-23 (MW)			4,640	4,421			
Cumulative Addition up till 2023 (MW)			4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2023-24				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
			2024-25				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			8,337	8,337			
Cumulative Addition up till 2025 (MW)			14,590	14,371			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-25
7	New_Solar_Utility	Solar	1,300	1,300	Yet to be determined	Optimized	Jul-25
8	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
9	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25
11	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
12	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
13	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
Generation Additions in 2025-26 (MW)			4,073	4,046			
Cumulative Addition up till 2026 (MW)			18,663	18,417			
2026-27							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Solar_Utility	Solar	900	900	Yet to be determined	Optimized	Jul-26
7	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
8	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
9	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
10	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
11	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
12	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
13	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
14	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
15	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
16	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
Generation Additions in 2026-27 (MW)			5018	4940			
Cumulative Addition up till 2027 (MW)			23,681	23,357			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2027-28							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	3,595	3,595	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			4,710	4,710			
Cumulative Addition up till 2028 (MW)			28,391	28,067			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	C-5	Nuclear	1200	1,111	PAEC	Committed with Cost	Jul-28
4	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
5	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
6	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
7	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
8	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
9	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
10	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
11	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
12	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			2,596	2,507			
Cumulative Addition up till 2029 (MW)			30,987	30,574			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2029-30				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
8	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
9	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
10	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
15	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
16	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			1,858	1,858			
Cumulative Addition up till 2030 (MW)			32,844	32,431			
			2030-31				
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
Generation Additions in 2030-31 (MW)			3,549	3,549			
Cumulative Addition up till 2031 (MW)			36,393	35,980			

F-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.38	6.25	1.97	5.93	5.88
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.17	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.69	55.82
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.76	54.76	54.79
80	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
81	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
82	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
83	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
84	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
85	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
86	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
87	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
88	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
89	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
90	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.30
91	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.85	51.90
92	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	52.77	52.77
93	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
94	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
95	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
96	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.83	42.83	42.83
97	Jagran-II	HPP Committed	50.53	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
98	Karot	HPP Committed	44.39	44.29	44.39	44.39	44.39	44.29	44.38	44.39	44.39
99	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
100	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
101	Koto	HPP Committed	57.15	57.08	57.24	57.19	57.19	56.96	57.12	57.15	57.24
102	Lawi	HPP Committed	0.00	48.02	48.10	48.05	48.05	47.90	47.99	48.02	48.02
103	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
104	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	42.71	42.60	42.71	42.71	42.71
105	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
106	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
107	Chamfall	HPP Committed	0.00	48.99	49.12	49.12	49.12	48.99	49.12	49.12	49.12
108	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.62	73.66	73.57	73.62	73.66	73.66
109	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
110	Deg Outfall	HPP Committed	76.29	76.09	76.29	76.29	76.29	76.09	76.29	76.29	76.29
111	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
112	Karora	HPP Committed	67.55	67.57	67.62	67.55	67.55	67.42	67.48	67.51	67.62
113	Kathai-II	HPP Committed	0.00	0.00	60.21	60.37	60.37	60.21	60.37	60.37	60.37
114	Kurram Tangi	HPP Committed	0.00	17.01	17.05	17.05	17.05	17.01	17.05	17.05	17.05
115	Riali-II	HPP Committed	0.00	53.15	53.17	53.16	53.16	53.01	53.15	53.15	53.16
116	Allai Khwar	HPP Existing	44.25	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
117	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
118	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
119	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
120	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
121	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
122	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
123	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
124	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
125	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
126	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
127	Mangla	HPP Existing	64.98	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
128	Neelum Jehlum	HPP Existing	51.65	51.54	51.69	51.69	51.69	51.54	51.69	51.69	51.69
129	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
130	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
131	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
132	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
133	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
134	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
135	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.73	70.05	35.76	29.65	27.98	23.72
136	Foundation	CCGT_Gas	89.97	90.25	90.00	89.97	82.33	57.94	57.94	57.94	57.94
137	Guddu-I	CCGT_Gas	36.90	74.63	74.43	74.42	69.30	17.02	15.84	17.70	16.46
138	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
139	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	74.11	71.22	18.12	49.67	28.99
140	Liberty	CCGT_Gas	74.86	75.02	46.06	50.52	0.00	0.00	0.00	0.00	0.00
141	Uch	CCGT_Gas	86.08	86.32	86.08	85.47	79.86	43.53	41.67	43.47	0.00
142	Uch-II	CCGT_Gas	87.77	88.05	87.81	87.35	79.71	51.33	51.32	51.31	51.32
143	SNPC-I	KE_CCGT_Gas	91.98	92.25	91.96	91.81	84.07	33.81	33.13	31.93	33.02
144	SNPC-II	KE_CCGT_Gas	91.98	92.25	91.96	91.98	84.07	35.30	34.36	32.65	34.57
145	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
146	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
147	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
156	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
158	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
159	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
160	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
164	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
165	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
166	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
167	C-5	Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	89.02	89.19	89.19
168	K-2	Nuclear	85.06	85.30	85.07	85.06	85.06	85.29	85.05	85.05	85.05
169	K-3	Nuclear	85.66	85.90	85.67	85.66	85.66	85.89	85.65	85.65	85.65
170	Engro Thar	Local Coal	82.51	82.74	82.51	82.50	82.25	80.35	79.52	76.68	76.03
171	Gwadar	Local Coal	0.00	0.00	0.00	69.18	82.67	80.68	77.24	76.92	76.43
172	Lucky	Local Coal	85.08	85.31	85.08	85.07	85.07	85.04	84.48	84.75	84.99
173	Thal Nova	Local Coal	49.35	85.21	84.98	84.97	84.97	83.72	82.34	82.72	79.43
174	Thar TEL	Local Coal	84.98	85.21	84.98	84.97	84.97	83.73	82.16	82.08	79.93
175	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	84.38	83.67	84.12	82.87

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
176	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.33	83.02	82.62	82.74	82.73
177	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
178	Jamshoro Coal	Imported Coal	49.36	84.04	83.89	80.49	30.32	14.07	12.03	15.89	12.74
179	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
180	Sahiwal Coal	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
181	FPCL	KE_Imported Coal	82.15	77.13	18.09	18.37	10.94	9.63	8.57	10.87	10.18
182	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
183	Balloki	CCGT_RLNG	4.19	2.02	0.96	1.80	2.02	0.55	0.43	0.70	0.68
184	Bhikki	CCGT_RLNG	1.20	0.78	0.00	0.52	0.57	0.29	0.24	0.29	0.29
185	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
186	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.30	0.00	0.00	0.13	0.20
187	Haveli	CCGT_RLNG	10.92	5.77	3.29	5.01	4.10	1.50	1.32	1.33	1.16
188	KAPCO 1	CCGT_RLNG	35.31	35.38	35.25	0.00	0.00	0.00	0.00	0.00	0.00
189	KAPCO 2	CCGT_RLNG	11.86	11.83	11.89	0.00	0.00	0.00	0.00	0.00	0.00
190	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
191	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.00	0.00
192	Orient	CCGT_RLNG	37.73	23.25	0.00	0.00	0.30	0.00	0.00	0.30	0.30
193	Rousch	CCGT_RLNG	0.24	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
194	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
195	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.13	0.00	0.00	0.00	0.00
196	Trimmu	CCGT_RLNG	26.05	20.80	12.24	11.65	8.30	2.63	2.20	2.91	3.41
197	BQPS2	KE_CCGT_RLNG	85.21	83.46	29.63	25.80	16.55	8.28	6.83	8.25	9.53
198	BQPS3	KE_CCGT_RLNG	89.81	89.80	79.57	82.91	29.18	18.13	15.84	18.32	18.47
199	KCCPP	KE_CCGT_RLNG	85.10	82.46	22.09	18.23	11.49	5.95	4.71	6.32	8.90
200	KTGTPS	KE_CCGT_RLNG	45.16	40.73	8.23	9.95	6.21	2.59	2.79	2.74	2.79
201	SGTPS	KE_CCGT_RLNG	48.00	44.44	9.14	10.60	6.75	2.85	2.85	2.84	3.15
202	BQPS1-U1	KE_ST_RLNG	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
203	BQPS1-U5	KE_ST_RLNG	29.34	30.27	1.66	1.71	0.46	0.50	0.72	1.05	1.39
204	BQPS1-U6	KE_ST_RLNG	16.15	15.84	1.43	1.54	0.30	0.01	0.30	0.75	0.96
205	BQPS1-U2	KE_GT_RLNG	22.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

F-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
2022	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	3,120	-	-	-	2,773	55,482
2027	990	2,558	-	-	-	1,470	-225	-1,292	-	3,501	58,983
2028	-	545	-	-	-	4,165	-	-131	-	4,579	63,562
2029	-	826	-	1,200	-	570	-	-727	-	1,869	65,430
2030	-	1,288	-172	-	-	570	-	-136	-	1,550	66,980
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	69,493
Total	**4,590**	**22,403**	**8,710**	**4,820**	**4,680**	**20,010**	**1,933**	**1,347**	**1,000**	**28,232**	**69,493**

F-7. IGCEP Generation Mix 2023-2031 (GWh)

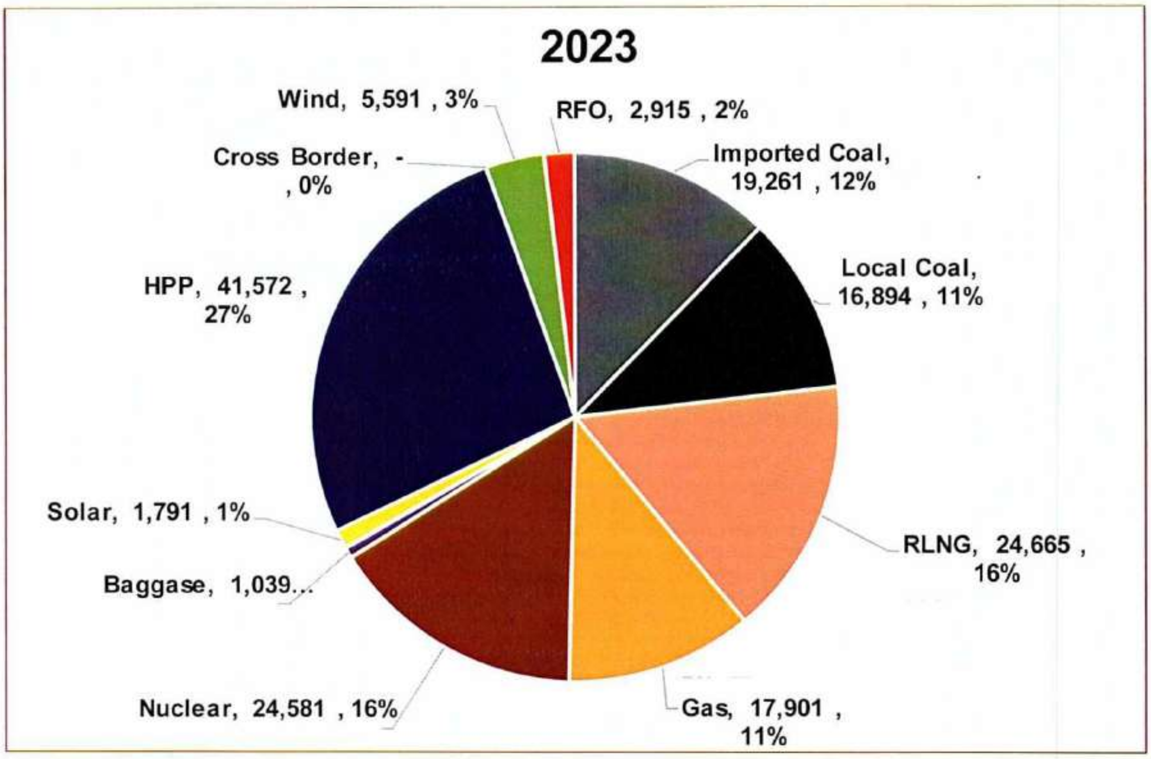


Chart F-1: IGCEP Generation Mix 2023 (GWh)

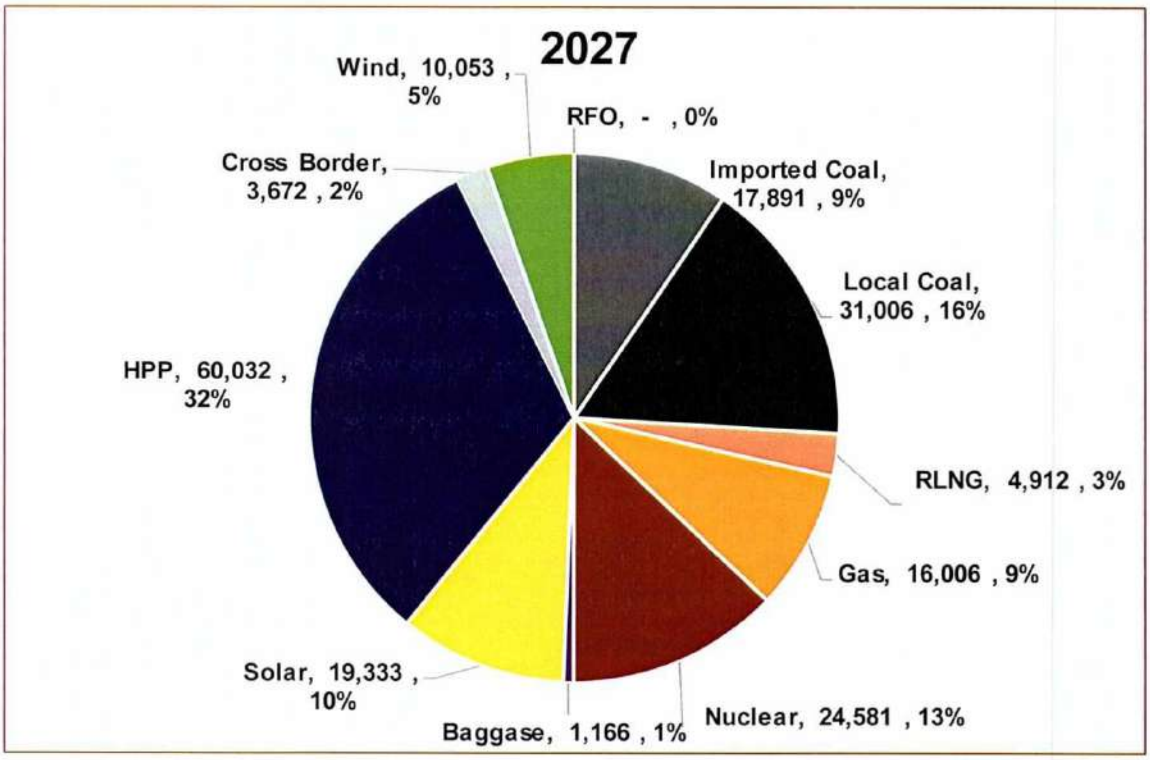


Chart F-2: IGCEP Generation Mix 2027 (GWh)

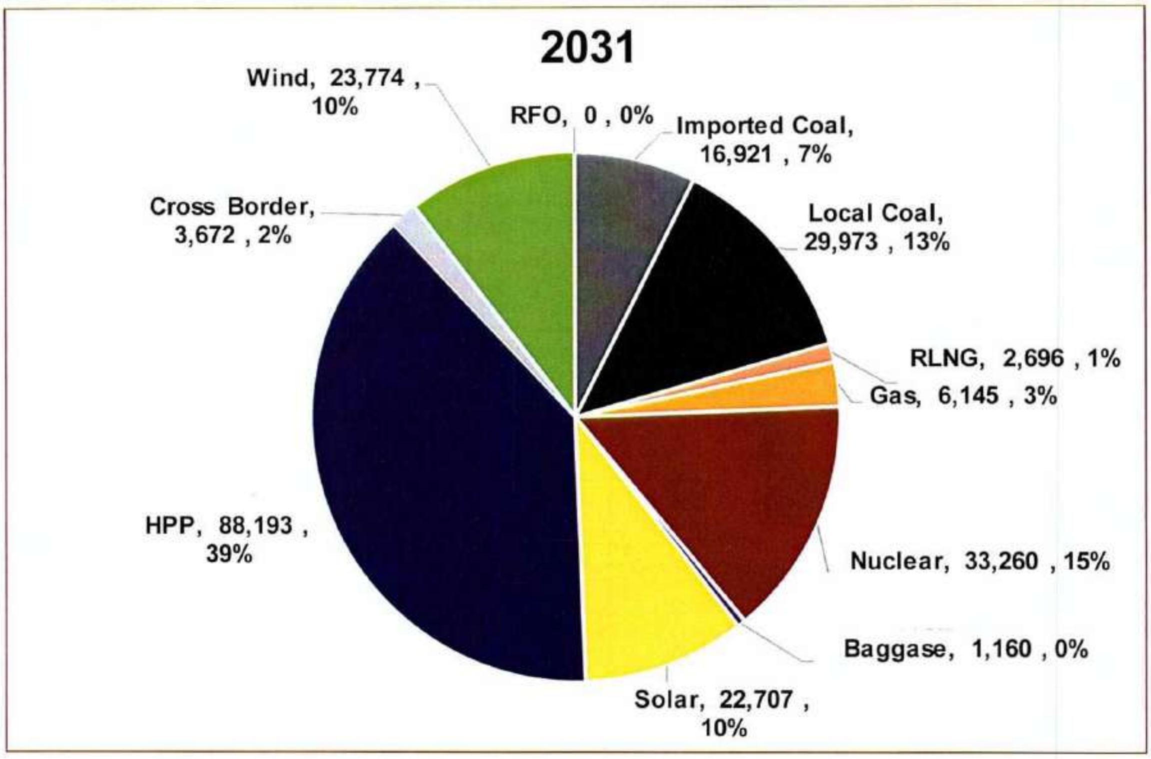


Chart F-3: IGCEP Generation Mix 2031 (GWh)

F-8. IGCEP Generation Mix 2023-31 (MW)

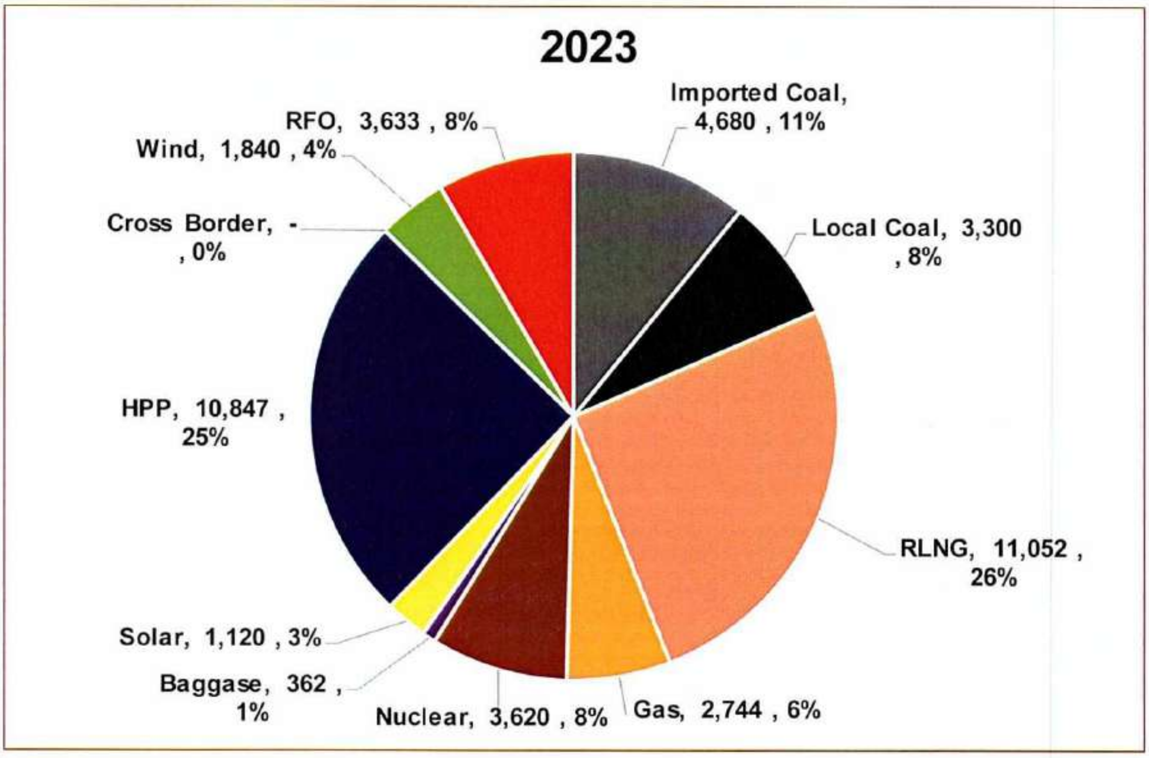


Chart F-4: IGCEP Generation Mix 2023 (MW)

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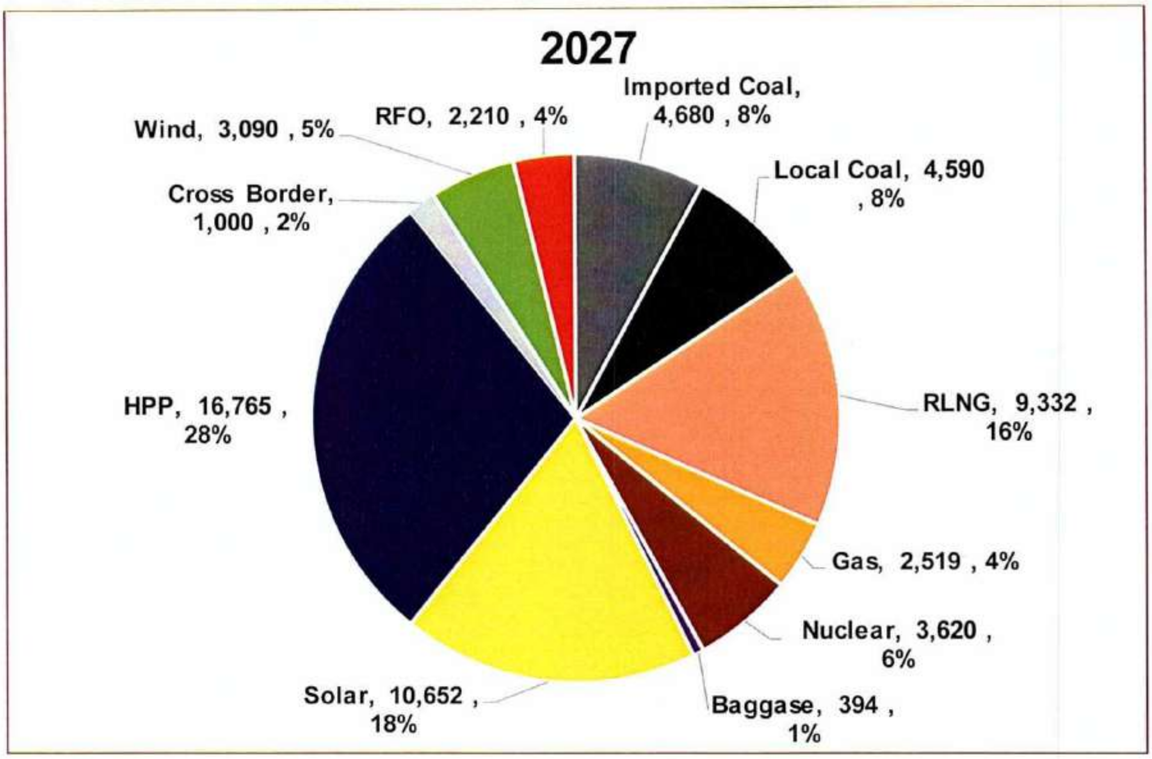


Chart F-5: IGCEP Generation Mix 2027 (MW)

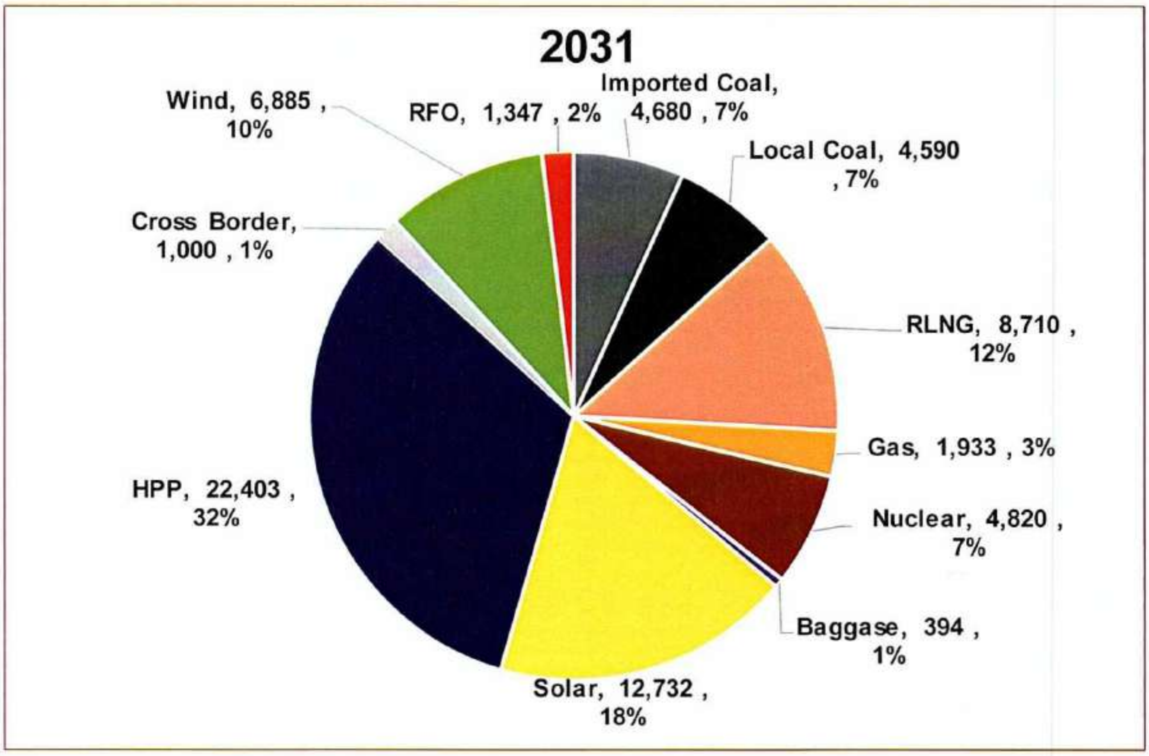
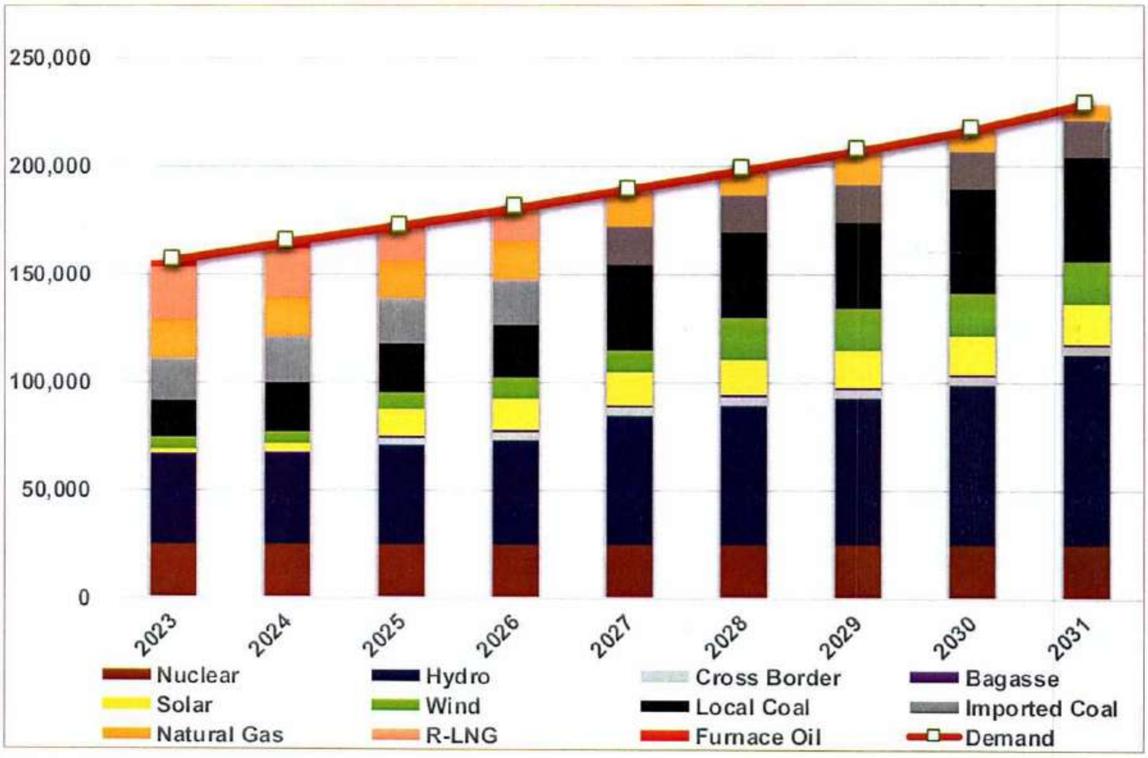


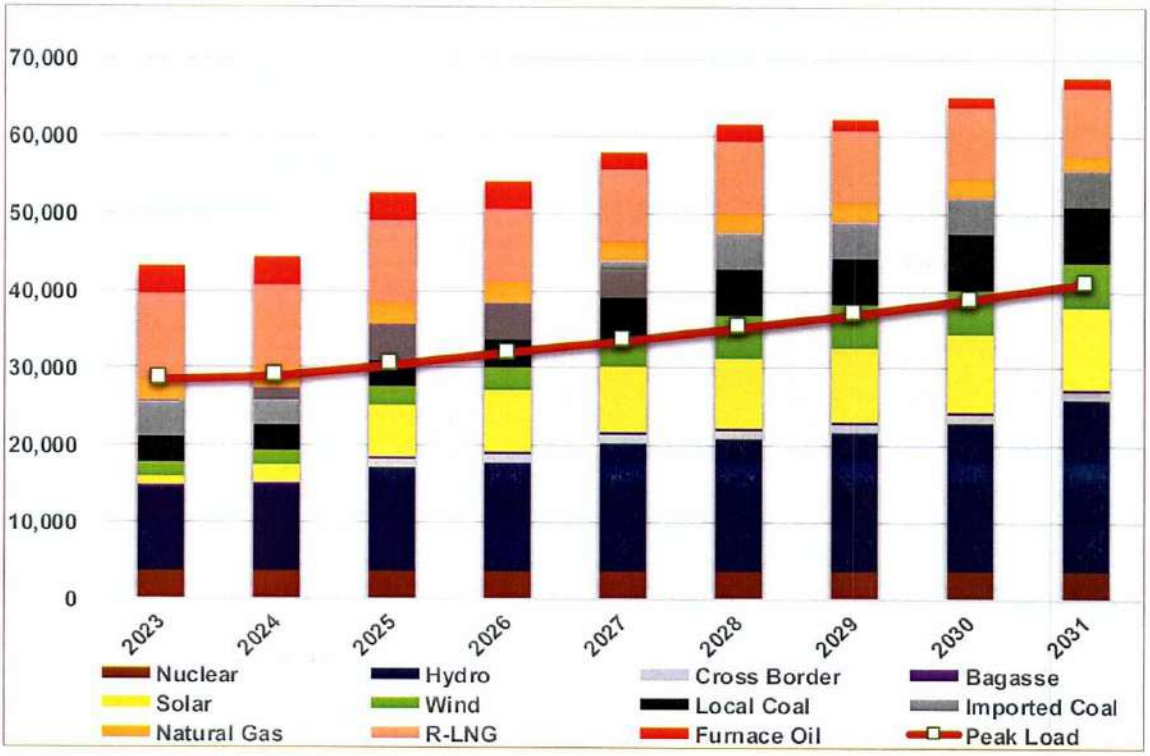
Chart F-6: IGCEP Generation Mix 2031 (MW)

Annexure G. Local Coal inclusion in 2027 and 2030

G-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



G-2. Installed Capacity Vs Peak Demand (MW) - Country



G-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	500	-	-	-	-	500	500
2025	-	-	10	-	3,120	750	150	500	50	-	4,580	5,080
2026	-	-	13	-	-	750	150	500	50	-	1,463	6,542
2027	1,320	990	-	-	-	-	150	-	50	-	2,510	9,052
2028	-	-	-	-	-	-	150	2,546	50	-	2,746	11,798
2029	-	-	300	-	-	-	150	-	50	-	500	12,299
2030	1,320	-	755	82	-	-	150	-	50	-	2,357	14,656
2031	-	-	2,130	-	-	-	150	-	50	-	2,330	16,986
Total	**2,640**	**990**	**3,208**	**82**	**3,120**	**2,000**	**1,050**	**3,546**	**350**	**-**	**16,986**	

G-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
	Generation Additions in 2021-22 (MW)		20	20			
	Cumulative Addition up till 2021-22 (MW)		20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
	Generation Additions in 2022-23 (MW)		4,640	4,421			
	Cumulative Addition up till 2023 (MW)		4,659	4,440			

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2023-24							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	500	500	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			1,594	1,594			
Cumulative Addition up till 2024 (MW)			6,253	6,034			
2024-25							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24

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#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-24
8	New_Solar_Utility	Solar	3,120	3,120	Yet to be determined	Optimized	Jul-24
9	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-24
10	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
11	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
12	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
13	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
14	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
15	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
16	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
17	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
18	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			8,337	8,337			
Cumulative Addition up till 2025 (MW)			14,590	14,371			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_DG	Solar	750	750	Yet to be determined	Optimized	Jul-25
7	New_Wind	Wind	500	500	Yet to be determined	Optimized	Jul-25
8	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25
9	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
10	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
11	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
12	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
	Generation Additions in 2025-26 (MW)		2,773	2,746			
	Cumulative Addition up till 2026 (MW)		17,363	17,117			
			2026-27				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Local Coal	Local Coal	1,320	1,214	Yet to be determined	Optimized	Jul-26
7	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
8	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
9	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
10	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
11	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
12	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
13	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
14	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
15	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
16	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
	Generation Additions in 2026-27 (MW)		5438	5254			
	Cumulative Addition up till 2027 (MW)		22,801	22,371			
			2027-28				

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	2,546	2,546	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			3,661	3,661			
Cumulative Addition up till 2028 (MW)			26,462	26,032			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
6	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
7	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
8	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
9	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
10	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
11	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			1,396	1,396			
Cumulative Addition up till 2029 (MW)			27,858	27,428			
2029-30							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
7	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
8	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29
9	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
10	New_Local Coal	Local Coal	1,320	1,214	Yet to be determined	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
15	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
16	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			3,178	3,072			
Cumulative Addition up till 2030 (MW)			31,035	30,499			
2030-31							
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
Generation Additions in 2030-31 (MW)			3,549	3,549			
Cumulative Addition up till 2031 (MW)			34,584	34,048			

G-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
			%								
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	6.53	6.53	6.43	6.25	6.33	5.95	0.98
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.51	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86

43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.28	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.78	55.82
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.79	54.79	54.79
80	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
81	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
82	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09
83	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
84	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
85	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
86	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
87	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94
88	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86

89	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
90	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.34
91	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.90	51.90
92	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	52.77	52.77
93	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
94	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
95	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
96	Gorkin Matiltan	HPP Committed	0.00	0.00	42.83	42.83	42.83	42.71	42.83	42.83	42.83
97	Jagran-II	HPP Committed	50.53	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
98	Karot	HPP Committed	44.39	44.29	44.39	44.39	44.39	44.29	44.39	44.39	44.39
99	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
100	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
101	Koto	HPP Committed	57.19	57.08	57.24	57.24	57.24	57.00	57.19	57.21	57.24
102	Lawi	HPP Committed	0.00	48.08	48.10	48.10	48.10	47.93	48.05	48.08	48.10
103	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
104	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	42.71	42.60	42.71	42.71	42.71
105	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
106	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
107	Chamfall	HPP Committed	0.00	49.12	49.12	49.12	49.12	48.99	49.12	49.12	49.12
108	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.66	73.66	73.60	73.66	73.66	73.66
109	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
110	Deg Outfall	HPP Committed	76.26	76.09	76.29	76.29	76.29	76.09	76.29	76.29	76.29
111	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
112	Karora	HPP Committed	67.46	67.57	67.62	67.62	67.62	67.46	67.55	67.58	67.62
113	Kathai-II	HPP Committed	0.00	0.00	60.37	60.37	60.37	60.21	60.37	60.37	60.37
114	Kurram Tangi	HPP Committed	0.00	17.01	17.05	17.05	17.05	17.01	17.05	17.05	17.05
115	Riali-II	HPP Committed	0.00	51.16	53.17	53.17	53.17	53.01	53.16	53.16	53.17
116	Allai Khwar	HPP Existing	44.25	44.20	44.32	44.32	44.32	44.20	44.32	44.32	44.32
117	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
118	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
119	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
120	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
121	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
122	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
123	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95
124	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
125	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
126	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
127	Mangla	HPP Existing	64.98	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
128	Neelum Jehlum	HPP Existing	51.65	51.54	51.69	51.69	51.69	51.54	51.69	51.69	51.69
129	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
130	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
131	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
132	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
133	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
134	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64

135	Engro 90MW	CCGT_Gas	90.23	74.96	62.46	50.72	45.70	35.35	33.22	27.12	23.17
136	Foundation	CCGT_Gas	89.97	90.25	90.00	89.98	82.82	57.94	81.13	57.94	57.94
137	Guddu-I	CCGT_Gas	36.90	74.63	74.43	74.42	68.53	17.10	67.32	16.88	15.57
138	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
139	Guddu-V (747)	CCGT_Gas	75.56	75.77	75.56	75.56	69.84	65.25	72.87	39.93	20.36
140	Liberty	CCGT_Gas	74.86	75.02	46.06	73.47	0.00	0.00	0.00	0.00	0.00
141	Uch	CCGT_Gas	86.08	86.32	86.08	86.08	48.34	42.90	44.02	43.09	0.00
142	Uch-II	CCGT_Gas	87.77	88.05	87.81	87.78	57.97	51.33	51.33	51.32	51.32
143	SNPC-I	KE_CCGT_Gas	91.98	92.25	91.96	91.99	84.40	33.91	75.89	32.26	32.29
144	SNPC-II	KE_CCGT_Gas	91.98	92.25	91.96	91.99	84.51	35.61	82.84	32.98	34.62
145	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
146	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
147	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
156	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
158	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
159	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
160	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
164	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
165	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
166	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
167	K-2	Nuclear	85.06	85.30	85.07	85.07	85.07	85.29	85.06	85.06	85.07
168	K-3	Nuclear	85.66	85.90	85.67	85.67	85.67	85.89	85.66	85.66	85.67
169	Engro Thar	Local Coal	82.51	82.74	82.51	82.51	82.51	81.59	81.54	81.03	77.58
170	Gwadar	Local Coal	0.00	0.00	0.00	69.18	82.33	81.88	82.20	73.81	70.04
171	Lucky	Local Coal	85.08	85.31	85.08	85.08	85.08	85.31	85.07	85.08	85.08
172	NEW_L.Coal 660	Local Coal	0.00	0.00	0.00	0.00	83.34	83.56	83.33	83.34	83.34
173	Thal Nova	Local Coal	49.35	85.21	84.98	84.98	84.98	84.57	84.67	84.11	82.19
174	Thar TEL	Local Coal	84.98	85.21	84.98	84.98	84.98	84.20	84.46	83.83	82.10
175	Thar-I (SSRL)	Local Coal	42.14	85.21	84.98	84.98	84.98	85.09	84.98	84.75	84.72
176	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	83.34	83.55	83.33	83.33	83.33
177	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
178	Jamshoro Coal	Imported Coal	49.36	84.04	83.89	84.21	23.58	12.27	19.54	13.68	10.29
179	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
180	Sahiwal Coal	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00

181	FPCL	KE_Imported Coal	82.15	77.13	18.09	22.28	9.13	6.73	9.99	6.43	9.43
182	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
183	Balloki	CCGT_RLNG	4.19	2.02	0.96	2.21	0.53	0.29	0.54	0.32	0.32
184	Bhikki	CCGT_RLNG	1.20	0.78	0.00	0.58	0.20	0.05	0.29	0.20	0.22
185	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
186	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
187	Haveli	CCGT_RLNG	10.92	5.77	3.29	5.35	1.94	0.77	1.80	1.00	0.83
188	KAPCO 1	CCGT_RLNG	35.31	35.38	35.25	0.00	0.00	0.00	0.00	0.00	0.00
189	KAPCO 2	CCGT_RLNG	11.86	11.83	11.89	0.00	0.00	0.00	0.00	0.00	0.00
190	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
191	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.00	0.00
192	Orient	CCGT_RLNG	37.73	23.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Rousch	CCGT_RLNG	0.24	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00
194	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
195	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.00	0.00
196	Trimmu	CCGT_RLNG	26.05	20.80	12.24	12.79	5.68	2.21	3.73	2.17	1.81
197	BQPS2	KE_CCGT_RLNG	85.21	83.46	29.63	61.62	10.67	5.81	9.34	5.68	7.53
198	BQPS3	KE_CCGT_RLNG	89.81	89.80	79.57	83.92	22.40	14.57	20.07	15.22	17.15
199	KCCPP	KE_CCGT_RLNG	85.10	82.46	22.09	19.91	9.40	4.33	7.22	4.64	4.19
200	KTGTPS	KE_CCGT_RLNG	45.16	40.73	8.23	10.12	3.86	2.59	3.41	2.47	2.69
201	SGTPS	KE_CCGT_RLNG	48.00	44.44	9.14	11.02	4.30	2.85	3.48	2.81	3.02
202	BQPS1-U1	KE_ST_RLNG	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
203	BQPS1-U5	KE_ST_RLNG	29.34	30.27	1.66	1.71	0.16	0.46	0.79	0.75	1.10
204	BQPS1-U6	KE_ST_RLNG	16.15	15.84	1.43	1.54	0.00	0.01	0.33	0.46	0.67
205	BQPS1-U2	KE_GT_RLNG	22.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

G-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
2022	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	1,252	-	-	-	1,174	44,372
2025	-	2,365	-	-	-	4,972	-	-	1,000	8,337	52,708
2026	300	653	-1,300	-	-	1,820	-	-	-	1,473	54,182
2027	2,310	2,558	-	-	-	570	-225	-1,292	-	3,921	58,103
2028	-	545	-	-	-	3,116	-	-131	-	3,530	61,633
2029	-	826	-	-	-	570	-	-727	-	669	62,301
2030	1,320	1,288	-172	-	-	570	-	-136	-	2,870	65,171
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	67,684
Total	**7,230**	**22,403**	**8,710**	**3,620**	**4,680**	**16,761**	**1,933**	**1,347**	**1,000**	**26,423**	**67,684**

G-7. IGCEP Generation Mix 2023-2031 (GWh)

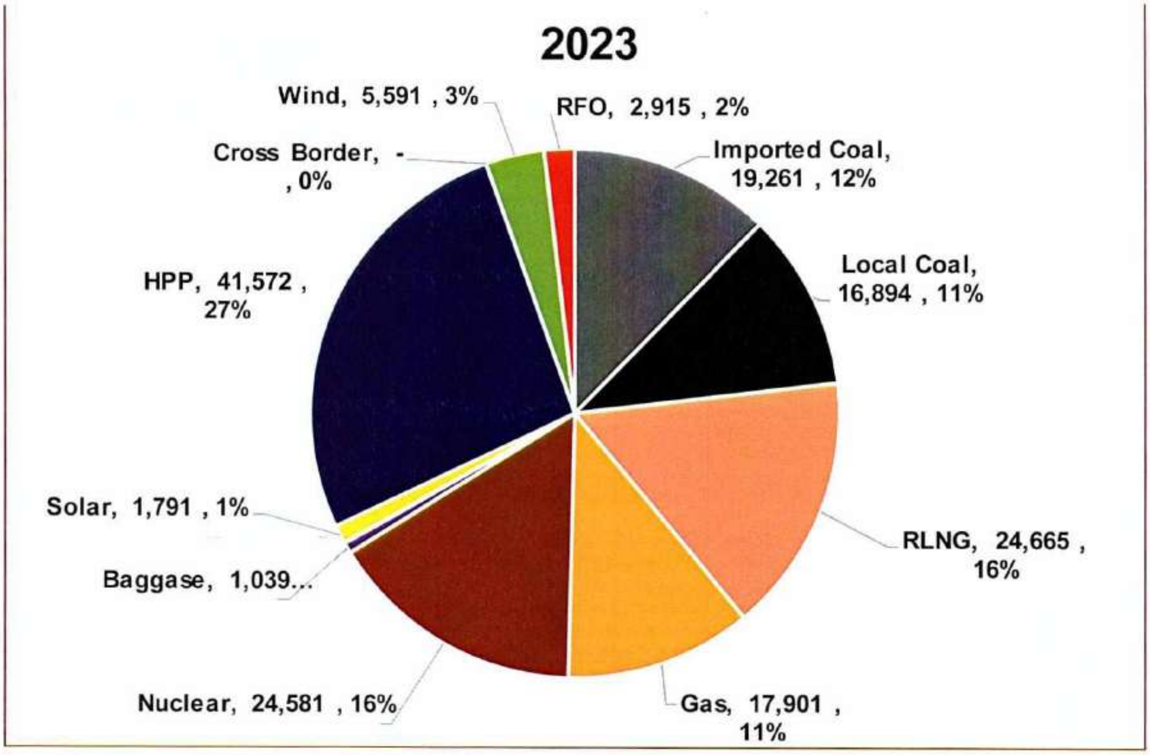

Chart G-1: IGCEP Generation Mix 2023 (GWh)

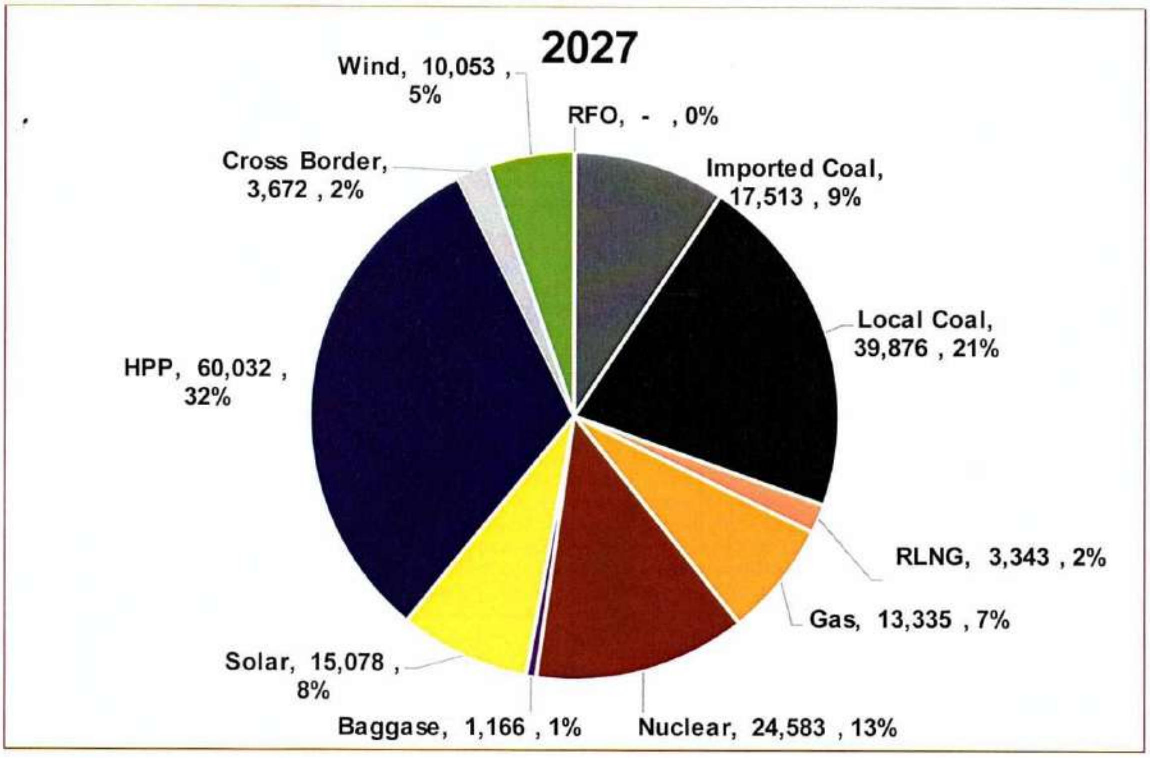

Chart G-2: IGCEP Generation Mix 2027 (GWh)

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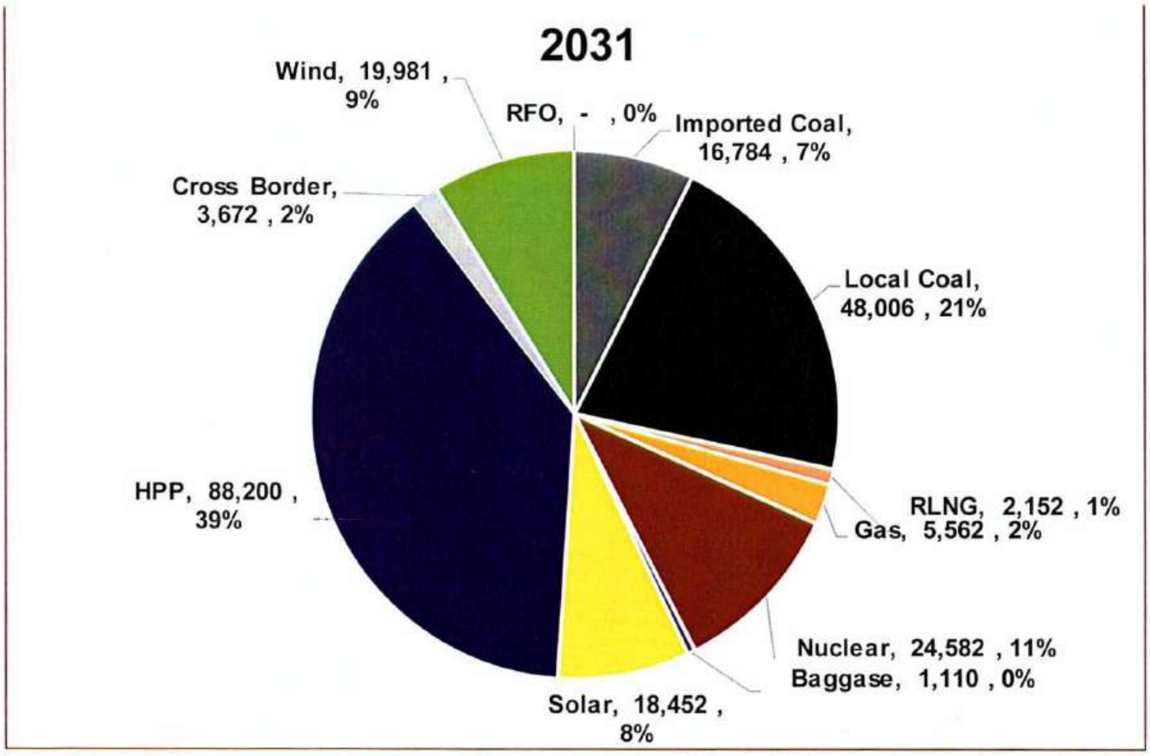


Chart G-3: IGCEP Generation Mix 2031 (GWh)

G-8. IGCEP Generation Mix 2023-31 (MW)

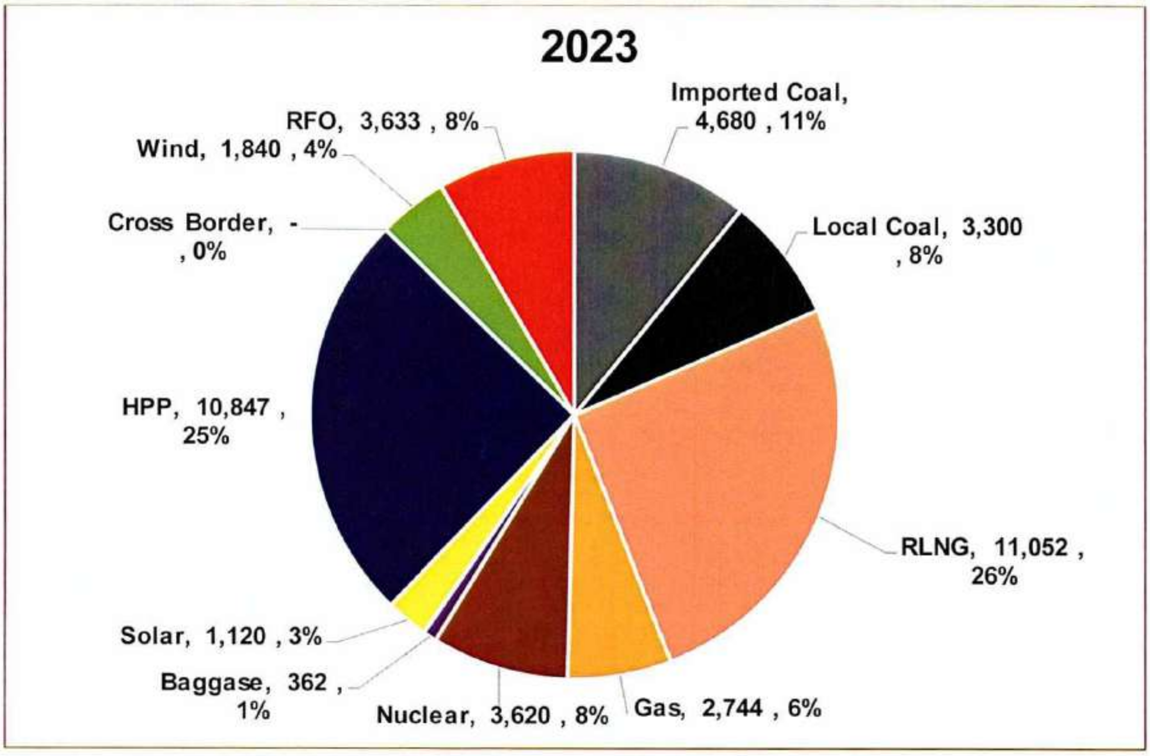


Chart G-4: IGCEP Generation Mix 2023 (MW)

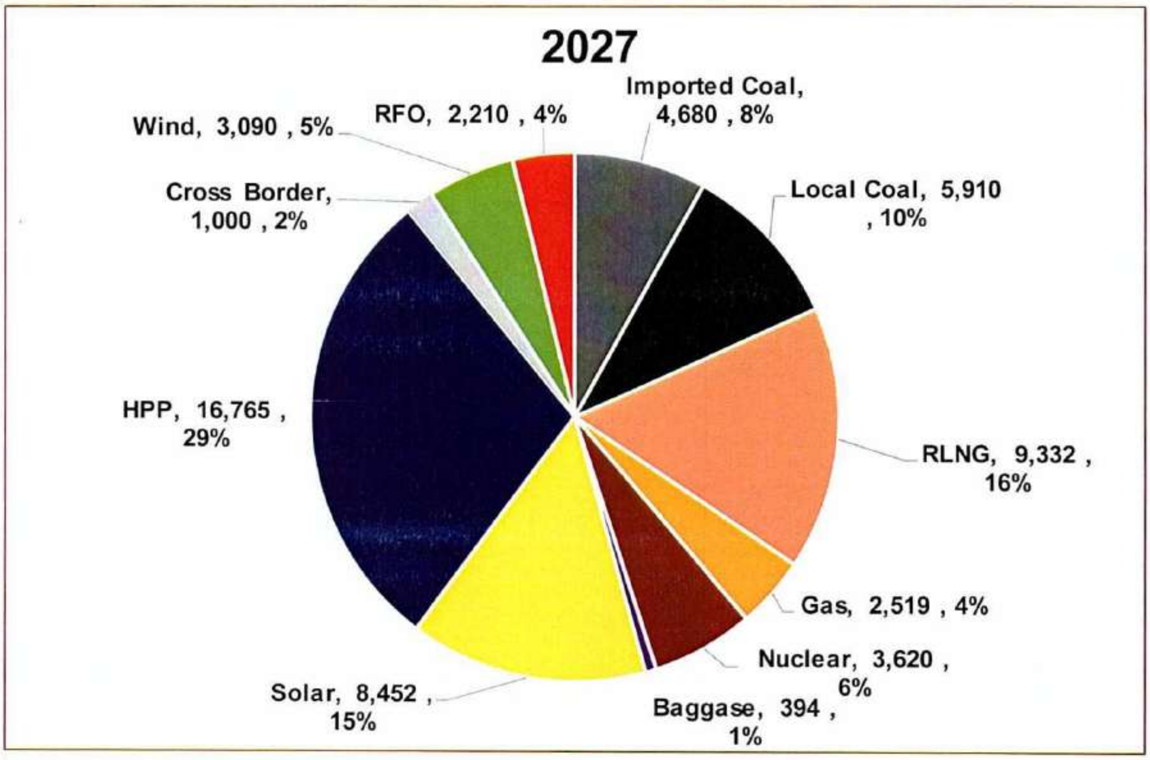


Chart G-5: IGCEP Generation Mix 2027 (MW)

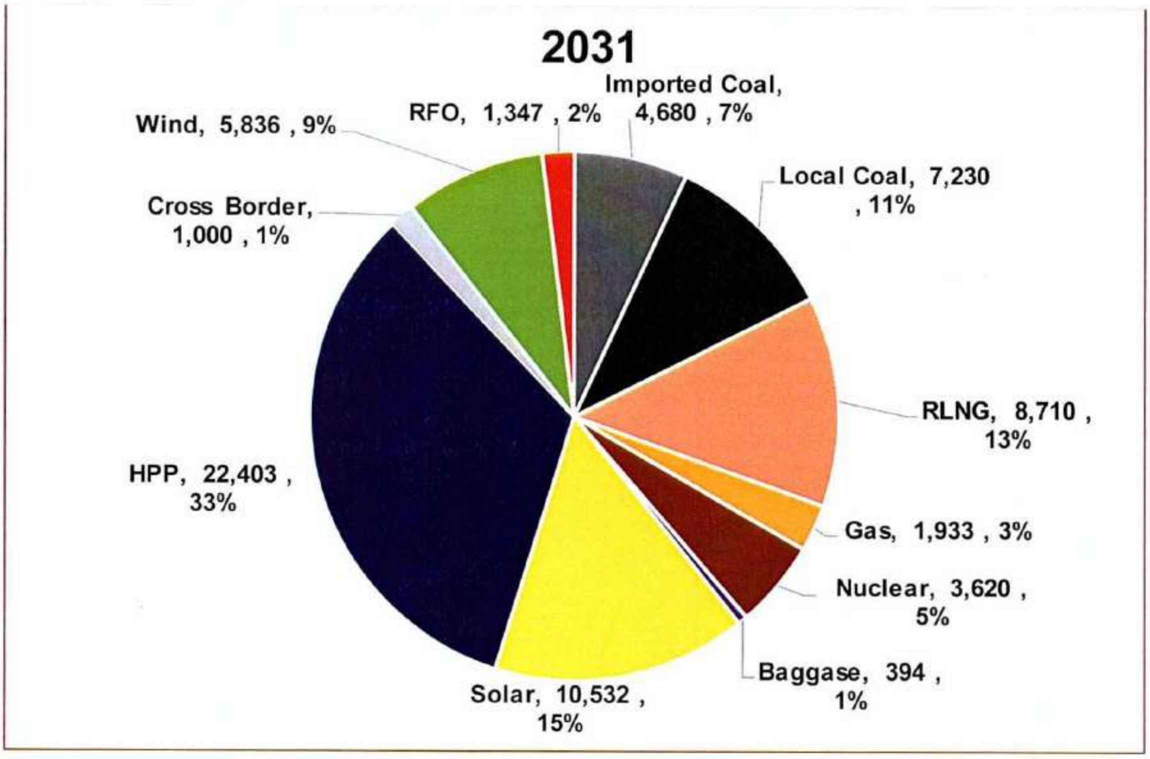
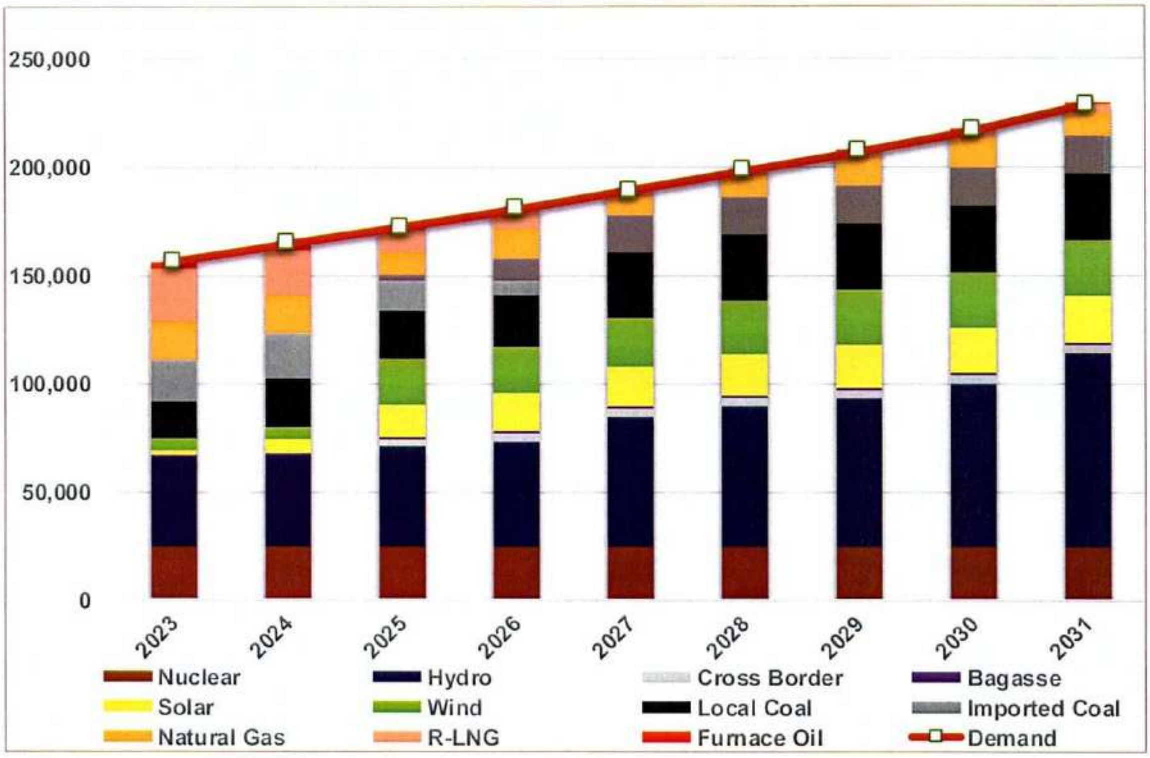


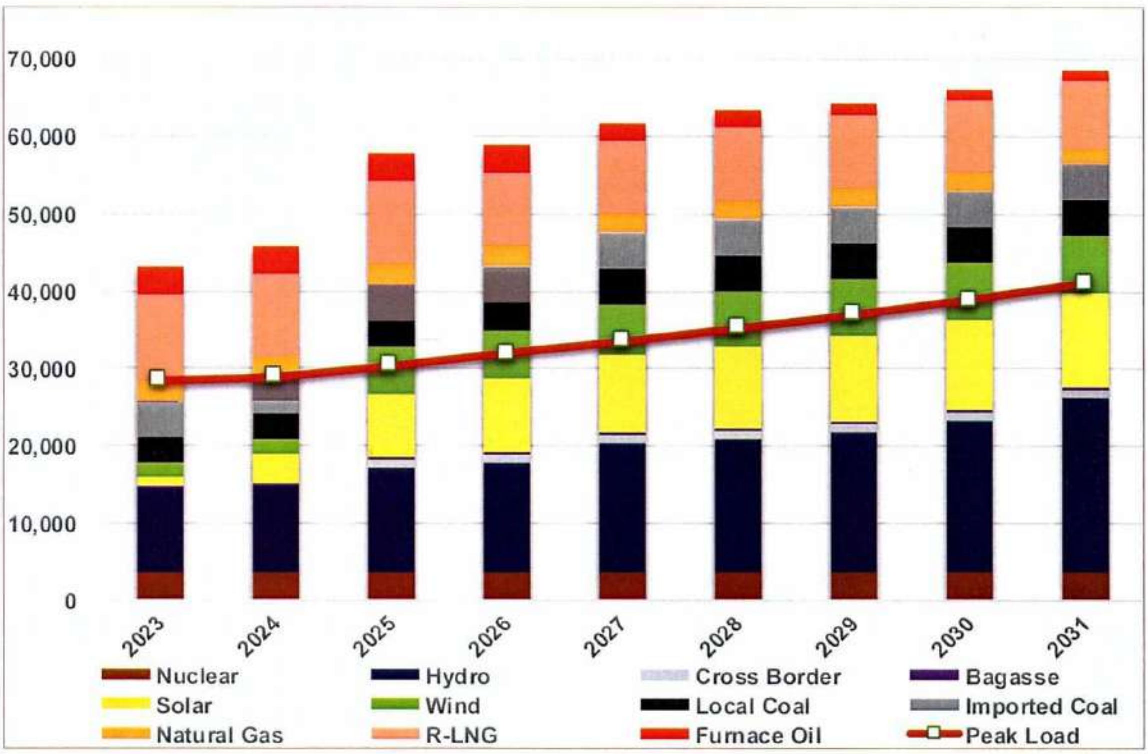
Chart G-6: IGCEP Generation Mix 2031 (MW)

Annexure H. Unconstrained VRE

H-1. Annual Energy Generation Vs Annual Energy Demand (GWh) - Country



H-2. Installed Capacity Vs Peak Demand (MW) - Country



H-3. Optimized Generation Capacity Additions (MW)

Fiscal Year	Coal Fired Steam Local Coal	Coal Fired Steam Local Coal KE	HPP	HPP KE	Solar Utility MW_p	Solar Feeder MW_p	Solar KE MW_p	Wind NTDC	Wind KE	Bagasse	Per Year Capacity Addition	Cumulative Capacity Addition
2024	-	-	-	-	-	2,000	-	-	-	-	2,000	2,000
2025	-	-	10	-	3,818	-	150	4,244	50	-	8,272	10,272
2026	-	-	13	-	885	-	150	-	50	-	1,098	11,369
2027	-	990	-	-	-	-	150	236	50	-	1,426	12,795
2028	-	-	-	-	-	-	150	613	50	-	813	13,608
2029	-	-	360	-	-	-	150	125	50	-	685	14,294
2030	-	-	993	82	-	-	150	-	50	-	1,275	15,569
2031	-	-	2,130	-	-	-	150	-	50	-	2,330	17,899
Total	**-**	**990**	**3,506**	**82**	**4,703**	**2,000**	**1,050**	**5,218**	**350**	**-**	**17,899**	

H-4. List of Projects uptill 2031 (Committed + Optimized)

#	Name of Project	Fuel Type	Installed Capacity	Dependable Capacity	Agency	Status	Schedule of Commissioning
			2021-22				
1	Chianwali	Hydro	5	5	PPMU	PC-1 Approved	Mar-22
2	Jabori	Hydro	10	10	GoKPK	PC-1 Approved	Mar-22
3	Deg Outfall	Hydro	4	4	PPMU	PC-1 Approved	Jun-22
Generation Additions in 2021-22 (MW)			20	20			
Cumulative Addition up till 2021-22 (MW)			20	20			
			2022-23				
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-22
2	Thar TEL	Local Coal	330	300	PPIB	LOS (Issued)	Jul-22
3	Trimmu	CCGT_RLNG	1,263	1,243	PPIB	LOS (Issued)	Jul-22
4	Karora	Hydro	11.8	11.8	GoKPK	PC-1 Approved	Aug-22
5	Mangla (U #5-6)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-22
6	Koto	Hydro	40.8	40.8	GoKPK	PC-1 Approved	Sep-22
7	Jamshoro Coal (U #1)	Imported Coal	660	627	GENCO	PC-1 Approved	Dec-22
8	Thal Nova	Local Coal	330	300	PPIB	LOS (Issued)	Dec-22
9	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	LOS (Issued)	Dec-22
10	Helios	Solar	50	50	AEDB	Category-II Project	Apr-23
11	HNDS	Solar	50	50	AEDB	Category-II Project	Apr-23
12	Jagran-II (U #1)	Hydro	12	12	AJK-HEB	PC-1 Approved	Apr-23
13	Meridian	Solar	50	50	AEDB	Category-II Project	Apr-23
14	Mangla (U #3-4)	Hydro	70	70	WAPDA	Mangla Refurbishment	May-23
15	Jagran-II (U #2)	Hydro	12	12	AJK-HEB	PC-1 Approved	May-23
Generation Additions in 2022-23 (MW)			4,640	4,421			
Cumulative Addition up till 2023 (MW)			4,659	4,440			

2023-24							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-23
2	Jagran-II (U #3-4)	Hydro	24	24	AJK-HEB	PC-1 Approved	Jul-23
3	New_Solar_DG	Solar	2,000	2,000	Yet to be determined	Optimized	Jul-23
4	Chamfall	Hydro	3.22	3.22	AJK-HEB	PC-1 Approved	Aug-23
5	Access_Electric	Solar	10	10	AEDB	Category-I Project	Sep-23
6	Access_Solar	Solar	12	11.52	AEDB	Category-I Project	Sep-23
7	Manjhand	Solar	50	50	GoS	PC-1 Approved	Sep-23
8	Siachen	Solar	100	100	GoS	Category-II Project	Sep-23
9	Kurram Tangi	Hydro	18	18	WAPDA	PC-1 Approved	Oct-23
10	Riali-II	Hydro	7.08	7.08	PPIB	LOS (Issued)	Dec-23
11	Zorlu	Solar	100	100	PPDB	Category-II Project	Dec-23
12	Lawi	Hydro	69	69	GoKPK	PC-1 Approved	Apr-24
13	Suki Kinari (U #1)	Hydro	221	221	PPIB	LOS (Issued)	May-24
14	Safe	Solar	10	10	AEDB	Category-I Project	Jun-24
15	Trans_Atlantic	Wind	50	50	AEDB	Category-II Project	Jun-24
16	Western	Wind	50	50	AEDB	Category-II Project	Jun-24
Generation Additions in 2023-24 (MW)			3,094	3,094			
Cumulative Addition up till 2024 (MW)			7,753	7,534			
2024-25							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-24
2	Daral Khwar-II	Hydro	10	10	PEDO	Optimized	Jul-24
3	Gorkin Matiltan	Hydro	84	84	GoKPK	PC-1 Approved	Jul-24
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-24
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-24
6	Mangla (U #1-2)	Hydro	70	70	WAPDA	Mangla Refurbishment	Jul-24
7	New_Solar_Utility	Solar	3,818	3,818	Yet to be determined	Optimized	Jul-24

8	New_Wind	Wind	4,244	4,244	Yet to be determined	Optimized	Jul-24
9	Tarbela Ext5 (U #1)	Hydro	510	510	WAPDA	PC-1 Approved	Jul-24
10	Suki Kinari (U #2)	Hydro	221	221	PPIB	LOS (Issued)	Jul-24
11	CASA	Cross Border Interconnection	1,000	1,000	NTDC	G2G	Aug-24
12	Tarbela Ext5 (U #2)	Hydro	510	510	WAPDA	PC-1 Approved	Aug-24
13	Shahtaj	Bagasse	32	32	AEDB	Category-I Project	Aug-24
14	Tarbela Ext5 (U #3)	Hydro	510	510	WAPDA	PC-1 Approved	Sep-24
15	Suki Kinari (U #3)	Hydro	221	221	PPIB	LOS (Issued)	Sep-24
16	Suki Kinari (U #4)	Hydro	221	221	PPIB	LOS (Issued)	Nov-24
17	Kathai-II	Hydro	8	8	PPIB	LOS (Issued)	Dec-24
Generation Additions in 2024-25 (MW)			12,029	12,029			
Cumulative Addition up till 2025 (MW)			19,782	19,563			
2025-26							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-25
2	Balkani	Hydro	8	8	PEDO	Optimized	Jul-25
3	Batdara	Hydro	5	5	AJK-HEB	Optimized	Jul-25
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-25
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-25
6	New_Solar_Utility	Solar	885	885	Yet to be determined	Optimized	Jul-25
7	Gwadar	Local Coal	300	273	PPIB	LOS (Issued)	Aug-25
8	Mangla (U #9-10)	Hydro	70	70	WAPDA	Mangla Refurbishment	Sep-25
9	Chapari Charkhel	Hydro	10.56	10.56	GoKPK	PC-1 Approved	Sep-25
10	Dasu (U #1)	Hydro	360	360	WAPDA	PC-1 Approved	May-26
11	Mohmand Dam (U #1)	Hydro	200	200	WAPDA	PC-1 Approved	May-26
Generation Additions in 2025-26 (MW)			2,408	2,381			
Cumulative Addition up till 2026 (MW)			22,190	21,944			
2026-27							

1	Net Meter	Solar	370	370	AEDB	Committed	Jul-26
2	Dasu (U #2)	Hydro	360	360	WAPDA	PC-1 Approved	Jul-26
3	KE_New_Local Coal	Local Coal	990	912	Yet to be determined	Optimized	Jul-26
4	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-26
5	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-26
6	New_Wind	Wind	236	236	Yet to be determined	Optimized	Jul-26
7	Mohmand Dam (U #2)	Hydro	200	200	WAPDA	PC-1 Approved	Jul-26
8	Dasu (U #3)	Hydro	360	360	WAPDA	PC-1 Approved	Aug-26
9	Mohmand Dam (U #3)	Hydro	200	200	WAPDA	PC-1 Approved	Sep-26
10	Dasu (U #4)	Hydro	360	360	WAPDA	PC-1 Approved	Nov-26
11	Mangla (U #7-8)	Hydro	30	30	WAPDA	Mangla Refurbishment	Nov-26
12	Mohmand Dam (U #4)	Hydro	200	200	WAPDA	PC-1 Approved	Nov-26
13	Dasu (U #5)	Hydro	360	360	WAPDA	PC-1 Approved	Feb-27
14	Keyal Khwar (U #1)	Hydro	64	64	WAPDA	PC-1 Approved	Feb-27
15	Dasu (U #6)	Hydro	360	360	WAPDA	PC-1 Approved	May-27
16	Keyal Khwar (U #2)	Hydro	64	64	WAPDA	PC-1 Approved	May-27
Generation Additions in 2026-27 (MW)			4354	4276			
Cumulative Addition up till 2027 (MW)			26,544	26,220			
2027-28							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-27
2	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-27
3	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-27
4	New_Wind	Wind	613	613	Yet to be determined	Optimized	Jul-27
5	Gabral Kalam	Hydro	88	88	GoKPK	PC-1 Approved	Nov-27
6	Madyan	Hydro	157	157	GoKPK	PC-1 Approved	Nov-27
7	Balakot	Hydro	300	300	GoKPK	PC-1 Approved	Dec-27
Generation Additions in 2027-28 (MW)			1,728	1,728			

Cumulative Addition up till 2028 (MW)			28,272	27,948			
2028-29							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-28
2	Bata Kundi	Hydro	99	99	GoKPK	Optimized	Jul-28
3	Chowkel Khwar	Hydro	60	60	PEDO	Optimized	Jul-28
4	CJ	Hydro	25	25	PPDB	Optimized	Jul-28
5	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-28
6	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-28
7	New_Wind	Wind	125	125	Yet to be determined	Optimized	Jul-28
8	Nila Da Katha	Hydro	31.3	31.3	PEDO	Optimized	Jul-28
9	Taobut	Hydro	10	10	AJK-HEB	Optimized	Jul-28
10	Taunsa	Hydro	135	135	PPDB	Optimized	Jul-28
11	Azad Pattan (U #1)	Hydro	175	175	PPIB	LOS (Issued)	Dec-28
12	Azad Pattan (U #2)	Hydro	175	175	PPIB	LOS (Issued)	Mar-29
13	Azad Pattan (U #3)	Hydro	175	175	PPIB	LOS (Issued)	Jun-29
Generation Additions in 2028-29 (MW)			1,581	1,581			
Cumulative Addition up till 2029 (MW)			29,853	29,529			
2029-30							
1	Net Meter	Solar	370	370	AEDB	Committed	Jul-29
2	Arkari Gol	Hydro	99	99	PEDO	Optimized	Jul-29
3	Asrit Kedam	Hydro	215	215	PEDO	Optimized	Jul-29
4	Dowarian	Hydro	40	40	AJK-HEB	Optimized	Jul-29
5	Jagran-IV	Hydro	22	22	AJK-HEB	Optimized	Jul-29
6	Janawai	Hydro	12	12	AJK-HEB	Optimized	Jul-29
7	Kalam Asrit	Hydro	238	238	PEDO	Optimized	Jul-29
8	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-29
9	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-29

10	Nagdar	Hydro	35	35	AJK-HEB	Optimized	Jul-29
11	Rajdhani	Hydro	132	132	PPIB	Optimized	Jul-29
12	Sharmai	Hydro	152.12	152.12	PEDO	Optimized	Jul-29
13	Shounter	Hydro	48	48	AJK-HEB	Optimized	Jul-29
14	Turtonas Uzghor	Hydro	82.25	82.25	KE	Optimized	Jul-29
15	Azad Pattan (U #4)	Hydro	175	175	PPIB	LOS (Issued)	Sep-29
16	Kohala (U #1)	Hydro	275	275	PPIB	LOS (Issued)	Jun-30
Generation Additions in 2029-30 (MW)			2,096	2,096			
Cumulative Addition up till 2030 (MW)			31,948	31,624			
2030-31							
1	Mahl	Hydro	640	640	PPIB	Optimized	Jul-30
2	Thakot-III	Hydro	1,490	1,490	WAPDA	Optimized	Jul-30
3	KE_New_Solar	Solar	150	150	Yet to be determined	Optimized	Jul-30
4	KE_New_Wind	Wind	50	50	Yet to be determined	Optimized	Jul-30
5	Net Meter	Solar	370	370	AEDB	Committed	Jul-30
6	Kohala (U #2)	Hydro	275	275	PPIB	LOS (Issued)	Aug-30
7	Kohala (U #3)	Hydro	275	275	PPIB	LOS (Issued)	Oct-30
8	Kohala (U #4)	Hydro	275	275	PPIB	LOS (Issued)	Dec-30
9	Kohala (U #5)	Hydro	12	12	PPIB	LOS (Issued)	Feb-31
10	Kohala (U #6)	Hydro	12	12	PPIB	LOS (Issued)	Mar-31
Generation Additions in 2030-31 (MW)			3,549	3,549			
Cumulative Addition up till 2031 (MW)			35,497	35,173			

H-5. Annual Capacity Factors (%age)

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
1	Almoiz	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
2	Chanar	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
3	Chiniot	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
4	Fatima	Bagasse	6.53	6.55	1.03	6.23	0.78	6.21	6.23	5.95	5.90
5	Hamza	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
6	JDW-II	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
7	JDW-III	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
8	Ryk_Mills	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
9	Shahtaj	Bagasse	0.00	0.00	45.62	45.62	45.62	45.77	45.62	45.62	45.62
10	Thal_Layyah	Bagasse	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62	45.62
11	Access_Electric	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
12	Access_Solar	PV	0.00	20.08	20.17	20.17	20.17	20.11	20.17	20.17	20.17
13	Appolo	PV	18.96	18.91	18.96	18.96	18.96	18.91	18.96	18.96	18.96
14	Best	PV	18.94	18.89	18.94	18.94	18.94	18.89	18.94	18.94	18.94
15	Crest	PV	19.19	19.13	19.19	19.19	19.19	19.13	19.19	19.19	19.19
16	Helios	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
17	HNDS	PV	23.33	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
18	Manjhand	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
19	Meridian	PV	23.27	23.27	23.33	23.33	23.33	23.27	23.33	23.33	23.33
20	Net_Meter	PV	17.08	17.03	17.08	17.08	17.08	17.03	17.08	17.08	17.08
21	New_Solar	PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
22	New_Solar_Feeder	PV	0.00	19.95	20.00	20.00	20.00	19.95	20.00	20.00	20.00
23	QA_Solar	PV	19.04	18.99	19.04	19.04	19.04	18.99	19.04	19.04	19.04
24	Safe	PV	0.00	20.17	20.17	20.17	20.17	20.11	20.17	20.17	20.17
25	Siachen	PV	0.00	23.23	23.33	23.33	23.33	23.27	23.33	23.33	23.33
26	Zhenfa	PV	21.50	21.44	21.50	21.50	21.50	21.44	21.50	21.50	21.50
27	Zorlu	PV	0.00	20.11	20.17	20.17	20.17	20.11	20.17	20.17	20.17
28	Gharo	KE_PV	25.25	25.18	25.25	25.25	25.25	25.18	25.25	25.25	25.25
29	KE_New_Solar	KE_PV	0.00	0.00	22.08	22.08	22.08	22.02	22.08	22.08	22.08
30	Oursun	KE_PV	20.97	20.91	20.97	20.97	20.97	20.91	20.97	20.97	20.97
31	Act	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
32	Act_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
33	Artistic_wind	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
34	Artistic_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
35	Dawood	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
36	Din	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
37	FFC	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
38	FWEL-I	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
39	FWEL-II	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
40	Gul Ahmed	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
41	Gul_Electric	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
42	Hawa	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
43	Indus_Energy	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
44	Jhimpir	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
45	Lakeside	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
46	Liberty_Wind_1	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
47	Liberty_Wind_2	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
48	Master	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
49	Master_Green	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
50	Metro_Power	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
51	Metro_Wind	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
52	NASDA	Wind	38.93	38.07	38.17	38.17	38.17	38.07	38.17	38.17	38.17
53	New_Wind	Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
54	Sachal	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
55	Sapphire_Wind	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
56	Tenaga	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
57	Three_Gorges_I	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
58	Three_Gorges_II	Wind	34.86	34.82	34.86	34.66	34.86	34.82	34.86	34.86	34.86
59	Three_Gorges_III	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
60	Trans_Atlantic	Wind	0.00	41.17	41.28	41.28	41.28	41.17	41.28	41.28	41.28
61	Tricom	Wind	37.94	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
62	Tricon_A	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
63	Tricon_B	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
64	Tricon_C	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
65	UEP	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
66	Western	Wind	0.00	37.09	37.19	37.19	37.19	37.09	37.19	37.19	37.19
67	Yunus	Wind	30.99	30.91	30.99	30.99	30.99	30.91	30.99	30.99	30.99
68	Zephyr	Wind	34.86	34.82	34.86	34.86	34.86	34.82	34.86	34.86	34.86
69	Zorlu_Wind	Wind	31.99	31.91	31.99	31.99	31.99	31.91	31.99	31.99	31.99
70	KE_New_Wind	KE_Wind	0.00	0.00	41.28	41.28	41.28	41.17	41.28	41.28	41.28
71	CASA	Interconnection	0.00	0.00	41.92	41.92	41.92	41.80	41.92	41.92	41.92
72	Balkani	HPP Candidate	0.00	0.00	0.00	51.55	51.55	51.41	51.55	51.55	51.55
73	Batdara	HPP Candidate	0.00	0.00	0.00	49.49	49.49	49.35	49.49	49.49	49.49
74	Daral Khwar-II	HPP Candidate	0.00	0.00	52.05	52.05	52.05	51.91	52.05	52.05	52.05
75	Janawai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.72	55.82
76	Taobut	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	46.69	46.69	46.69
77	Arkari Gol	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.22	42.22
78	Asrit Kedam	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.72	49.72
79	Bata Kundi	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	54.76	54.79	54.79
80	Chowkel Khwar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	44.57	44.57	44.57
81	CJ	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	50.50	50.50	50.50
82	Dowarian	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.85	48.85
83	Jagran-IV	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.09	49.09

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
84	Kalam Asrit	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.41	44.41
85	Mahl	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.53
86	Nagdar	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.87	48.87
87	Nila Da Katha	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	51.31	51.31	51.31
88	Rajdhani	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.46	58.46
89	Sharmai	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.94	50.94
90	Shounter	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.86	48.86
91	Taunsa	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	55.02	55.02	55.02
92	Thakot-III	HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.31
93	Turtonas Uzghor	KE_HPP Candidate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.89	51.90
94	Azad Pattan	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	52.77	52.77	52.77
95	Balakot	HPP Committed	0.00	0.00	0.00	0.00	0.00	41.21	41.21	41.21	41.21
96	Dasu	HPP Committed	0.00	0.00	0.00	64.47	64.47	64.29	64.47	64.47	64.47
97	Gabral Kalam	HPP Committed	0.00	0.00	0.00	0.00	0.00	33.77	33.77	33.77	33.77
98	Gorkin Matiltan	HPP Committed	0.00	0.00	42.71	42.80	42.83	42.71	42.83	42.83	42.83
99	Jagran-II	HPP Committed	50.39	50.39	50.53	50.53	50.53	50.39	50.53	50.53	50.53
100	Karot	HPP Committed	44.38	44.29	44.38	44.37	44.38	44.29	44.38	44.39	44.39
101	Keyal Khwar	HPP Committed	0.00	0.00	0.00	0.00	52.07	51.92	52.07	52.07	52.07
102	Kohala	HPP Committed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.14	56.14
103	Koto	HPP Committed	57.12	57.08	56.98	56.98	57.12	56.96	57.12	57.15	57.23
104	Lawi	HPP Committed	0.00	47.99	47.88	47.84	47.99	47.90	47.99	48.02	48.10
105	Madyan	HPP Committed	0.00	0.00	0.00	0.00	0.00	47.43	47.43	47.43	47.43
106	Mohmand Dam	HPP Committed	0.00	0.00	0.00	42.71	42.71	42.60	42.71	42.71	42.71
107	Suki Kinari	HPP Committed	0.00	49.07	49.07	49.07	49.07	48.93	49.07	49.07	49.07
108	Tarbela_Ext_5	HPP Committed	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05	10.05
109	Chamfall	HPP Committed	0.00	48.99	49.12	49.12	49.12	48.99	49.12	49.12	49.12
110	Chapari Charkhel	HPP Committed	0.00	0.00	0.00	73.57	73.62	73.57	73.62	73.66	73.66
111	Chianwali	HPP Committed	61.15	60.98	61.15	61.15	61.15	60.98	61.15	61.15	61.15
112	Deg Outfall	HPP Committed	76.29	76.09	76.29	76.26	76.29	76.09	76.29	76.29	76.29
113	Jabori	HPP Committed	77.21	77.23	77.21	77.21	77.21	77.23	77.21	77.21	77.21
114	Karora	HPP Committed	67.42	67.57	67.33	67.30	67.48	67.42	67.48	67.51	67.62
115	Kathai-II	HPP Committed	0.00	0.00	60.37	60.37	60.37	60.21	60.37	60.37	60.37
116	Kurram Tangi	HPP Committed	0.00	17.01	17.05	17.05	17.05	17.01	17.05	17.05	17.05
117	Riali-II	HPP Committed	0.00	53.01	53.14	53.14	53.15	53.01	53.15	53.15	53.17
118	Allai Khwar	HPP Existing	44.32	44.20	44.32	44.28	44.32	44.20	44.32	44.32	44.32
119	Chashma	HPP Existing	48.58	48.45	48.58	48.58	48.58	48.45	48.58	48.58	48.58
120	Daral Khwar	HPP Existing	38.58	38.48	38.58	38.58	38.58	38.48	38.58	38.58	38.58
121	Dubair Khwar	HPP Existing	53.09	52.95	53.09	53.09	53.09	52.95	53.09	53.09	53.09
122	Ghazi Brotha	HPP Existing	52.78	52.63	52.78	52.78	52.78	52.63	52.78	52.78	52.78
123	Golen Gol	HPP Existing	9.15	9.12	9.15	9.15	9.15	9.12	9.15	9.15	9.15
124	Gulpur	HPP Existing	28.92	28.84	28.92	28.92	28.92	28.84	28.92	28.92	28.92
125	Jagran-I	HPP Existing	48.95	48.82	48.95	48.95	48.95	48.82	48.95	48.95	48.95

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
126	Jinnah	HPP Existing	25.74	25.67	25.74	25.74	25.74	25.67	25.74	25.74	25.74
127	Khan Khwar	HPP Existing	40.22	40.11	40.22	40.22	40.22	40.11	40.22	40.22	40.22
128	Malakand-III	HPP Existing	53.86	53.71	53.86	53.86	53.86	53.71	53.86	53.86	53.86
129	Mangla	HPP Existing	64.94	60.97	58.32	56.00	54.77	54.20	54.35	54.35	54.35
130	Neelum Jehlum	HPP Existing	51.69	51.54	51.69	51.65	51.69	51.54	51.69	51.69	51.69
131	New Bong	HPP Existing	55.49	55.34	55.49	55.49	55.49	55.34	55.49	55.49	55.49
132	Patrind	HPP Existing	43.76	43.64	43.76	43.76	43.76	43.64	43.76	43.76	43.76
133	Small Hydel	HPP Existing	45.20	45.08	45.20	45.20	45.20	45.08	45.20	45.20	45.20
134	Tarbela 1-14	HPP Existing	37.99	37.89	37.99	37.99	37.99	37.89	37.99	37.99	37.99
135	Tarbela_Ext_4	HPP Existing	30.12	30.04	30.12	30.12	30.12	30.04	30.12	30.12	30.12
136	Warsak	HPP Existing	50.64	50.50	50.64	50.64	50.64	50.50	50.64	50.64	50.64
137	Engro 90MW	CCGT_Gas	90.23	74.96	33.64	29.75	40.56	35.75	32.09	30.75	26.31
138	Foundation	CCGT_Gas	89.97	90.25	57.94	87.16	57.94	57.94	58.46	81.13	57.94
139	Guddu-I	CCGT_Gas	36.90	74.63	13.54	72.91	17.26	16.61	67.52	68.54	65.13
140	Guddu-II	CCGT_Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
141	Guddu-V (747)	CCGT_Gas	75.56	75.77	61.26	73.99	43.78	63.52	72.81	70.44	69.78
142	Liberty	CCGT_Gas	74.86	75.02	40.17	40.17	0.00	0.00	0.00	0.00	0.00
143	Uch	CCGT_Gas	86.08	86.32	39.97	42.89	43.07	43.50	45.30	48.14	0.00
144	Uch-II	CCGT_Gas	87.77	88.05	51.29	52.87	51.32	51.33	51.33	63.39	51.32
145	SNPC-I	KE_CCGT_Gas	91.98	92.25	66.45	88.52	35.30	34.13	40.31	83.97	39.99
146	SNPC-II	KE_CCGT_Gas	91.98	92.25	68.62	89.43	36.73	35.61	41.18	83.97	41.39
147	AES Lalpir	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	AES Pakgen	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	HUBCO	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Jamshoro-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Jamshoro-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Muzaffargarh-I U1	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Muzaffargarh-I U2	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Muzaffargarh-I U3	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	Muzaffargarh-II U4	ST_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156	Saba	ST_RFO	14.38	21.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	AGL	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
158	Atlas	DG_RFO	14.40	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
159	Engro 127MW	DG_RFO	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
160	HuB N	DG_RFO	36.12	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00
161	Kohinoor	DG_RFO	14.39	21.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Liberty Tech	DG_RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	Nishat C	DG_RFO	36.12	21.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00
164	Nishat P	DG_RFO	36.81	22.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
165	C-1	Nuclear	80.43	80.65	80.43	80.43	80.43	80.65	80.43	80.43	80.43
166	C-2	Nuclear	79.61	79.83	79.61	79.61	79.61	79.83	79.61	79.61	79.61
167	C-3	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01

#	Plant Name	Fuel	23	24	25	26	27	28	29	30	31
							%				
168	C-4	Nuclear	81.01	81.23	81.01	81.01	81.01	81.23	81.01	81.01	81.01
169	K-2	Nuclear	85.06	85.30	85.03	85.02	85.05	85.29	85.05	85.05	85.05
170	K-3	Nuclear	85.66	85.90	85.64	85.62	85.65	85.89	85.65	85.65	85.65
171	Engro Thar	Local Coal	82.51	82.74	81.47	81.53	80.12	80.83	80.96	81.04	77.77
172	Gwadar	Local Coal	0.00	0.00	0.00	67.98	76.50	80.97	81.38	79.92	78.10
173	Lucky	Local Coal	85.08	85.31	85.06	85.06	84.89	84.98	84.96	85.07	85.07
174	Thal Nova	Local Coal	49.35	85.21	84.06	84.07	83.31	83.73	83.51	84.08	83.17
175	Thar TEL	Local Coal	84.98	85.21	84.06	84.07	83.50	83.69	83.77	83.90	81.23
176	Thar-I (SSRL)	Local Coal	42.14	85.21	84.49	84.55	84.02	84.21	84.08	84.17	84.23
177	K.E_NEW_L.Coal	KE_Local Coal	0.00	0.00	0.00	0.00	82.83	82.90	82.76	83.16	83.15
178	China HUBCO	Imported Coal	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10	50.10
179	Jamshoro Coal	Imported Coal	49.36	80.73	10.01	11.74	15.33	14.01	18.34	22.03	20.30
180	Port Qasim	Imported Coal	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01	50.01
181	Sahiwal Coal	Imported Coal	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
182	FPCL	KE_Imported Coal	82.15	52.10	7.04	10.30	5.95	9.04	13.39	13.57	14.16
183	Davis	DG_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
184	Balloki	CCGT_RLNG	4.19	1.02	0.05	0.74	0.50	0.51	1.26	1.27	1.06
185	Bhikki	CCGT_RLNG	1.20	0.47	0.00	0.20	0.29	0.26	0.38	0.46	0.45
186	FKPCL	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
187	Halmore	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.30	0.30	0.30
188	Haveli	CCGT_RLNG	10.92	4.34	0.43	1.48	1.25	1.50	1.81	1.65	2.07
189	KAPCO 1	CCGT_RLNG	35.31	35.28	35.31	0.00	0.00	0.00	0.00	0.00	0.00
190	KAPCO 2	CCGT_RLNG	11.86	11.87	11.86	0.00	0.00	0.00	0.00	0.00	0.00
191	KAPCO 3	CCGT_RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Nandipur	CCGT_RLNG	36.38	36.38	36.38	21.87	0.00	0.00	0.00	0.14	0.17
193	Orient	CCGT_RLNG	37.73	22.68	0.00	0.00	0.00	0.00	0.30	0.30	0.30
194	Rousch	CCGT_RLNG	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
195	Saif	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.00	0.30	0.30
196	Saphire	CCGT_RLNG	37.73	37.73	37.73	22.68	0.00	0.00	0.04	0.30	0.30
197	Trimmu	CCGT_RLNG	26.05	11.42	3.00	4.25	2.83	2.47	4.56	5.79	6.36
198	BQPS2	KE_CCGT_RLNG	85.21	73.16	18.61	19.00	7.92	7.30	12.65	13.52	13.04
199	BQPS3	KE_CCGT_RLNG	89.81	89.80	49.57	47.98	16.74	17.70	20.92	23.64	23.18
200	KCCPP	KE_CCGT_RLNG	85.10	51.94	8.98	8.81	6.19	5.75	8.67	11.64	9.77
201	KTGTPS	KE_CCGT_RLNG	45.16	40.02	3.24	5.37	2.11	2.59	3.23	4.27	5.98
202	SGTPS	KE_CCGT_RLNG	48.00	43.72	3.78	5.89	2.33	2.85	3.81	5.11	7.31
203	BQPS1-U1	KE_ST_RLNG	10.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
204	BQPS1-U5	KE_ST_RLNG	29.34	29.97	1.68	1.71	0.28	0.45	1.00	1.05	1.39
205	BQPS1-U6	KE_ST_RLNG	16.15	15.55	1.41	1.54	0.00	0.01	0.63	0.75	0.96
206	BQPS1-U2	KE_GT_RLNG	22.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All numbers in yellow color, in this table, represent retirement of the corresponding project.)

H-6. Year-wise Installed Capacity Addition (MW)

FY	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Local Gas	Furnace Oil	Cross Border	Net Yearly Addition	Cumulative Total
2022	1,320	10,752	10,087	3,620	4,020	2,802	3,491	5,169	-	-	41,261
2023	1,980	95	965	-	660	520	-747	-1,536	-	1,937	43,198
2024	-	342	-420	-	-	2,752	-	-	-	2,674	45,872
2025	-	2,365	-	-	-	8,664	-	-	1,000	12,029	57,900
2026	300	653	-1,300	-	-	1,455	-	-	-	1,108	59,009
2027	990	2,558	-	-	-	806	-225	-1,292	-	2,837	61,846
2028	-	545	-	-	-	1,183	-	-131	-	1,597	63,443
2029	-	886	-	-	-	695	-	-727	-	854	64,296
2030	-	1,526	-172	-	-	570	-	-136	-	1,788	66,084
2031	-	2,979	-450	-	-	570	-586	-	-	2,513	68,597
Total	**4,590**	**22,701**	**8,710**	**3,620**	**4,680**	**20,016**	**1,933**	**1,347**	**1,000**	**27,336**	**68,597**

H-7. IGCEP Generation Mix 2023-2031 (GWh)

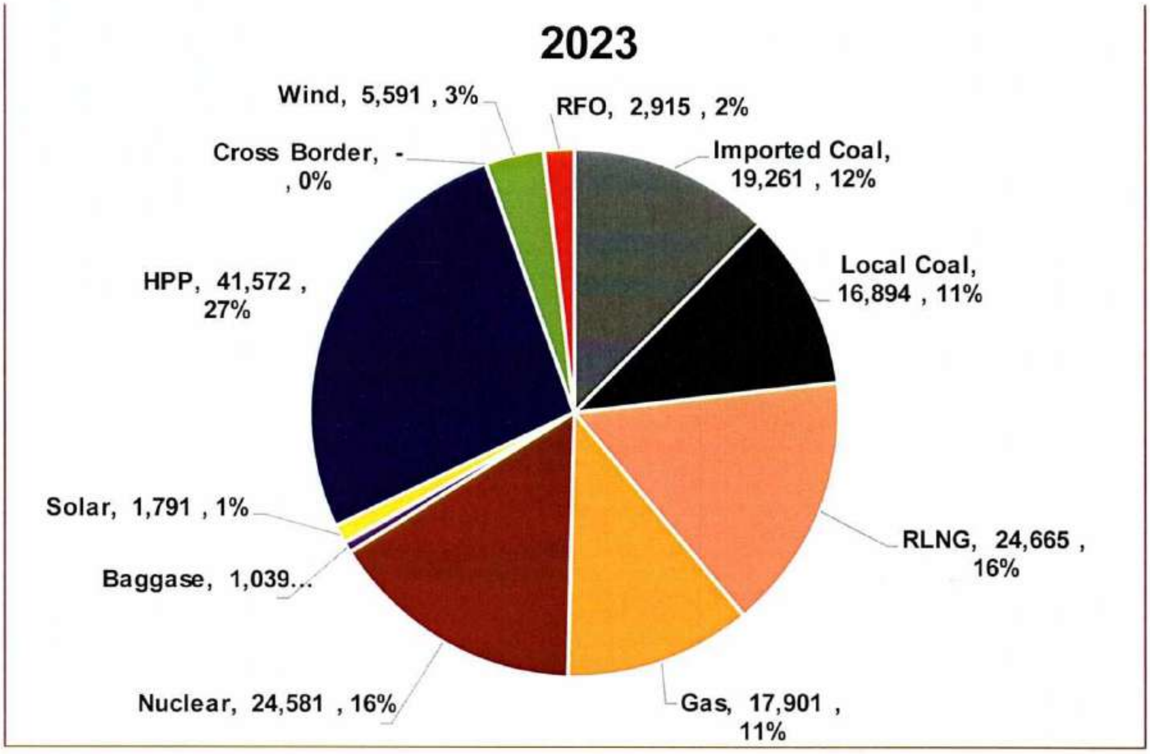


Chart H-1: IGCEP Generation Mix 2023 (GWh)

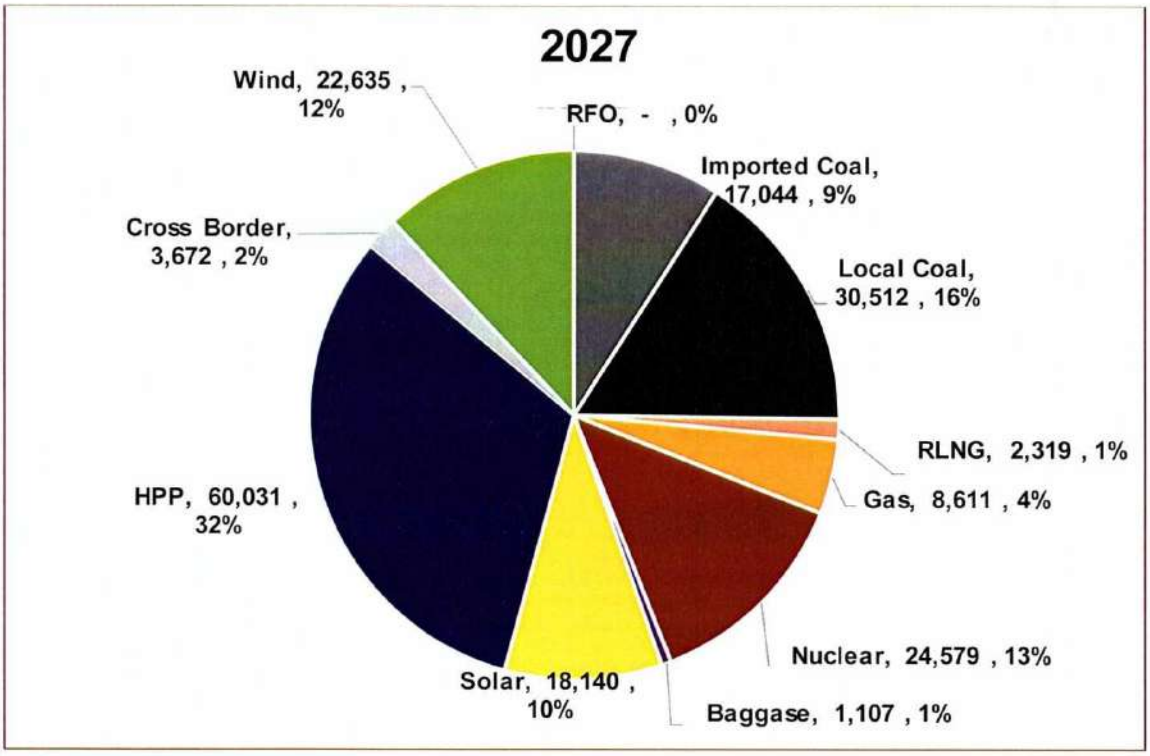


Chart H-2: IGCEP Generation Mix 2027 (GWh)

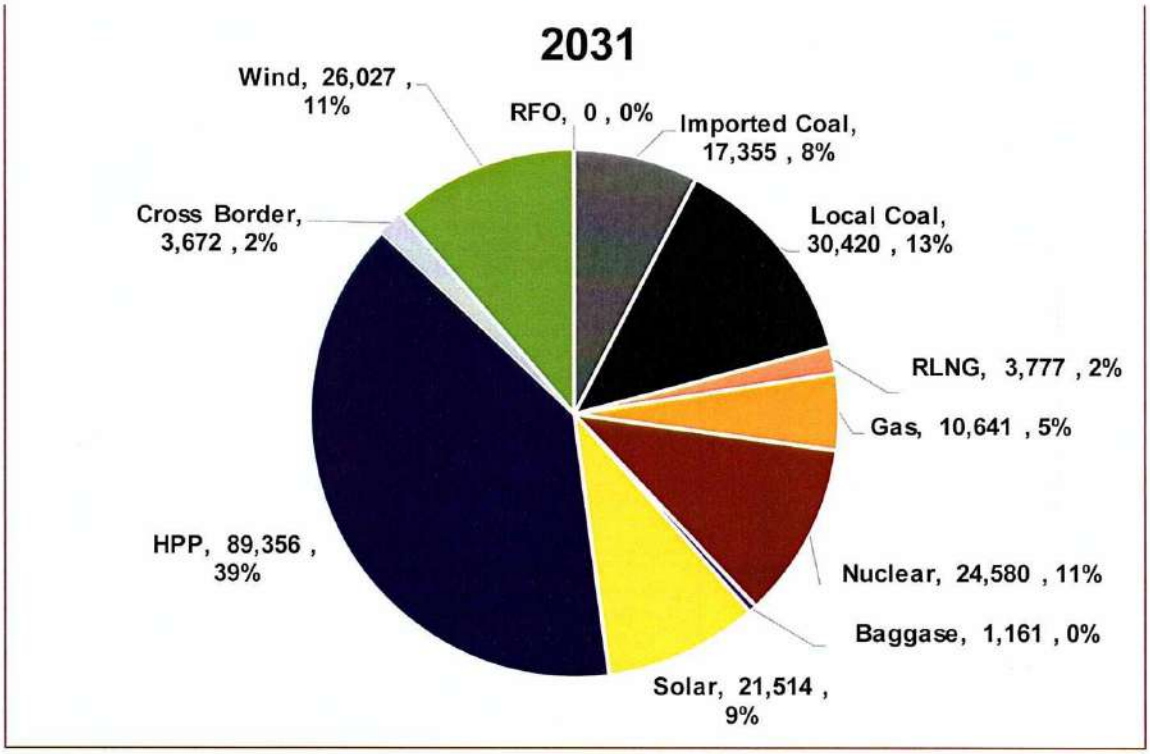


Chart H-3: IGCEP Generation Mix 2031 (GWh)

H-8. IGCEP Generation Mix 2023-31 (MW)

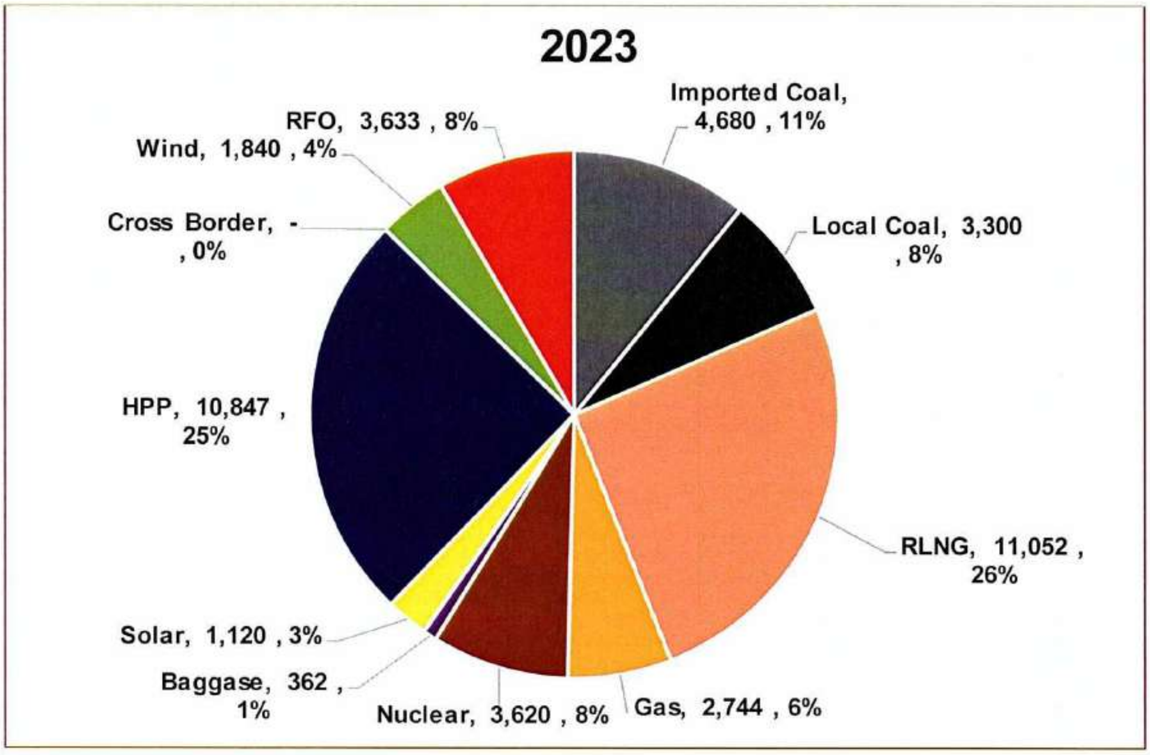


Chart H-4: IGCEP Generation Mix 2023 (MW)

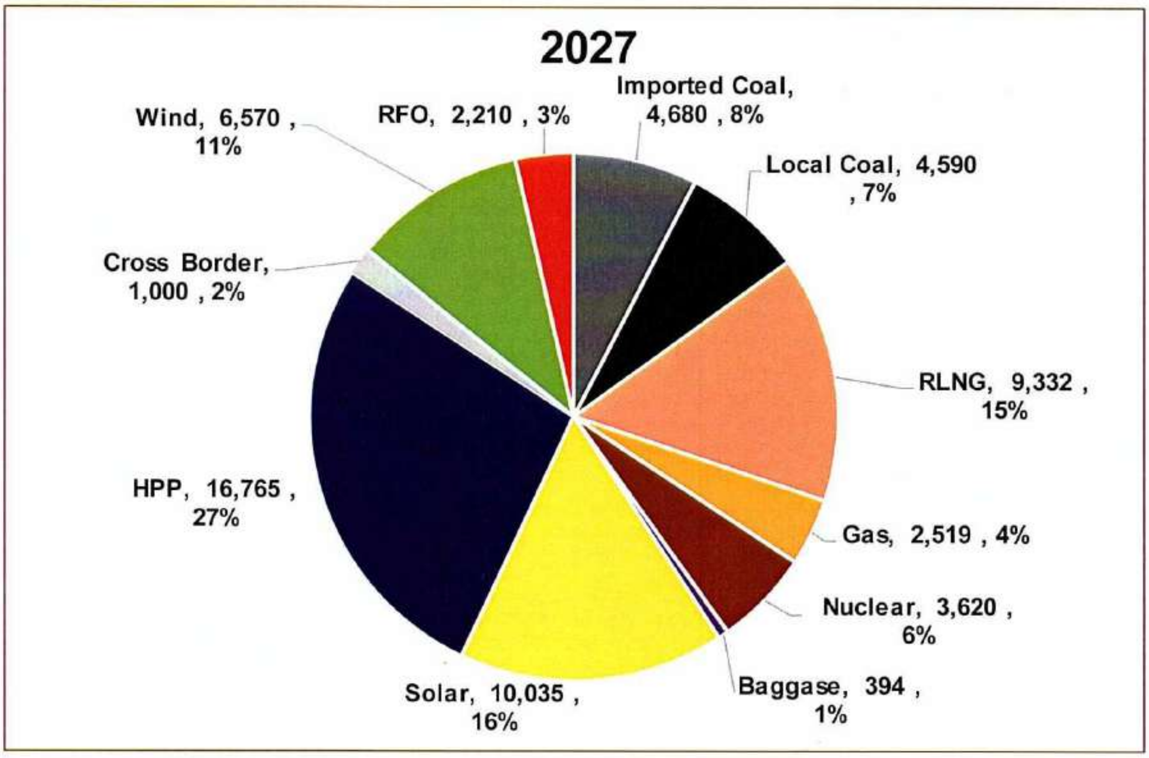


Chart H-5: IGCEP Generation Mix 2027 (MW)

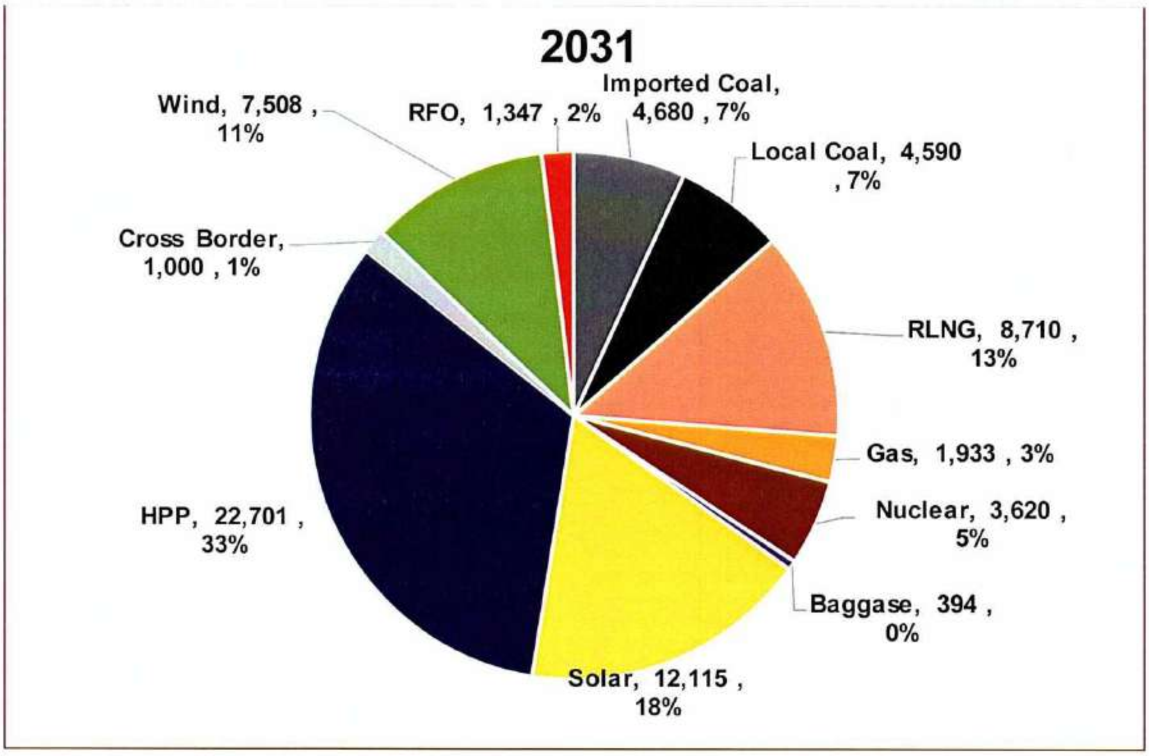


Chart H-6: IGCEP Generation Mix 2031 (MW)

NTDC

National Transmission and Despatch Company (NTDC)
www.ntdc.gov.pk

Annex-II

Comments

Of

Stakeholders

ACCESSOLAR

September 28, 2022
Our Ref: AEPL-01/09/22

The Registrar
National Electric Power Authority (NEPRA)
NEPRA Tower
Ataturk Avenue (East)
Sector G – 5/1
ISLAMABAD.

Subject: **Access Solar's 11.52 MW Solar PV IPP's Inclusion in List of Committed Projects in IGCEP.**

Dear Sir,

The subject Project was approved by the Cabinet Committee of Energy (CCoE) and was placed on serial number 01 in Category I. (Reference Ministry of Energy – Power Division's letter F-No. Tariff/RE POLICY-2019 dated April 04, 2019.

Accordingly, the Project was included in the list of the committed Projects at serial no. 29, Table 5 – 3 under para 5.8.1 of the Revised Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30, approved by the Authority vide its letter reference NEPRA/DG (LICO/LAT-01/37702-29 dated September 24, 2021.

NTDC has recently submitted IGCEP 2022-31 (reference GMT/NTDC/T-48/596-602 dated September 20, 2022), and Authority has issued notice on September 27, 2022, seeking comments for the Public Hearing of the same.

We note that from NTDC's submissions that Category I & II Projects under CCoE's decision referred to above are included in the IGCEP as committed Projects. (Para 3.6.4 & 5.9) but the Access Solar's Project in spite of being listed on serial no. 01 in Category I is not included in the list of committed Projects in Table 5.4 under para 5.9.1.

We apprehend that non-inclusion of the Project's name in the list may become a hindrance to the completion of development milestones. The Authority has recently determined the Tariff for the Project (Reference NEPRA/R/ADG(Trf)/TRF-518/ASPL/2019/17013 dated September 07, 2022) and the Project Company is awaiting its Notification to proceed with the finalization of the Energy Purchase Agreement (EPA) with CPPA-G.

We understand that projects of less than 20MW size are not listed in IGECP 2022-30 for certain procedural reasons, but it does not mean that the projects approved by CCoE and holding valid tariff determination from NEPRA, are not part of committed projects.

It is requested that the matter may kindly be clarified, and a letter issued so that CPPA-G and/or other stakeholders do not hold the project.

Early response will be greatly appreciated.

For and on behalf of
Access Solar (Private) Limited

For
Muhammad Shomail Ghalib
(Chief Executive Officer)

CC: 1. **Alternate Energy Development Board (AEDB)**
2. **Central Power Purchasing Agency Guarantee Limited (CPPAGL)**

REGISTRAR OFFICE
Diary No: 9946
Date: 29-9-2022

Fw u/o En. ER 29/9/22
- DG (LIC) cc Chairman
copy to - M (M&E/CA)
- ADG (T) - M (LIC/T)
- Cons. (Tech)
- SD (M&E)
- M.F

ACCESSELECTRIC

September 28, 2022
Our Ref: AEPL-01/09/22

REGISTRAR OFFICE
Diary No: 9945
Date: 29-9-2022

The Registrar
National Electric Power Authority (NEPRA)
NEPRA Tower
Ataturk Avenue (East)
Sector G – 5/1
ISLAMABAD.

Subject: **Access Electric's 10 MW Solar PV IPP's Inclusion in List of Committed Projects in IGCEP.**

Dear Sir,

The subject Project was approved by the Cabinet Committee of Energy (CCoE) and was placed on serial number 02 in Category I. (Reference Ministry of Energy – Power Division's letter F-No. Tariff/RE POLICY-2019 dated April 04, 2019.

Accordingly, the Project was included in the list of the committed Projects at serial no. 29, Table 5 – 3 under para 5.8.1 of the Revised Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30, approved by the Authority vide its letter reference NEPRA/DG (LICO/LAT-01/37702-29 dated September 24, 2021.

NTDC has recently submitted IGCEP 2022-31 (reference GMT/NTDC/T-48/596-602 dated September 20, 2022), and Authority has issued notice on September 27, 2022, seeking comments for the Public Hearing of the same.

We note that from NTDC's submissions that Category I & II Projects under CCoE's decision referred to above are included in the IGCEP as committed Projects. (Para 3.6.4 & 5.9) but the Access Electric's Project in spite of being listed on serial no. 02 in Category I is not included in the list of committed Projects in Table 5.4 under para 5.9.1.

We apprehend that non-inclusion of the Project's name in the list may become a hindrance to the completion of development milestones. The Authority has recently determined the Tariff for the Project (Reference NEPRA/R/ADG(Trf)/TRF-517/AEPL/2019/17004-17006 dated September 07, 2022) and the Project Company is awaiting its Notification to proceed with the finalization of the Energy Purchase Agreement (EPA) with CPPA-G.

We understand that projects of less than 20MW size are not listed in IGECP 2022-30 for certain procedural reasons, but it does not mean that the projects approved by CCoE and holding valid tariff determination from NEPRA, are not part of committed projects.

It is requested that the matter may kindly be clarified, and a letter issued so that CPPA-G and/or other stakeholders do not hold the project.

Early response will be greatly appreciated.

For and on behalf of
Access Electric (Private) Limited

For
Muhammad Shomail Ghalib
(Chief Executive Officer)

CC: **1. Alternate Energy Development Board (AEDB)**
2. Central Power Purchasing Agency Guarantee Limited (CPPAGL)

RHPCO

Riali Hydro Power Company (Pvt.) Ltd

Ref No: RHPCO/NEPRA/Riali-II HPP/2022/061

Dated: October 3, 2022

The Registrar
National Electric Power Regulatory Authority (NEPRA)
NEPRA Tower Attaturk Avenue (East)
Sector G-5/1,
Islamabad.

SUBJECT: COMMENTS ON INDICATIVE GENERATION CAPACITY EXPANSION PLAN "IGCEP 2022-2031"

Dear Sir,

NTDC in compliance to NERPA's approved Grid Code clause PC-4 (Forecasts and Generation Expansion Plan) and PC-4.1 (Generation Capacity Additions) has prepared long-term "Least Cost Generation Plan" or Indicative Generation Capacity Expansion Plan (hereinafter referred to as the "**IGCEP**" or the "**Plan**") for review and approval of NEPRA (the "**Regulator**" or the "**Authority**"). NTDC board in their 231st meeting held on 13.09.2022 approved the second edition of IGCEP for onward submission to NEPRA. The IGCEP was *inter alia* formulated on the basis of National Electricity Policy & Grid Code 2022. NEPRA *vide* their website has invited the stakeholders for submitting comments in the matter of IGCEP. We, being one of stakeholder are pleased to submit our comments for Authority's kind consideration:

We appreciate the task undertaken by NTDC to produce IGCEP in order to achieve least cost generation considering various permutations of demand scenarios. However, we believe that there are some inadequacies in this planning and it important to highlight key aspects those require attention of the Learned Authority to drive the planning process in the right direction:

Issue # 1 IGCEP has Diverted from the CCI Approved Criteria for Committed Projects

Power projects considered as committed projects based on the criteria stipulated in Assumption Set approved by CCI is shown in the Figure 5-2 of IGCEP. **One of the CCI approved criteria was that the project shall be enlisted as Committed, who has obtained LOS as of December 2020 for private sector projects**. However, certain hydro power projects such as 7.08 MW Riali-II (the '**Project**") which was *inter alia* part of NEPRA approved IGCEP 2021-30 as a committed project has now been **excluded** from the IGCEP.

The Project was issued LOS by PPIB on 16th October, 2019 and Energy Purchase Agreement was signed with CPPA-G on 16th April, 2020. However, the Project is nowhere to be found in the list of IGCEP Committed Projects (table 5-4).

The section 5.2 of IGCEP provides the assumptions upon which the Plan is created. In the point 20 of this section it is stated that candidate as well as committed power projects under 20 MW and connected below 132 kV (and hence, not in central dispatch) **have not been considered**. Such assumption was never been part of CCI approved criteria for Committed Projects or of NEPRA approved IGCEP 2021-30.

REGISTRAR OFFICE
Diary No: 10266
Date: 04.10.2022

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RHPCO

We believe that any project, where LOS is issued by the relevant entity, EPA is signed by CPPA-G and the DISCO's owned grid station is recipient of the power generated by that project, shall be enlisted as Committed Project in IGCEP. Moreover, according to our understanding, power projects located in K-Electric are yet to be centrally despatched. Besides, the existing & upcoming solar projects may not be centrally dispatched or could be connected below 132 kV level.

We request NTDC to reconsider their aforesaid assumption regarding power projects below 20 MW, which is divergent to CCI approved criteria for committed projects, and reinstate projects like 7.08 MW Riali-II Hydro Power as Committed Project in a similar way as of IGCEP 2021-30.

Issue # 2 IGCEP is a Non-Committal Document

It is repeatedly mentioned in the IGCEP that the optimization of any generation project under Section 6.4 of the IGCEP shall not confer any right or any privilege or any confirmation of the generation project in question in relation to its implementation or execution. As highlighted, the IGCEP is an **indicative** development plan and confirmation of any new generation project for **future procurement** shall be subject to **approval of respective competent authority** as per applicable criteria prescribed in prevailing policies, rules and regulations. This statement has raised ambiguity in investors mind. The investors are confused and wants to know that who is the competent authority that finally confirms the approval of project for execution/implementation? NTDC in their Disclaimer is taking no responsibility or liability of implementing the IGCEP optimized projects.

The Authority in their various decisions has either **rejected** the tariff petitions filed by the sponsors of their projects or in some cases has **withdrawn** the given tariff, while stating the reasons that their projects has first to be optimized in IGCEP before they initiate process of issuing tariff.

The Authority has relied on IGCEP as a pre-condition for issuing tariff, however NTDC has repeatedly mentioned that their Plan is essentially a non-committal in nature, without any reliance or obligations. We believe that this has created a chicken & egg situation, however NTDC must take some responsibility for their Plan. Keeping in view the Grid Code 2022 and NEPRAs upcoming Open Access Policy, NTDC must take responsibility and undertake negotiations & finalizations of **Connection Agreements** for the optimized projects. The same shall be explicitly mentioned in the IGCEP.

Issue # 3 Transmission System Expansion Plan ("TSEP")

It is mentioned in the Plan that it is **exclusive** of any costs relating to power system evacuation and transmission system expansion for **optimized generation project**. The transmission system expansion and related costs shall be allocated to the optimized generation project following the approval of the **transmission system expansion cost allocation criteria** by CCI. **<u>This may impact the selection /optimization or ranking of the optimized generation project for which NTDC shall in no circumstances be held liable or accountable</u>**.

RHPCO

It may be noted that this is the second edition of IGCEP, and interestingly the CCI has yet to approve the TSEP cost allocation criteria. We understand that only after the approval of such criteria by CCI, NTDC will commence their work on TSEP. By observing the current & previous practices, we believe that another two years are required for formulation of TSEP.

NTDC is requested to take a proactive approach for the timely formulation of TSEP, as they have mentioned that the optimized projects could be impacted after TSEP. Therefore, **TSEP is an equally critical for planning as of IGCEP**, and delaying the finalization of TSEP will dampen the importance of IGCEP.

Issue #4 Aggressive Induction of Solar

The IGCEP has forecasted an additional 4,320 MW of net metering solar electricity in the system, i.e., 480 MW annually. The existing contribution from the net metering electricity to the system is 160MW. However, the government efforts of adding 4,320 MW of net metering solar energy to the system within the next decade are likely to hit a snag due to inconsistent/frequent changes in policies by the government. Moreover, investments in the financing of renewables need to be accelerated by offering green financing tools, mechanisms, and incentives to localize the technologies-based solutions to provide a cost-effective pathway for adoption.

Additionally, the IGCEP has forecasted an additional 8,350 MWp of solar PV (includes utility scale and feeder based/DG) in the system. The intermittent nature of the dominant RER e.g., solar photovoltaic (PV) and wind systems, due to climatic conditions poses operational and technical challenges in their effective integration by hampering network reliability and stability. There are complications and costs involved with connecting big solar projects to the grid, and after incorporating those, big solar projects may not be financially viable. According to a study, Pakistan grid system has a capacity to absorb around 5 percent load of solar. Therefore, there is need is to study the grid and make decisions accordingly. Rushing into such projects can have unintended consequences.

→ Moreover, Solar cannot cater to the summer peak load which is usually from 7PM to 11PM. Solar can only produce in daytime. That is why, bigger size plants in solar are not recommended without massive investment in grids up gradation and even than the presence of spin base-load might be required. As someone aptly put, solar & wind deployment targets **should not** be fed into the IGCEP but rather should come out from it.

RHPCO

SUBMISSIONS FOR AUTHORITY'S CONSIDERATION:

In view of the foregoing, it is respectfully prayed:

i. That the IGCEP may kindly be revisited/revised keeping in consideration of our above-mentioned comments;

ii. That the NEPRA Authority may direct NTDC to fully follow the CCI approved criteria for Committed Projects in letter & spirit without creating any prejudice against projects under 20 MW;

iii. That the Project Sponsors of Riali-II Hydro Power has relied upon the terms and conditions, incentives & concessions provided in the Power Policy, commitments made in the Letter of Support issued by PPIB, right & responsibilities under the EPA executed between the Project Company & CPPA-G and millions worth of investment that have already been incurred at site. Therefore, any changes in the Project commissioning / timelines mentioned in IGCEP 2021-30 or deviation from CCI ~~approved criteria for~~ Committed Projects will cause an irreparable loss and damage to the Sponsors.

Yours Sincerely,

(Syed M. Hussain Gardezi)
Director (Development)

Cc:

- Managing Director (PPIB)
- Managing Director (NTDCL)
- Office Copy.

Riali Hydro Power Company (Pvt.) Ltd

RHPCO

Ref No: RHPCO/NEPRA/RIALI/2022/063 Dated: October 20, 2022

REGISTRAR OFFICE
Diary No: 11033
Date: 21-10-2022

Fw 21/X/22
"Chairman
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- ADG (T)
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- LA ...

The Registrar
National Electric Power Regulatory Authority (NEPRA)
NEPRA Tower Attaturk Avenue (East)
Sector G-5/1.
<u>Islamabad.</u>

SUBJECT: <u>ADDITIONAL COMMENTS ON INDICATIVE GENERATION CAPACITY EXPANSION PLAN "IGCEP 2022-2031"</u>

Honorable Chairman Sahib,

At the onset, I would like to congratulate you and your team for successfully organizing the IGCEP public hearing in a very cordial & efficient manner. There is no doubt that hearing on such a complex & important issue could not have been managed better.

The undersigned has participated in the IGCEP hearing as well as furnished comments on the draft IGCEP through our Riali Hydro Power Company Pvt. Ltd. During the proceedings of the aforesaid hearing, the undersigned has noted certain points which are being presented hereunder for your review and clarifications from relevant stakeholders:

1- COMMITTED PROJECTS IN IGCEP

→ During the proceedings while discussing the issues about Chashma-V project; NTDC rightly argued that enlisting the project as Candidate in IGCEP instead of Committed was the decision of CCI; which NTDC cannot change. Hence, NTDC has accepted the fact that CCI approved/provided criteria for committed projects in IGCEP are binding and NTDC cannot willfully deviates from that criteria.

→ However, in contrary to NTDC's above claim that the deviation from CCI's approved criteria is not possible for them, NTDC has not included two hydro power projects (i.e. Riali-II & Kathai-II) in the current iteration of IGCEP which were issued LOS as of December 2020, and **were part of NEPRA approved previous iteration of IGCEP as Committed Projects.**

→ **We believe that exclusion of these two hydro power projects from the IGCEP committed list is a clear violation of CCI approved criteria and we request Authority as well as NTDC to enlist both projects as Committed in the current iteration of IGCEP.**

2- PUBLIC SECTOR FUNDED PROJECTS

During the proceedings you have stated that the list of committed projects in IGCEP will reduce with time, as new projects will be only optimized on their merits. We wish that your statement become reality, however we believe that such conclusion is not possible unless all public sector projects are forced to provide their upcoming projects data to NTDC/NEPRA for optimization in IGCEP **prior** to initiating works on the project sites.

The country has suffered a lot from these public funded (so called National Interest) projects where NEPRA's three stage tariff mechanism, <u>IGCEP optimization, lump sum turnkey EPC</u>

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RHPCO

based contracts are not enforced. The implementing agencies of these public sector projects often approach NEPRA for tariff at commercial operations date (COD) stage and at that stage NEPRA has no choice but to issue generation license/tariff to these projects.

Therefore, Government of Pakistan must make it mandatory to implement only those power projects that those are optimized by IGCEP and given initial stage tariff by NEPRA, irrespective of the fact that such projects are implemented under public sector, national interest or private sector.

3- IGCEP WITHOUT TSEP IS INCONCLUSIVE

The undersigned wants to reiterate that the importance of Transmission System Expansion Plan ("TSEP"); as without TSEP the importance of IGCEP is limited. The NEPRA Authority has stated that only those projects those are optimized in IGCEP will be issued generation license and tariff by them. Once the project is optimized in IGCEP and tariff issued, the project sponsors can proceed to implement the project and carryout substantial investment in purchasing land for their projects. However, we would like to highlight a scenario where the project is optimized in IGCEP and after receiving the tariff. the sponsors purchase land and later the project is removed from IGCEP due to non-optimization of the same project after the issuance of TSEP.

NTDC has pointed out in IGCEP that the transmission system expansion and related costs shall be allocated to the optimized generation project following the approval of the **transmission system expansion cost allocation criteria by CCI. This may impact the selection /optimization or ranking of the optimized generation project for which NTDC shall in no circumstances be held liable or accountable**.

Therefore submission of TSEP alongwith IGCEP is critical for smooth development of a project and we request NTDC to finalize the TSEP at the earliest please.

4- IGCEP AND POWER OFFTAKE MECHANISM

During the hearing you have inquired NTDC to confirm the project offtake mechanism used for IGCEP (either it is Take or Pay OR Take & Pay). The NTDC during the proceedings admitted that the project offtake in IGCEP is based on Take & Pay basis. However, in section 5.4 of IGCEP it is stated that "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 50% for existing imported coal-based power projects (Sahiwal, China HUBCO & Port Qasim), and three low btu gas-based projects (Uch-II, Engro and Foundation)". Therefore all the thermal based power projects in IGCEP are based on Take or Pay offtake. We would like to know what offtake criteria is used by NTDC for IGCEP proposed upcoming thermal based projects?

We are of view that the selection of offtake mechanism (Take or Pay OR Take & Pay) do not fall under the purview of IGCEP or NTDC. The power offtake mechanism is a policy matter that fall under the purview of CCI. The applicable/CCI approved power policies such as GOP

RHPCO

Power Generation Policy 2015 provides clarity of power offtake mechanism and its applicability. It was declared and represented in the CCI approved Power Policies that the hydropower projects will be dispatched on highest priority as the generation cost was most economical. These hydropower projects were eligible for two part tariff comprising of Capacity Purchase Price (CPP) and Energy Purchase Price (EPP).

The NEPRA Authority may also consider the fact that that under and pursuant to Article 154 of the Constitution of Islamic Republic of Pakistan (**Constitution**) the policy formulation is the exclusive domain of the Council of Common Interests (**CCI**) which states as under:

"The Council shall formulate and regulate polices in relation to matters in Part II of the Federal Legislative List and shall exercise supervision and control over related institutions."

The subject of 'Electricity' is included at Entry No. 4 in Part II of the Federal Legislative List of the Constitution and hence the CCI is the sole constitutional body to formulate polices with regards to subject of Electricity.

We believe that usurping the mandate solely vested in the CCI by effecting change in the 2015 Power Policy which shall hurt and adversely affect the power projects being implemented under that Policy, without their recommendations and input at the constitutional forum of the CCI is tantamount to the subversion and expropriation of their rights.

Moreover the right of the investors who have been issued LOI's by federal entities under 2015 Power Policy shall be protected under the doctrine of non-application of any law or policy retrospectively as retrospectivity is barred under the Constitution

The change in the Power Policies is coram non judice as the policy change and sanction of departure from the provisions of the Power Policies are the exclusive jurisdiction of the CCI in a duly convened constitutional forum meeting and not otherwise and again it shall not affect the vested rights of the investors who were already issued permits by the government.

RHPCO

SUBMISSIONS FOR AUTHORITY'S CONSIDERATION:

In view of the foregoing, it is respectfully prayed:

i. That the IGCEP may kindly be revised/revisited keeping in consideration of our above-mentioned comments:

ii. That the NEPRA Authority may direct NTDC to fully follow the CCI approved criteria for Committed Projects in letter & spirit without creating any prejudice against projects under 20 MW:

iii. That the NEPRA Authority may kindly advice the relevant quarters of the Government to streamline power project development process in accordance to the process followed by the private sector:

iv. That the NEPRA Authority may consider issuing timeline to NTDC for the submission of TSEP on annual basis:

v. That the investors of power projects that are advertised by the federal government has relied upon the terms and conditions, incentives & concessions provided in the 2015 Power Policy, commitments made in the Letter of Intent issued by PPIB; and based on these commitments have invested millions on project development. **Therefore, any changes in the Project offtake which is *inter alia* in contradiction to the power offtake mechanism mentioned in the Policy will cause an irreparable loss and damage to the Sponsors.** Moreover, any change in incentives provided in the Policy will convey a negative message to investor(s) that the GOP policies are not to be trusted and relied upon. The role of regulator is pivotal to ensure a balance between investors and consumers. Any imbalance would jeopardize the continuity of investment in power generation sector.

vi. That the NEPRA Authority before issuing tariffs on Take & Pay basis may kindly consider inviting leading banks / lenders to seek their point of views on power projects offtake mechanism. Since the lenders are upto 80% shareholders of the power projects during the debt servicing period; therefore we believe that their inputs are essentially required for the bankability of the projects.

Yours Sincerely,

(Syed M. Hussain Gardezi)
Director (Development)

Cc-

1- Mr. Ali Zain Banatwala, Deputy Managing Director (SO), NTDC.
2- Mr. Shah Jahan Mirza, Managing Director PPIB.
3- Mr. Waqas Bin Najib, Member (Energy), Ministry of Planning Development & Special Initiatives

AEL

ALTERN ENERGY LIMITED

Descon Headquarters:
18-km, Ferozepur Road, Lahore.
Tel: +92-42-3599 0034, Fax: +92-42-3540 1938-39

Chairman
National Electric and Power Regulatory Authority ("**NEPRA**")
Attaturk Avenue (East)
Sector G-5/1
Islamabad

Ref: AEL/CORP/ 1215
Date: October 04, 2022

11/10/2022

General Manager (Technical)
National Transmission and Despatch Company Limited ("NTDC")
611 – WAPDA House
Lahore

Subject: **Correction regarding the status of Altern Energy Limited ("AEL/the Company") in the Indicative Generation Capacity Expansion Plan (IGCEP) 2022-31**

Dear Sirs,

This is written with reference to the above captioned subject. AEL is aware that the most recent iteration of IGCEP has been prepared by NTDC and submitted to NEPRA for the regulator's review and approval. In this regard, and to ensure the integrity of the data as contained in IGCEP 2022-31, AEL hereby submits the following clarification(s) regarding the status of the Company:

(a) Per Chapter 5 (*Assumptions*), section 5.2, assumption number 31 of IGCEP 2022-31, it has been provided that *"140 MW Habibullah Coastal (HCPC) and **31 MW Altern Energy Limited (AEL) have not been considered in the existing installed capacity owing to** termination of Gas Supply Agreement (GSA) and **de-licensing by NEPRA, respectively**"*.

(Emphasis added).

Registrar
DG (L/C)

(b) Assumption number 31, as cited above, is based on the erroneous presumption that NEPRA has de-licensed AEL. The factual position is that while AEL's Generation License expired on September 21, 2021 the Company has applied to the Authority for the extension / renewal of its Generation License. The same is currently under process and no determination pertaining to de-licensing of AEL has been issued by NEPRA.

(c) In addition to the foregoing, the Company would also like to draw the attention of your offices to the ongoing validity of AEL's project documents. Thus, AEL's Power Purchase Agreement is valid till 05.06.2031 and its Implementation Agreement, as executed with the Government of Pakistan is also valid till 2031. Since neither of these agreements have been terminated and are in full force and effect, AEL cannot be excluded from the list of existing installed capacity.

In view of the above submissions, we request NTDC to kindly re-visit the AEL entry in IGCEP 2022-31 and ensure that its status is accurately reflected therein.

Looking forward,

For and on behalf of
ALTERN ENERGY LIMITED

Umer Shehzad Sheikh
Chief Executive Officer

REGISTRAR OFFICE
Diary No: 7033
Date: 11/10/22

CHAIRMAN
Dy No. 6962
Date: 06.10.2022

Fw ufo & n.e.P
11/X/22
- DG (L/C)
Copy to
- ADG (T)
- Cms (Tech)
- SA (M&E)
- M.P
cc: Chairman
- m (M&E) (A)
- m (L/T)

CC: Managing Director, PPIB, 2nd Floor, Emigration Tower, Sector G-8/1, Islamabad.
The Registrar, NEPRA, NEPRA Tower Attaturk Avenue ,Sector G-5/1, Islamabad.

Annex-III (5)

COMMENTS OF ATLAS POWER ON IGCEP

1. In the table 6-3: PLEXOS Annual Addition of Power Projects 2023-2031, there is addition of power generation through solar under the portfolio of 'net meter' with dependable capacity of 480MW for each year starting from 2022-23 till 2030-31. This portfolio has also been given the status of 'committed,' which, in our opinion, is not a pragmatic approach; therefore, we suggest reducing this figure to 250MW, keeping in view the unavailability of solar equipment and a reduced rate for settlement of net metered units. The addition of solar through 'DG' upto 250 MW in 2023-24 is more realistic and may be given the 'committed' status.

2. We suggest that the projects falling under Category III be part of IGCEP even under bidding and be given a fair chance to enhance the solar portfolio in the utility-scale category rather than net metering of 480MW each year.

3. PPDB has showcased WtE projects in Punjab, which are also a part of the Punjab RE portfolio; the brief detail of such projects are given below, and we understand that these projects are strategic and an introduction to 'new technology that should be added to the Candidate list of IGCEP as for next ten years such projects will be in line due to their importance and strategic nature.

4. In the section C-4. List of Projects up till 2031 (Committed + Optimized), Taunsa Project, must be marked as a 'committed' project as if the project has to be commissioned in 2028-29, the work has to be started from the year 2023 and without adding it in the committed list financing can not be obtained.

Annex-III (6)

Chairman

From: ARF ARF <marfhs1051@gmail.com>
Sent: Saturday, 8 October, 2022 11:57 PM
To: Registar
Cc: NEP TAUSEEF HANIF FAROOQI. Chairman, Imran Bukhari. PA. Sana.; NEP RAFIQUE AHMED SHAIKH PA Nazir Ahmed; NEP ENG. MAQSOOD ANWAR KHAN Member KPK.
Subject: Notice for seeking comments in the matter of IGCEP 2022-31.

18-10-2022

9.10.2022

Registrar,
N. E. P. R. A.,
Nepra Tower,
Ataturk Avenue East,
Sector G-5/1,
Islamabad.

This is with reference to the above cited subject on which the Authority has invited comments.

On going through the report submitted by NTDC the undersign noticed that in the solar renewable energy section nothing has been mentioned about addition that will take place by installation of solar energy panels by DGs in the next about 5 years as has already been publicly stated by the honourable Secretary Power Division which widely appeared in print, electronic & social media and was also commented by many. As you are very well aware that according to the honourable Secretary Power Division 3600 MW of additional power will come from DGs which is quite substantial and must be taken care of and NTDC may be asked to reduce that much addition from other sources which will be burden on the exchequer (GOP).

Further comments will be offered at the hearing.

M. Arif Bilvani.

Sent from my iPhone

Registrar
DG (Licensing)
18/10/22

Copy to
- DG (T)
- Chairman
- M (LEE) (T)
- M (Lic) (T)
- Ams (Tech)

CHAIRMAN
Dy No 7052
Date 10.10.2022

10810
18.10.2022

October 6, 2022

The Registrar

National Electric Power Regulatory Authority

P482+HFF, NEPRA Tower

Opposite to Federal Flood Commission (East Ataturk Ave, G-5/1, G-5)

Islamabad

THE IGCEP: NEPRA NEEDS TO CONSULT ALL STAKEHOLDERS IN ORDER TO AVOID SERIOUS ENERGY SUPPLY DISRUPTION ISSUES

Background

The Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30 is a long-term outlook related to the Power Sector, with its main focus being to shut down inefficient electricity generation and replace it with new plants based on other-than-fossil-fuels.

Any Plan worthy of its name must take into account all the stakeholders affected directly or indirectly by its implementation. Otherwise the results, far from being as envisaged by the Plan, could be very counter-productive and self-harming.

The stakeholders involved in ensuring Pakistan's Energy Security are

The Upstream Oil Sector	Exploration and Production
The Downstream Oil Sector	Refining, Oil Marketing
The Oil Transportation Sector	Pipelines, Road, Railways
The Ports & Shipping Sector	Port Qasim Authority (PQA), Karachi Port Trust (KPT)
The LNG Sector	Regasified Liquefied Natural Gas, Engro Vopak
The Natural Gas Sector	Primarily locally available Natural Gas and Associated Gas, SNGPL, SSGC
The Power Sector	WAPDA, K-Electric, Power Distribution Companies (DISCOS), Independent Power Producers (IPPs)
The Hydropower Sector	

REGISTRAR OFFICE
Diary No: 10286
Date: 7-10-2022

For information c/a pl.
— DG (Lic.)
— MF
— Cons HC Team
— CRE/Tech
cc: Chairman
— M(MER/CA)
— M(Lic./F)
7/X/22

The Nuclear Power Sector

The Solar Energy Sector

Additionally, the Regulators - NEPRA, OGRA, Ministry of Energy

All of the foregoing stakeholders play a role in ensuring sustainable energy to the citizens of Pakistan. Any action by any of them impacts the energy supply chain in one form or the other. Each of these stakeholders has short, medium and long-term plans underway to meet the growth needs of the energy sector.

For example, our Local Refineries provide 30 percent of our Gasoline needs, and 50% of our High Speed Diesel needs. These Refineries depend on 15 percent local crude and 85 percent is imported to keep them operational. Our Local Refineries have been operating at close to or less than 60% over the last few years: Reduced lifting of Furnace Oil by OMCs/Power Plants was the main reason. Some refineries also shut down in November/December 2021. Shutdown of a local Refinery not only leads to lower availability of Refined Product but also directly impacts local Oilfield Production and that of Associated Gas (especially for ARL, which is solely dependent on local crude).

All the Refineries are targeting collective investment of Billions of Dollars in upgrading their facilities to not only enhance local availability but also improve the quality of the transport fuels Petrol and Diesel that they produce.

What is disconcerting to note, however, is that the authors of the NTDC/NEPRA IGCEP are either not aware of these very capital-intensive Refinery plans or have chosen to ignore them completely.

How else would one explain the proposal to totally phase out Residual Fuel Oil (RFO) by 'retiring' most power plants using RFO by the year 2023 (i.e. next year?)? Please refer to Table 5-2 on Page 41 of the IGCEP, where closure of 3,620 MW by 2023 is proposed. Another 1,423 would be retired in 2027. As per Chart 6-6 Page 78 by 2025 RFO use would reduce to only 3,506 MW from the 6,506 MW in 2021.

The Refineries of Pakistan collectively produce about 8,300 Metric Tons per Day of Residual Fuel Oil, capable of feeding about 3,000 MW electricity generation. Their Up gradation Projects will take 3-4 years from Financial Close which is dependent on the terms of the new Refining Policy still under discussion with the Ministry of Energy Petroleum Division (MoEPD). This means that they would be able to reduce their RFO production to almost less than 5% from the present 20-30% by the year 2026/2027. These projects will be able to ensure payback only if the Refineries are operating at close to 100% capacity and generating revenues. Imagine what happens when they cannot dispose of their RFO from 2023: they will be forced to shut down thereby not supplying the Petrol and Diesel as well as the Jet Fuel that they do now, leading to more imports, more pressure on the already under pressure Ports, thereby impacting adversely the entire supply chain. Furthermore, the local Oil production would start shutting down thereby impacting the availability of associated gas and possibly impacting the E&P sector irreversibly.

We do not have enough fiscal resources to meet our ever-growing needs of the basic essential commodities to keep our populace supplied. The poor segment of our population is growing and facing survival challenges on a daily basis

All our indigenous resources have dwindled and we continue to rely more and more on costly imports at a time when our Rupee/Dollar parity is seriously compromised and the international market keeps heading north due to war and pandemic

The bottom Line here: *Maximum Use of Indigenous Energy Resource, Reducing Consumption and Minimizing Imports is the only solution*

The recent developments on the international markets as well as the local scenario due to wars, political upheavals and pandemics, are adding to Pakistan's woes due to the continuous increase in the price of Petroleum Oil Liquids (POL) as well as of RLNG.

The situation at the country's borders and the fight against terrorism being addressed by our valiant Armed Forces, furthermore, requires a National strategy that ensures timely and without-disruption POL supplies especially for the Armed Forces.

<u>It is proposed that all stakeholders impacted by the IGCEP must coordinate to readdress the proposals in order to avoid serious impacts on the Energy supply chain of the Country.</u>

It is hoped that the Hearing planned by NEPRA on the issue on October 19, 2022 will discuss this and other related issues threadbare.

LET US DO WHAT IS BEST FOR PAKISTAN

Sincerely

Sd. Dr. M. Ilyas Fazil

<u>Islamabad, Pakistan</u>

GUJRANWALA ELECTRIC POWER COMPANY LIMITED

Ph.#055-9230145-47

Email:dgmirad@gepco.com.pk

OFFICE OF CHIEF EXECUTIVE OFFICER, GEPCO LTD.
(Market Implementation Regulatory Affairs Department)
Wapda Rest House, W-Block, Peoples Colony, Gujranwala

No. 1232-35 /GEPCO | Dated 05/10/2022.

Fw ufo 2n.ell
- DG (Lic)
copy t
- SA (HEE)
- Cons. (CBC)
- PDG (CT)
- Cons. (Tech)
- m.F
11/10/22
Chairman
- M (HEE/CE)
- M (Lic/T)

The Registrar,
National Electric Power Regulatory Authority (NEPRA),
NEPRA Tower, Attaturk Avenue (East), G5/1,
Islamabad.

Subject: **GEPCO COMMENTS IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-2031 (IGCEP-2022)**

Reference: NEPRA Notice for seeking comments and public hearing on subjected matter published/advertised on 27-09-2022.

In compliance with the NEPRA Notice on subjected matter, we (GEPCO) has reviewed the IGCEP-2022 which was prepared by NTDCL and submitted the same for review and approval of the Authority. Certain observations/comments are hereby laid down in front of honorable Authority for consideration please.

1. 5.38MW Chianwali Hydropower Project which was the part of Committed Project in NEPRA Approved IGCEP-2021 at Sr.#15, Table No. 5.3. Now the said project is not the part of IGCEP-2022 neither as Committed Project nor as Existing Project. It is pertinent to mention here that Interconnection of the Project with the GEPCO's System (at 11KV Level) has already been completed..The said Power Plant is currently in Commissioning/Testing stage and contractual arrangements with PPDCL are in final stages.
2. Also, 7.64MW Head Marala Hydropower Project is not a part of IGCEP-2022, which was a part of Existing Project in NEPRA Approved IGCEP-2021 at Sr.#37, List B-1, Annexure B. As GEPCO is already in a Pre-COD Side Agreement with PPDCL regarding said project since 31-07-2017 and further contractual arrangements with PPDCL are in final stages.
3. The year wise Share of Net Metering in Total Installed capacity as listed in Chart 6-3 in IGCEP-2022, described as addition of 480MW each year starting from Year 2023, seems irrational and not associated with ground realities, considering the accelerating number of net metering Authority may kindly direct adoption of rational figures than an addition by fixed quantity.

REGISTRAR OFFICE
Diary No: 10502
Date: 11-10-22

(IRFAN RAFIQUE)
Director General (MIRAD)
GEPCO H/Q Gujranwala

Copy to:-

1. P.S.O to CEO GEPCO.
2. General Manager (Technical) GEPCO Gujranwala.
3. Master file.

Annex-III (11)

PEDO

PAKHTUNKHWA ENERGY DEVELOPMENT ORGANIZATION

Government of Khyber Pakhtunkhwa Peshawar

PEDO House, 38/B-2, Phase-V, Hayatabad, Peshawar. Tel: (+92-91) 9217246, Fax (+92-91) 9217003

No. — /PEDO/CEO/DREPP/NEPRA 8972-74

Dated: October 18, 2022

To

Mr. Shakil Ahmed
Additional Director (Registrar Office)
National Electric Power Regulatory Authority (NEPRA)
NEPRA Tower, Ataturk Avenue (East), G-5/1, Islamabad

Subject: **NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-31 (IGCEP-2022)**

This is with reference to your letter No. NEPRA/DG(Lic)/LAT-01/18675-33 dated September 27, 2022, wherein the Authority has directed all stakholders to submit their comments on the draft IGCEP 2022-31 for the upcoming public hearing to be held on October 19, 2022.

2. In this regard, GoKP/PEDO has reviewed the draft IGCEP 2022-31 and appreciate the same, however, we would like to put forward the enclosed views/comments for consideration of the Authority **(Annex-I)**.

3. It is requested that the enclosed comments may be considered by the Authroity and the mentioned Hydro and Solar PV projects may kindly be included in the IGCEP 2022-31, in order to promote the development of indigenous energy resources of the Khyber Pakhtunkhwa province.

18/x/2022

Chief Executive Officer
PEDO, Peshawar

Copy for information to:

1. Secretary to Energy & Power Department, Peshawar
2. Chief Engineer RE, PEDO, Peshawar

Chief Executive Officer
PEDO, Peshawar

Annex-III (9)

HCPC HABIBULLAH COASTAL POWER COMPANY

Our Ref No: HCPC\NEPRA\07102022

Dated: October 7th, 2022

Registrar NEPRA
NEPRA Tower
Attaturk Avenue (East)
G-5/1, Islamabad.

SUBJECT: NDICATIVE GENERATION CAPACITY EXPANSION PLAN (IGCEP) 2022-31

Dear Sir,

This is with reference to your advertisement in newspaper for the comments on Indicative Generation Capacity Expansion Plan 2022-31.

Attached please find the Habibullah Coastal Power Company Private Limited (HCPC) comments on the IGCEP 2022-31.

We request NEPRA to keep HCPC as an operating asset in the IGCEP 2022-31

Regards,

Aali Muazzam

CEO - HCPC

Habibullah Coastal Power Company (Pvt.) Limited

Corporate Office:
D-180 Block - 5
Clifton, Karachi - Pakistan
Tel. +92 21 322 4301 – 6
Fax: +92 21 3587 6621

Registered Office:
HCPC Plant Site
Killi Almas Road
Sheikh Manda Quetta
Tel: +92 81 2881 007
Fax: +92 81 2881 1008

HABIBULLAH
COASTAL
POWER
COMPANY

INDICATIVE GENERATION CAPACITY EXPANSION PLAN (IGCEP) 2022-31

Following are the HCPC comments on the IGCEP 2022-2031 plan submitted by NTDC in your good office.

1. HCPC is the only power plant in Quetta city. The plant was commissioned in 1999 and signed Indigenous Gas Supply Agreement (GSA) with Sui Southern Gas Company Limited in 1996 for a period of 20 years. The Plant Net Electrical Output (NEO) was 129.15MW as proved in last Annual Dependable Capacity Test held in 2018.
2. The Power Purchase Agreement (PPA) is valid till 2029. However, the agreement shall automatically consider expired in case GSA didn't extend after 20 years.
3. GSA expired in September 2019 and gas supply to plant stopped accordingly.
4. Amendment in the PPA and Settlement Agreement approved by CPPA-G board on May 03, 2021 and referred to Power Division for approval from Economic Coordination Committee (ECC) of the Federal Cabinet.
5. The Power Division finalized the summary and taken comments from all stakeholders. SSGC through Petroleum Division shared their consent for the supply of mixed natural gas (65% Indigenous gas & 35% RLNG) to HCPC.
6. The summary is awaiting ECC approval.
7. The Generation License of the HCPC is also valid till 2029
8. NPCC-NTDC shared the importance of HCPC to Quetta grid through various letters to CPPA-G & Power Division. The CPPA-G board approved the PPA Amendment based on the NPCC-NTDC letters.
9. NEPRA through their letter dated 20th August 2020 to NTDC also explained the significance of HCPC to Quetta grid.
10. Recent floods in Balochistan resulted in complete power outage in and around Quetta city. No alternate source of electricity supply available in Quetta to restore power to city. In such scenarios, HCPC plant is the only reliable power source for the city.
11. No alternate options shared by NTDC in IGCEP for the supply of electricity to Quetta.
12. Under normal circumstances and without HCPC; Quetta city is experiencing extended hours of loadshedding and low voltage issues. HCPC at the tail end of the grid is the only solution to provide reactive power in the system and resolve low voltage issues being faced in the city.
13. The electricity cost from HCPC is more competitive than importing electricity from other sources having a distance of more than 400KM.
14. The Capacity Payment of HCPC for the remaining term of the PPA already reduced due to expiry of Non Escalable component in the tariff after 20 years

Annex-III (10)

LAHORE ELECTRIC SUPPLY COMPANY LIMITED

DIRECTORATE GENERAL MIRAD LESCO HQ
near 132 kV Garden Town grid station, Ferozpur Road, Lahore
Ph: 042-99232117
www.lesco.gov.pk

SUB: **DRAFT IGCEP 2022-31 PREPARED BY NTDC**

REF: NEPRA' advertisement published on 27.09.22

Please find below the preliminary comments on subject draft:-

S.#	Section no.	Comments
1	3.6.4	Capacity factors of 22.1% & 20% have been considered for utility solar PV & feeder based solar respectively. Whereas in NEPRA' Market Commercial Code, equivalent availability factor of solar PV is mentioned as 0.22
2	4.4.1	Since medium term load forecast base year 2021-22 is under process, so the same should be incorporated.
3	5.2 (19)	What is the rationale for considering 480 MW net metering every year?
4	5.2 (30)	NEPRA vide Determination no.7064-71 dated 08.09.22 has approved renewal in Generation Licence no.IPGL/020/2004 in respect of KAPCO, upto 21.09.24.
5	6.8	What about Prime Minister's recently announced initiative of addition of 10,000 MW solar, led by AEDB?
6	**General**	
i	Revision of Grid Code is not yet approved by NEPRA	
ii	Whole scale revision of Distribution Code by NEPRA, to accommodate the integration of renewable energy sources / distributed generation etc., is requested	
iii	Power Procurement Regulation is not yet approved by NEPRA	
iv	National Electricity Plan is not yet approved	
v	Authority has not yet specified the procedures and standards for power acquisition program, as mentioned in clause 32 of NEPRA (amended) Act	
vi	We expect that input from Punjab Power Development Board (PPDB) has been taken by NTDC about small hydel.	
vii	What about impact of EV charging?	
viii	What about impact of captive power plants of industries?	
ix	What about impact of CPPs & SPPs granted licences by NEPRA under second tier supply authorization?	
x	What about impact of solar PV generation companies granted licences by NEPRA?	
xi	Couldn't find about biogas / waste to thermal based generation	
xii	Power procured / committed at Central level is already surplus.	

xiii	Since the distribution network was originally not designed, planned, constructed & operated with distributed generation' (DG) aspects in mind, so there should be support to DISCOs in addressing the potential technical issues resulting due to DG system' impacts (e.g. stability, power quality, protection, safety etc.)
xiv	Sites for proposed plants on 11 kV shall be close to existing distribution network
xv	System studies (i.e. load flow, short circuit, dynamic stability, harmonics etc.) shall be performed for the integration of each of proposed plants with distribution network
xvi	Induction of power generation should be on least cost principle
xvii	No procurement shall be on take or pay basis

Director General (MIRAD)
LESCO

To:

Registrar,
NEPRA
Islamabad

Copy:

1. Technical Director LESCO
2. Operation Director LESCO
3. Chief Law Officer LESCO
4. S.O to C.E.O LESCO
5. Master file

No. 8312-16 /CM Dated 17-10-2022

Noor Saleem

From: Imtiaz Hussain Baloch <ihussain@nepra.org.pk>
Sent: Tuesday, 25 October 2022 1:24 pm
To: Noor Saleem Khan (Addl. Dir-LIC); 'noorsaleem khan'
Cc: 'Hassan Raza Gillani'; '"Hassan Raza Gillani (DD-LIC)"'@mail.nepra.org.pk; Ahmad Usman Khan-AD(Licensing)
Subject: FW: DRAFT IGCEP 2022-31 PREPARED BY NTDC

From: Registrar [mailto:registrar@nepra.org.pk]
Sent: Tuesday, October 25, 2022 11:48 AM
To: Imtiaz Hussain Baloch <ihussain@nepra.org.pk>; Gul Hassan Bhutto <bhutto.gulhassan@nepra.org.pk>
Subject: FW: DRAFT IGCEP 2022-31 PREPARED BY NTDC

From: DG MIRAD LESCO [mailto:dgmiradlesco@gmail.com]
Sent: Tuesday, October 18, 2022 3:03 PM
To: registrar@nepra.org.pk
Cc: so@lesco.gov.pk; gmo@lesco.gov.pk; dirtech@lesco.gov.pk; legaldir@lesco.gov.pk
Subject: DRAFT IGCEP 2022-31 PREPARED BY NTDC

In continuation of this office email dated 17.10.2022, please find below further comments:-

Sr#	Comments
i	Reference to "Detailed design and implementation roadmap of CTBCM" approved by NEPRA in Nov 2020 and NEPRA' determination vide letter dated 31.05.22 regarding grant of Market Operator Licence and Market Commercial Code are missing here, which are among the main driver for the new regime.
ii	Link between IGCEP and CTBCM appears to be missing.
iii	What about requirement of competitive electricity market (i.e. target BPCs having 16% share in energy sales) after market liberalization? It appears that it has not been accounted for.
iv	Is IGCEP covering the power generation which will be sold / purchased via bilateral contracts under CTBCM by competitive suppliers and BPCs OR otherwise?

--
Best Regards & Thanks,

Director General (MIRAD)
Lahore Electric Supply Company (LESCO)
Near 132-KV Garden Town Grid Station, Kalma Chowk,
Main Ferozpur Road, Lahore
Ph: 042-99232117, 042-99232118 (Direct)
Email: dgmiradlesco@gmail.com, **Website:** www.lesco.gov.pk

Annex-I

DRAFT VIEWS/COMMENTS OF GOVERNMENT OF KHYBER PAKHTUNKHWA ON IGEP 2022-31

NEPRA has sought comments on the draft IGCEP 2022-31 through a notice published in national newspapers on September 27, 2022. GoKP has reviewed the initial draft of the IGCEP 2022 and appreciate the efforts made by NEPRA and NTDC while developing a handy document wherein certain projects of GoKP (both public and private) have found the space.

For the IGCEP 2022-31, GoKP shared total of 24 Private Sector Projects with combined capacity of 1888.3 MW, out of which 7 projects with combined capacity of 905.43 MW have been included in the draft IGCEP 2022-31. However, GoKP would like to put forward the following submissions for consideration by the Authority;

i. As IGCEP do not considers the projects less than 20 MW capacity which is creating ambiguity amongst the private sector investors who has spent ample resources both financial and technical. GoKP proposes that there shall be set mechanism in IGCEP for the projects less than 20 MW, keeping under consideration the huge quantum of projects, hence, a dedicated block coverage may be created so that these projects could get space in order to tape the indigenous resources of the province.

ii. Amongst the potential projects of GoKP, the 470 MW Lower Spat Gah HPP (LSG) has got immense importance, being the first ever initiative taken by the Provincial Government (GoKP) under the PPP arrangement with the Korean company M/S KHNP. The feasibility study has been conducted by the renowned consultant M/S AFRY which has been approved by PEDO Panel of Experts (PoE). The Company provided the raw data available at the time of the IGCEP 2022 proforma in December 2021. Since then, the functional specifications of the Lower Spat Gah HPP have changed following the input from PoE and further optimization by AFRY. The table below demonstrates the comparative specifications of the LSG, as provided in IGCEP proforma and approved by the POE.

Category	IGCEP-2022 Draft	PoE Approved
Annual Energy (GWh)	1,898	1,925
Economic Life (Years)	30	50

Category	IGCEP-2022 Draft	PoE Approved
Project Cost (M USD)	1,131	1,085
Capacity (MW)	496	470

iii. The annual energy, cost and economic life have enhanced in the approved feasibility study of the LSG, proving improved economic and financial feasibility. We are convinced that if the verified results of the LSG are reflected in the IGCEP classification, the project could be included in the Optimized Projects list.

iv. Furthermore, the 102 MW Shigo Kas HPP was brought into the advance stage while carrying out 1st ever tariff based International Competitive Bidding (ICB) with a competitive tariff of around 8.28 cents/kWh like 99 MW Arkari Gol HPP, duly approved by NEPRA, hence, it is requested that NTDC may also include the Shigo Kas HPP.

v. Furthermore, five Solar PV Projects with a cumulative capacity of 249.5 MW to be set up in KP with a levelized tariff of 3.5-3.9 cents/kWh (approved by NEPRA in 2020) may also be included in the IGCEP 2022, keeping in view the enhanced space in new iteration of IGCEP.

vi. It is worth mentioning here that NEPRA while approving the IGCEP-2021 on September 24, 2021, given the certain suggestions to NTDC for inclusion of the 470 MW Lower Spat Gah HPP, 102 MW Shigo Kas HPP and five Solar PV Projects in the IGCEP 22-31, but not included. The NTDC is requested to accommodate these projects, already recommended by the Authority.

vii. It is also notable that around 10,000 MW of candidate renewable projects block was allocated in IGCEP 2021-30 wherein it was anticipated that 1st round of the competitive bidding would be carried out which have still not been materialized for 2 years, then how the 12,000 MW candidate renewables as proposed in the current IGCEP will be procured. It is therefore requested that the Authority may look into the matter and have a proper roadmap for the purpose. Foregoing in view, the injection of these solar plants will result intermittency in the national grid. NTDC should show us the facts/figures that how the intermittency will be mitigated and its related financial impact.

viii. Also, it is proposed that a clear exception be provided in the new generation policy for those projects who have valid LOIs and are achieving the milestones on time. This exception can be given on similar basis as was provided in recent Income Tax Ordinance where income tax exemption will remain effective for those projects which have valid LOS up to June 2023. Similarly, Power Generation Policy 2015 will remain applicable to those projects which have valid LOI and will receive LOS before June 2023.

ix. Government of Khyber Pakhtunkhwa has mainly got the projects which are small and medium size capacity run of the river, including these projects in IGCEP will not have a major impact on the overall target capacity. Hence, these may be given due consideration in future since IGCEP is a live document which will be updated on yearly basis. Furthermore, these projects located in far flung areas will produce local electrons which can be utilized locally and will result in lower line losses. The list of potential projects is given below.

S #	Project Name	District	Capacity (MW)	Expected COD
(A)	**Public Private Partnership (PPP) Mode G2G Hydropower Projects**			
1	Lower Spatgah HPP	Lower Kohistan	470	June, 2030
	Total		**470**	
(B)	**Private Sector Hydropower Projects - IPPs**			
2	Shigo Kas HPP	Lower Dir	102	July, 2027
3	Gabral Utror HPP	Swat	82	Oct, 2027
4	Artistic-1 HPP	Upper Dir	62.61	Aug, 2027
5	Shalfalam HPP	Upper Dir	60	Dec, 2028
6	Artistic-2 HPP	Swat	55.03	Jun, 2027
7	Kaigah-II HPP	Kohistan	39.6	Jun, 2029
8	Bankhwar HPP	Swat	35	Oct, 2028
9	Trappi HPP	Mansehra	32	Jun, 2029
10	Tangar HPP	Mansehra	25.91	Jun, 2028
11	Kaigah-III HPP	Kohistan	21	July, 2029
12	Bela (Gwaldai Sin) HPP	Upper Dir	20.4	Aug, 2027
13	Nandihar-II	Battagram	10.97	Dec, 2028
14	Mahandri HPP	Mansehra	10.40	Jun, 2028
15	Daral Khwar-II HPP	Swat	9.5	Jun, 2028
16	Balkani HPP	Shangla	7.75	July, 2028
17	Serai Sin HPP	Upper Dir	6.9	Nov, 2028
18	Machai III HPP (MBC-17 & 18)	Mardan	1.72	July, 2026
	Total		**582.89**	
	Grand Total (Hydro Projects)		**1052.89**	
(C)	**Private Sector Solar PV Projects**			
1	Kulachi, DI Khan	DI Khan	50	Mar, 2023
2	Kulachi, DI Khan	DI Khan	50	Sep, 2023
3	Paharpur, DI Khan	DI Khan	49.5	Sep, 2023
4	Nowshehra	Nowshehra	50	Jan, 2025
5	Kohat	Kohat	50	Jan, 2025
	Total (Solar Projects)		**249.5**	

PEDO

PAKHTUNKHWA ENERGY DEVELOPMENT ORGANIZATION

Government of Khyber Pakhtunkhwa Peshawar

PEDO House, 38/B-2, Phase-V, Hayatabad, Peshawar. Tel: (+92-91) 9217246, Fax (+92-91) 9217003

No. 2081-83 /PEDO/D (P&F)/NEPRA
Dated: October 18, 2022

Fw ufo gn. e R 19/x/22
- DG (Lic)
copy t
- ADG (T)
- SA (M&E)
- Cns (Tech)
- m.f
cc Chairman
- M (M&E/CA)
- M (Lic/T)

To

Mr. Shakil Ahmed
Additional Director (Registrar Office)
National Electric Power Regulatory Authority (NEPRA)
NEPRA Tower, Ataturk Avenue (East), G-5/1, Islamabad

Subject: **NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-31 (IGCEP-2022)**

This is with reference to your letter No. NEPRA/DG(Lic)/LAT-01/18675-33 dated September 27, 2022, wherein the Authority has directed all stakeholders to submit their comments on the draft IGCEP 2022-31 for the upcoming public hearing to be held on October 19, 2022.

2. In this regard, GoKP/PEDO has reviewed the draft IGCEP 2022-31 and appreciate the same, however, we would like to put forward some additional comments/views for consideration of the Authority (Annex-II) in continuation of this office letter No. PEDO/CEO/DREPP/NEPRA/8972-74 dated October 18, 2022 in respect of below PEDO, Public Sector Projects less than 20 MW capacity and not been considered as a committed projects in IGCEP 2022-31; however the same projects were included is committed projects in IGCEP 2021-30.

i. 11.8 MW Karora HPP
ii. 10.2 MW Jabori HPP
iii. 10.56 MW Chapare Charkhel HPP

Director (P&F)
PEDO, Peshawar

REGISTRAR OFFICE
Diary No: 10911
Date: 19-10-2022

Copy for information to:

1. CEO PEDO, Peshawar
2. Chief Engineer Dev, PEDO, Peshawar

Director (P&F)
PEDO, Peshawar

GoKP comments on IGCEP 2022-31 regarding PEDO Public Sector Projects

S.No.	Name of Project	Views/Comments
1.	11.8 MW Karora HPP District Shangla	PEDO is implementing 11.8 MW Karora HPP under Public sector mode in District Shangla. The Project was included in IGCEP 2021-30 in the category of "**Committed Project**" however in the current draft IGCEP 2022-31 it has been dropped on the pretext of its capacity less than 20 MW which is creating ambiguity. We presume that as mentioned in the previous IGCEP 2021, it is still a committed project but clarity/ confirmation on the same is requested. The project is 95% completed and tentative COD date is February 28, 2023. The project will be connected to the National Grid.
2	10.2 MW Jabori HPP District Mansehra	The 10.2 MW Jabori HPP was included as committed project in IGCEP 2021-30 for December 2021. NTDC while preparing the new IGCEP 2022 asked for the COD date which was communicated as March 2022 but in the draft IGCEP 2022, the same has not been mentioned in the list of committed projects. We presume that as mentioned in the previous IGCEP 2021, it is still a committed project but clarity / confirmation on the same is requested please.
3	10.56 MW Chapare Charkhil HPP, Kurram	PEDO is implementing 10.56 MW Chapri Charkhel HPP under Public sector mode in newly merged District Kurram. The Project was included in IGCEP 2021-30 in the category "Committed Project" however in the current draft IGCEP 2022-31 it has been dropped on the pretext of its capacity less than 20 MW which is creating ambiguity. We presume that as mentioned in the previous IGCEP 2021, it is still a committed project but clarity/ confirmation on the same is requested. The project is in pre-construction phase and the commencement of physical construction is expected in February 2023 and the expected completion is June, 2026.

SIDDIQSONS
L I M I T E D

Fw u/o 8n. ERP 12/x/22
- DG (Lic)
copy to
- ADG (G)
- SC (MEE)
- Ems. (Tech)
- Ems. (CTBCM)
- m .F

cc Chairman
- m (MEE/CH)
- m (Lic/T)

Ref: SEL/Coal/221011 Date: 11/10/2022

REGISTRAR OFFICE
Diary No: 10602
Date: 12-10-2022

Registrar,
National Electric Power Regulatory Authority (NEPRA)
NEPRA Tower, Attaturk Avenue (East), G-5/1,
Islamabad.

Subject: Comments on IGCEP 2022-2031

We are writing with reference to the Indicative Generation Capacity Expansion Plan 2022-2031 ("IGCEP") issued by the National Transmission and Dispatch Company ("NTDC") and NEPRA's notice for seeking of comments on IGCEP (the "NEPRA Notice").

Siddiqsons has a portfolio of 104.5 MW of hydro project in AJK and KPK region i.e Jagran-III(35 MW), Shalfalam Hydro (60MW) and Daral Khwar-II (9.5MW) at various stages of development.

With regards to the IGCEP linked to these projects we hereby submit the following comments/concerns which shall be duly considered by NEPRA and incorporated for approval:

1. Out of total 46 Candidate Hydro Power Projects, 23 of the projects' Capital Cost have been revised to a lower number whereas it is the opposite for 60MW Shalfalam and 35 MW Jagran-III HPPs
2. **Shalfalam** HPP Capital Cost submitted in the IGCEP Data Performa was $170.18 Mil. which has been increased to $184.3 Mil (an increase of 8.3%) without our consent and knowledge
    a. With $170.18 Mil. our tariff comes out to be 4.9 ¢/kwh (approved feasibility)
    b. With the original tariff of 4.9 ¢/kwh submitted in the feasibility, we feel we would have been in the list of the selected HPPs till 2031
    c. The cost should be corrected to the submitted Capital Cost of $170.18 million corresponding tariff of 4.9 ¢/kwh
3. **Jagran-III** total project cost has been indexed from $125.6 Mil. to $130.3 Mil. (an increase of 3.7%). The Capital Cost in the current iteration of IGCEP is of feasibility stage number which were later revised to $104.2 at EPC stage tariff submitted to CPPA and NEPRA (copied) in October 2018
4. **Daral Khwar-II (9.5MW)**, approved by PEDO on 29th June 2022 has not been included in the list of candidate HPPs. A clarity is required on the prospect of small hydro projects on which we have spent time and money to make it viable
5. We fail to comprehend the indexation mechanism in the IGCEP tariff as there is no backing of this indexation in the report

With all the above comments, it is evident that IGCEP has conveniently overlooked projects that are at advanced stages of development, particularly those projects for which considerable resources and investment have already been utilised by the respective sponsors/investors.

27th Floor, Ocean Tower, G-3, Block - 9, KDA Scheme No. 5, Main Clifton Road Karachi.
Tel No. +92-21-35166571-5 & 35166521-4 Fax No. +92-21-35166527 Email: contact@siddiqsons.com Web: www.thesiddiqsonsgroup.com
Factory: D-53, Textile Avenue, S.I.T.E, Karachi, Pakistan. Tel No. +92-2132577483-4
Plot No. 14/1M, Hite, Dist. Lasbella Baluchistan. Tel No. 0853-363016

For example, in the case of **Jagran-III**, the project has achieved the following milestones:

- Environmental Studies have been conducted and approved;
- Grid Interconnection Studies have been conducted and approved;
- Power evacuation certificate has been issued by NTDC;
- Engineering, Procurement and Construction Contract has been finalised;
- Geotechnical and Topographic studies have been conducted;
- Engaged renowned German consultants for designing of plant;
- Land acquisition notification under Section 4 of the Land Acquisition Act has been notified by the relevant government department;
- Private Power Cell of Government of AJK to the PPIB has issued consent for processing of Tripartite LOS
- EPC stage tariff submitted to CPPA for onward submission to NEPRA in Dec 2017
- EPC tariff submitted directly to NEPRA in Oct 2018

Shalfalam 60MW

- Feasibility approved by PEDO
- Site visit and land demarcated
- EPA report submitted; NOC awaited
- Cost-plus tariff formulated, to be submitted soon

9.5 MW Daral Khwar-II, KPK

- Feasibility approved by PEDO
- IEE submitted to EPA KPK for their approval
- Cost-plus tariff formulated, to be submitted soon

Above milestones and achievements are testament to Siddiqsons' commitment towards development of Hydro Projects. After receiving LOIs from relevant agencies we have invested over $8 million in the development of these projects

We strongly recommend that these low-cost hydro projects should be included in the latest iteration of IGCEP for approval and implementation of projects by or before 2029. We would also like to meet with your team to further seek clarity and give our inputs on this IGCEP

Regards

Muhammad Vakil

Abdul Vakil
Chief Operating Officer

C.C:

Mr. Engr. Dr. Rana Abdul Jabbar Khan, Managing Director, NTDC

Mr. Safdar Hayat, Deputy Director, Peshawar Energy Development Organization

Director General, Private Power Cell (PPC,AJK Muzaffarabad)

Annex-III (13)

ARTISTIC MILLINERS (PVT) LTD.

MANUFACTURERS & EXPORTERS OF YARN, DENIM FABRIC & FASHION GARMENTS
Plot No. 4 & 5, Sector 25, Korangi Industrial Area, Karachi-74900 Pakistan.
GST # 17 - 00-5205-002-82, NTN # 2645727-0
Tel: (0221) 35072586-88, 35075337-39 Fax: (0221) 35076446 Email: artistic@cyber.net.pk, corporate@artisticmilliners.com

Ref: AM/KPK/HPP/008-17/22
Date: 17 Oct 2022

REGISTRAR OFFICE
Diary No. 10585
Date: 18-10-22

The Registrar
National Electric Power Regulatory Authority,
NEPRA Tower, Ataturk Avenue (East)
G-5/1, Islamabad

For necessary action
DG (Lic)
C-PYL
-PDG (LT)
-Cms (Tech)
-SA (LIZE)
-Cms (CTBCM)
DG (Tariff)
-C (LIC/LG)
-C (LIC/T)

Subject: Comments of Artistic Milliners (Pvt.) Ltd in the Matter of Indicative Generation Capacity Expansion Plan 2022-31 (IGCEP)

Dear Sir,

In compliance with the provision (PC-4 and PC-4.1) of the Planning Code of the Grid Code, National Transmission and Dispatch Company Limited (NTDC) has prepared the IGCEP and submitted it for review and approval of the Authority (NEPRA).

In this regard, Artistic Milliners (Pvt.) Ltd (AMPL) is submitting our comments on the IGCEP.

- Considering section 5.8.2 of the National Electricity Policy (NEP) which requires that the National Grid Company (NGC) shall submit the Rolling Transmission System Expansion Plan (TSEP) under the Grid Code in support of the IGCEP to the Regulator for approval. In the absence of such a Plan, how are the projects considered to be selected on a least-cost basis. This entails especially in the case of 55 MW Artistic Hydro II which requires only an Eight (8) km transmission line for the evacuation of power. This is a total waste of key national resources by not giving space to such a promising hydro site.

- Section 5.5.1 of the NEP stipulates that the expansion in generation capacity shall be only on a competitive and least cost basis (except for strategic projects), this principle has not applied to the selection of Artistic Hydro II as its annualized cost of energy determined under the IGCEP already lower than the multiple hydro sites which have been PICKED. What additional criteria/assumptions are used in the IGCEP for the selection of high cost hydro projects. These assumptions should be clearly spelled out in the IGCEP for a better understanding of all the stakeholders.

Manufacturing Locations:
Plot No. 4 F-2/2, Deh Landhi, Bin Qasim Town, Karachi
Plot No. 5 Sector 25, Korangi Industrial Area, Karachi-74900
Plot No. 4, Sector 25 Korangi Industrial Area, Karachi-74900
Plot No. 39,11,14,15 & 104, Deh Khanto Upper Landhi Bin Qasim Town, Karachi.
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Tel: 92213-5072586-8 Fax: 35076446

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GST # 17 - 50 5205 002 82, NTN # 2645727-0
Tel: (9221) 35072686-88, 35075337-39 Fax: (9221) 35075446 [illegible]

- The technology of hydro sites is quite similar but different economic life (30 to 100 years) has been used for different candidate hydropower projects. There is a concession period of thirty years available to the Projects and subsequently, projects would be transferred to the Govt. NTDC should either consider the economic life of all these candidate hydro sites as thirty years or if the longer economic life given by the Projects, then all projects of the same technology (i.e., hydro) should be evaluated at the same long economic life as Projects after the expiry of concession period would no longer be responsible for their long economic life claims. Similarly, for any other obvious inconsistency noted by NTDC at the time of data validation then they should fix those with the Projects prior to using the same in IGCEP as such a limited natural resource can be highly jeopardized due to lack of understanding by Projects at the time of filling project data for IGCEP.

- Since most of these hydro sites are run off the river as cascade projects, in the absence of TSEP, criteria used by NTDC to select hydro sites might skip multiple projects which are coming on the same river cascade where cost allocation of a single transmission line for the entire corridor could make them highly feasible. The criticality of TSEP is so significant that it can make already selected hydro sites non-feasible and vice versa.

We will be obliged to the Authority to consider our grievances and direct NTDC to reevaluate Artistic Hydro II on its merit.

Sincerely yours,

For and on behalf of Artistic Milliners (Private) Limited

Rafique Khanani
Authorized Representative

HUBCO
Hub Power Holdings Ltd.

Hub Power Holdings Ltd
9th Floor, Ocean Tower
Block-9, Main Clifton Road
Karachi. Pakistan

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+92 21 3583 9018
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HPHL/HoBD/IGCEP/1002-1022

October 18, 2022

The Registrar
National Electric Power Regulatory Authority
NEPRA Tower, Ataturk Avenue (East)
G-5/1, Islamabad, Pakistan.

Subject: Comments on Indicative Generation Capacity Expansion Plan (IGCEP) 2022-2031

Dear Sir,

We write with reference to the IGCEP 2022-31 document published on September 20, 2022. We offer our congratulations to the National Transmission and Dispatch Company on providing a comprehensive and far-sighted document for our review that is well structured and includes scenarios that are critical for Pakistan's energy security. And we thank the Authority for facilitating comments and discussion on the IGCEP. This version of the IGCEP has certainly improved upon and addressed some limitations of the previous iterations of the document.

It is especially heartening that the IGCEP prioritizes the need to increase indigenous fuel and variable renewable energy to address the energy challenges facing the country. We consider the information contained in the IGCEP document to be very insightful and would like to bring forth a few observations and offer feedback, in the appended table, based on our internal due diligence, for your kind consideration.

We look forward to further engagement on this important document and contributing to the energy sector in Pakistan.

Sincerely,

Danish Khaliq
Head of Business Development
Hub Power Holding Company

Appendix - 1

Serial Number	Reference Clause	Observation	Comments and Questions
1.	Disclaimer, Clause: d, (Page iii):	IGCEP 2022-31 is exclusive of any costs related to the power system evacuation and transmission system expansion for optimized generation projects. This may have a crucial impact on generation planning as any variation in the optimized projects subject to T&D costs may affect the candidacy of the respective project in the list. Moreover, due to generalization of cost, the plan is not location optimized and assumes that all plants can be implemented on an equal basis.	Please clarify how more accurate costs of individual projects in the IGCEP can be sought.
2.	Section 1.6, (Page 13):	One of our observations is with regards to candidate projects' inclusion and exclusion in subsequent iterations of the IGCEP.	How does the IGCEP ensure that a candidate project is not excluded from subsequent iterations. This certainty is critical from the perspective of a developer to make an informed decision
3.	Section 3.2 & 3.3 (Page 27):	Data used to develop the IGCEP	We request that the data files from which the tables and charts are derived be provided in a publicly accessible database in MS Excel or equivalent format.
4.	Section 4 (Page 35):	We also observed that the document does not address access to electricity while computing demand projections, which is lower in Pakistan compared to India and Bangladesh.	If Pakistan is to meet 100% electricity access (currently ~70%) targets as envisioned in the UN Sustainable Development Goal of universal electricity access, the demand projections may change significantly, and may need to be revisited.
5.	Section 4.6, (Page 40):	The demand projections are based on computed peak demand and not on recorded peak demand. This may not be entirely accurate as it is the maximum sum of recorded peak demand and load management of each respective hour. Similarly, in the	The demand projections may need to be revisited, based on the recorded peak demand.

Serial Number	Reference Clause	Observation	Comments and Questions
		current year the load management due to various reasons had reached over 7 GW.	
6.	Section 5.2, Clause: 19 (Page 49):	Keeping in view the issuance of just over 200 MW licenses for net-metering in FY 2021-22 (State of the Industry Report 2022), targets of 480 appear to be aggressive. Additionally, recent regulations to reduce the grid-feed price may have an impact on the annual targets as well.	Given current adoption rates of Net Metering and latest regulations policy changes, could further elaborations be provided to as to how this target of 480 MWp is to be achieved? Moreover, clarity on Net Metering targets across the different scenarios is also requested.
7.	Section 5.10 (Page 58):	Solar PV (Block of ≤ 150 MWp); reference cost and parameters – as provided by AEDB, subject to approval by NEPRA	Has the 350 MW KE solar project been included in the plan? When is the anticipated capacity addition?
8.	Section 5.2 Clause 33c. (Page 47), Table 6-1 (Page 67) and Figure 6-1 (Page 68):	While we understand that the IGCEP is VRE focused, with Hydro and RE leading future capacity addition, candidate hydro power projects have only been considered 2029 onwards. Considering the life of hydro power projects as well as the capacity factors offered, we believe that equitable participation of candidate hydropower projects through the planning horizon of the IGCEP may offer early energy security as well as grid stability.	Consideration for equitable participation of hydro power projects for the IGCEP timeline requested.
9.	Section 5.10 (Page 57) & Table 6-1 (Page 67):	It is observed that candidate wind projects worth 2.9 GW will be absorbed in the NTDC system within a span of one year in 2028. The IGCEP does not directly mention the sizes or the locations of the individual candidate projects that will be coming online within the year.	Please provide clarity on how these projects would be added in the system and what would be the sizes and locations of these individual projects.

Serial Number	Reference Clause	Observation	Comments and Questions
10.	Table 6-1 (Page 67) and Figure 6-1 (Page 68):	G2G projects and Category III projects have not been identified separately.	How would the concentration of candidate solar projects from 2025 up till 2027 affect the Category III projects which are already in line and awaiting competitive bidding?
11.	Table 6-1 (Page 67):	Optimized Generation Capacity Additions for KE	Have the 3 x 50 MW solar projects been included in the plan for KE?
12.	Table 6-1 (Page 67):	Waste to Energy projects have not been considered as candidate projects in this iteration.	Given the significance of utilizing municipal solid waste in large cities such as Karachi and Lahore, as well as the issuance of upfront tariff by NEPRA, it is requested that the respective technology be included in the upcoming iterations of IGCEP.
13.	Table 6-3 (Page 72):	It has been observed that the nature of the future coal projects has not been identified.	Based on the information provided, could it be clarified whether any coal conversion projects have been envisioned throughout the IGCEP horizon. Moreover, the nature of "KE_New_Local Coal" Project is not clear, as to whether it is a retrofit of an existing project, or a new project being considered.
14.	Annexure B, Table B-1, (i). and (ii). (Page 113)	In NEPRA's State of the Industry Report (SOTIR) for the year 2022, the installed capacity for NTDC + KE as of June 2022 was 43,775 MW (page 45 of NEPRA's State of the Industry	Please provide clarity on the discrepancy in the data.

Serial Number	Reference Clause	Observation	Comments and Questions
		Report 2022). However, in IGCEP the installed capacity is 41,268 MW (Page 113). This seems to be caused by differences in reported figures for individual plants. For example: • SOTIR has Sapphire wind as 53 MW but IGCEP has it as 50MW, • SOTIR has Metro wind 2 as 50 MW but IGCEP has it as 60 MW. • SOTIR reports total Solar capacity as 530 MW, but does not include Gharo and Ourson in KE Solar Projects (50 MW each). However it does include AJ Power and Harappa solar (30 MW combined), leading to a net difference of 70MW with IGCEP's reported count for solar (600MW).	
15.	Annexure-B-6 (Page 127):	Certain hydro projects like Shigo Kas have not been picked for inclusion in candidate projects in any of the scenarios although other projects with similar project costs and tariffs have made the list.	Are there other factors under consideration for inclusion of candidate projects?
16.	Executive Summary (Page 3) and Chart 6-9 (Page 87); Section 5.10 - e. ii – (Page 57) and Annexure G-3 (Page 197)	We found slight discrepancies in the report. For instance, the percentage of hydropower share in 2031 is mentioned as 41% in the Executive Summary whereas Chart 6-9 indicates 39% total participation by generation. Similarly, Annexure G-3 shows a total of 1,577 MWp Solar Feeder projects to be added from 2024-2026. This included with 500 MW in 2023 crosses	The variation in the main body document and the annexure tables/charts may be revisited for sanctity of the data.

Serial Number	Reference Clause	Observation	Comments and Questions
		the target of 2000 MW as indicated in section 5.10. Some variations in summation have also been noted in various tables of the IGCEP document.	
17.	Demand Side Management (Section 4.4.1 Page 37)	NEECA efficiency targets have been mentioned along with Rationalization by NTDC.	Please provide more details on energy efficiency programs and assumptions to achieve DSM targets.

1

NEELUM GREEN ENERGY (Pvt.) Ltd.

Date: 04 October 2022
Ref: NGE/OCT/04/10/2022

To:

Honorable Chairman NEPRA
Mr. Tauseef H. Farooqi
NEPRA Headquarters
Islamabad

Registrar
DG (Lic)
11/10/2022.

Subject: **COMMENTS ON IGCEP 2022**

Respected Chairman,

With regards to above mentioned subject, I would hereby like to state that as we all are aware, hydro projects are universally known for high capital costs but are economically far more beneficial over the project's life.

With regards to myself, I am the CEO of Neelum Green Energy Pvt. Ltd, a company which was awarded a 49MW hydropower project named Luat in Neelum Valley, AJK back in 2015.

Since being awarded this project by the Private Power Cell (PPC) AJK a number of milestones have been achieved from our end which include:

- Environmental NOC issued by EPA, AJK
- Grid interconnection study which has been approved by NTDC
- Finalisation of EPC contractor after carrying out ICB by the company
- Arrangements for financing of the project
- Land acquisition through local government via implementation of section 4.

REGISTRAR OFFICE
Diary No. 10554
Date: 11/10/22

Other highlights of Luat HPP for its priority inclusion are as under;

- Replacement of fossil fuel based generating units with hydro plants would cut down our reliance on volatile oil and gas markets.
- Location of Luat HPP is particularly favorable due to short and less costly power evacuation infrastructure.
- Availability of full installed capacity in the early spring that could supplement the National Grid capacity at a most critical time.
- Major contribution in summers towards energy mix when the system load in the major load centres spikes.

CHAIRMAN
Dy No. 6983
Date: 06-10-2022

Fw n/a
- DG (Lic)
copy to
- DG (CT)
- SA (MEE)
Cons. (Tech)

11/x/22
cc Chairman
- m (MEE/CA)
- m (Lic/T)

1ST Floor, 2-D, I & T Centre, Khayaban-e-Sorwardi Sector G-6/-1-1, Aabpara, Islamabad
Ph: 051-4861790, email: info@neelumgreenenergy.com

NEELUM GREEN ENERGY (Pvt.) Ltd.

The above considerations relate to the obvious economic benefits of Luat HPP that cannot be overlooked.

I would also like to highlight the fact that the cost of our project mentioned in the draft of IGCEP 2022 isn't the cost we offered.

Another important fact to be noted is that the list of projects included in early harvesting IGCEP, some sites are remotely located requiring longer and expensive transmission's infrastructure.

The list also includes some projects for which arranging funds within scheduled time would not be easy.

It is therefore hoped that NTDC would review the IGCEP on factual grounds and include Luat HPP in its priority plan.

Hoping for your continued support and considerations.

Mohsin Bilal
CEO
Neelum Green Energy Pvt. Ltd

Annex-III (16)

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Doc. Name	Response to IGCEP 2022-31		
Doc. ID	DEAA00018123	Revision	
Doc. Type	Correspondence	Pages	1 (8)
Author	Akram, Arif - Energy Business	Status	
Reviewed by Approved by	- -		

October 19, 2022

National Electric Power Regulatory Authority

Islamabad, Pakistan

Subject: **Response to the Indicative Generation Capacity Expansion Plan (IGCEP) 2022-31**

Dear Sirs,

We would like to express our appreciation to NTDC for preparing a comprehensive report on "Indicative Generation Capacity Expansion Plan (IGCEP) 2022-31", and to NEPRA for providing the opportunity for the stakeholders to share their feedback on the report. It is an instrumental compilation based on a scientific approach and methodology. The experts behind the IGCEP 2022-31 report have done an extensive job of applying rigorous modelling and optimization exercises based on data and assumptions from various trusted sources while considering the existing and future generation power projects, policy frameworks, commercial obligations, and natural resource allocations.

We have noticed several major updates and improvements in the IGCEP 2022-31 compared to the previous versions. These include the expansion in coverage to model to the K-Electric system, the additional scenarios to see the impact of different technologies, and the modelling of net metering targets, to name a few.

Nevertheless, as the IGCEP report states, "there is no room bigger than the room for improvement" (section 6.9., page 90) Wärtsilä welcomes the opportunity to comment on the latest IGCEP, and would like to contribute our expertise to design the best IGCEP with NTDC, NEPRA and other stakeholders in Pakistan.

Wärtsilä is a global leader in sustainable technologies and complete lifecycle solutions for the marine and energy markets. The company operates in over 200 locations, in more than 70 countries.

Wärtsilä is a licensee of PLEXOS® and has modelled power systems in nearly 200 countries, regions, and systems. We have been working closely with customers and partners worldwide, supporting them with advanced power system modelling capability and an in-depth analysis of the energy industry. We have contributed to Power Development Plans in several countries and have encouraged the planners to design the most optimal future power systems with reductions in both total system costs and emissions.

We note that to develop an effective least-cost generation capacity expansion plan that will meet the country's power needs, both the strategic considerations and constraints faced by Pakistan's power sector are carefully considered. There is a strong emphasis on reducing the dependence on imported fuel, even while honouring the take-or-pay commitment on fuel intake for existing gas-power plants, till the year 2032. The need to exploit hydropower's full potential and maximize domestic coal use has been adequately stressed. Wärtsilä understands the significance of these considerations in the planning process.

To provide insightful comments on the IGCEP-22 report, we have carried out a PLEXOS® modelling for the Pakistani power system for the years 2022-2031, based on main inputs data and assumptions from the IGCEP-22 report and other public sources.

Wärtsilä would like to present the following perspective for your consideration:

1. Validate the long-term expansion study with a short-term model while using a higher level of detail

For the preparation of the IGCEP, PLEXOS® software has been utilized, in particular, the long-term (LT) expansion plan function of the tool (section 1.8., page 14). To optimize the power system, PLEXOS includes consideration of hourly projected electric power demand up to the year 2030-31 and various other characteristics such as hydrology of hydropower projects, fuel costs estimations, and all technical and financial data of existing and potential generation options, and optimization of all options (section 1.6., page 13).

While we fully support the use of PLEXOS as the leading optimization software in the industry and the scientific approach that has been followed in the IGCEP 2022-31, we would like to suggest further testing the feasibility of the results from PLEXOS long-term expansion model with another function of the software, which is the short-term (ST) modelling. In general, the ST model is used for more detailed modelling and to see how the system will dispatch in a smaller step size with a given capacity.

This validation step is even more critical with a system with a higher share of variable renewable sources. The base case of the IGCEP shows a major contribution from renewables, with 20% of variable renewable energy in the overall energy mix by the year 2031 (section 6.8, page 87). Since the long-term expansion model is run with a 1-hour resolution (below is a dispatch graph from IGCEP 2022-31, page 89), a big part of the variability of renewables output and the change in demand on a minute level will be grouped and smoothened out. Therefore, a short-term model with a 15-minute resolution or even a 5-minute one will provide a more accurate snapshot of the system in a given period and better showcase the feasibility of the suggested results from the PLEXOS® LT plan.

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Doc. Name	Response to IGCEP 2022-31		
Doc. ID	DEAA00018123	Revision	
Doc. Type	Correspondence	Pages	3 (8)
Author	Akram, Arif - Energy Business	Status	
Reviewed by Approved by	- -		

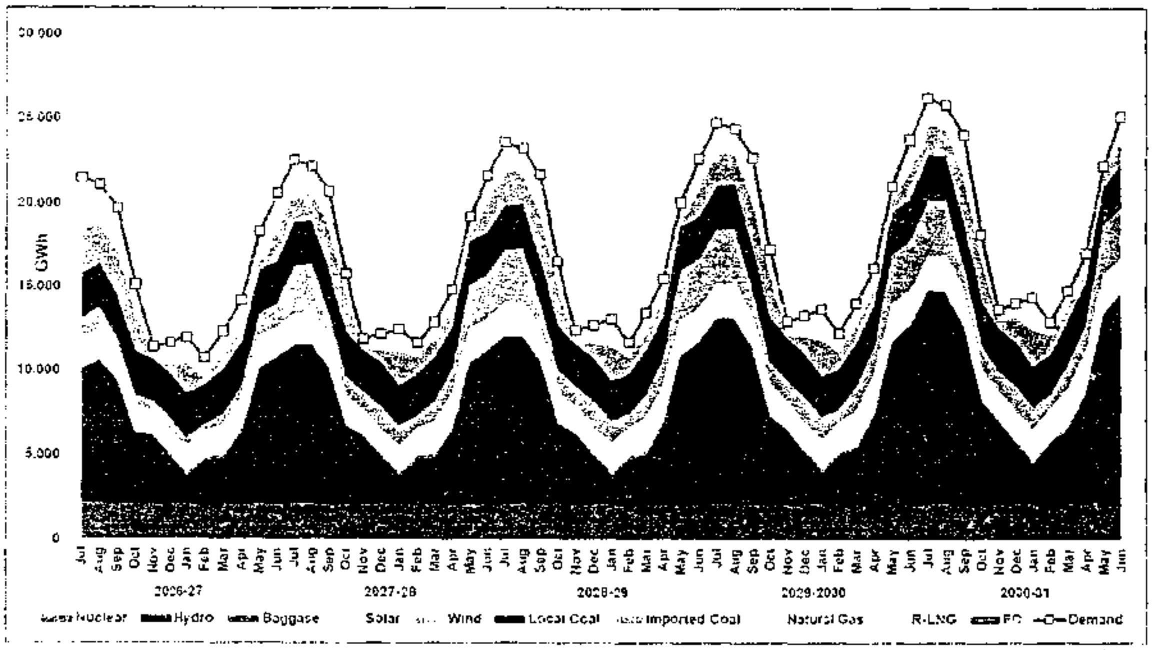


Chart 1: IGCEP Monthly generation mix 2027-31 (GWh)

The IEEE Electrification's Magazine has recently published an article (December 2021 issue) on the *Emerging Best Practices for Modelling Battery Storage in Integrated Resource Plans*[1]. The article compares the emerging modelling trends for 6 leading utilities in the US. Several utilities are pointing out the need for higher modelling resolution in order to properly determine the grid's real-life flexibility requirement.

"PGE used the Resource Optimization Model (ROM) as an external model for one-off analyses to inform other IRP models in the 2016 IRP, the 2019 plan fully integrated the ROM into the process, using it to calculate a flexibility value—a more detailed version of the operational value used in the 2016 IRP—for all resource options. The ROM calculated the flexibility value by modeling the system a week at a time with three levels of temporal resolution: hourly unit commitment on a day-ahead basis, followed by 15-min unit commitment on an hour-ahead basis, and concluding with 15-min real-time dispatch. By stepping through different levels of granularity, with unit commitments made in each period preserved in subsequent periods, PGE was able to drill down into its real-time ancillary service needs with high resolution and select the optimal resources to meet them."

2. Include more dynamic properties of power plants in the model

Variability and intermittency of renewable generation are one of the biggest challenges for the future power system. To capture the system inflexibility and the true thermal generation costs, the level of detail of wind and solar PV variability modelling should be high. The modelling should contain a full-year chronological profile with high granularity to capture the variable nature of wind and solar PV. This ensures that the model

[1] https://ieeexplore.ieee.org/document/9632850

sees days and weeks with high and low variable renewable energy (VRE) generation levels and their intra-daily variation.

To accommodate solar PV and wind generation variability, conventional power plants need a certain level of flexibility in operation. For the foreseeable future, existing thermal power plants will operate alongside renewable energy plants and will play an essential role in providing supply-side flexibility. As a result, it is essential to equip PLEXOS models with a complete range of technology options with well-defined flexibility characteristics.

The following parameters are crucial to demonstrate the flexibility of power plants:

- Ramp rate (both upward and downward) and ramp charge
- Part-load efficiency
- Minimum stable load
- Minimum uptime and downtime
- Start-up time and start-up costs

As an example, here is an extract from IRENA's report[2] on flexibility in power plants.

Table 1 Comparison of flexibility parameters before and after flexibilisation initiatives

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Hard coal	Average plant	3-10 h*	> 100	25-40%*	45%	40%	1.5-4%*	48 h	48 h
	Post flexibilisation	80 min-6 h*	> 100	10-20%*	45%	40%	3-6%*	8 h	8 h
Lignite	Average plant	4-10 h*	> 100	50-60%*	40%	35%	1-2%*	48 h	48 h
	Post flexibilisation	75 min-8 h*	> 100	10-40%*	40%	35%	2-6%	8 h	8 h
CCGT	Average plant	1-4 h*	55	40-50%	52-57%	47-51%	2-4%*	4 h	2 h
	Post flexibilisation initiatives	30 min-3 h*	55	20-40%	52-57%	47-51%	8-11%*	4 h	2 h
OCGT	Average plant	5-11 min	< 1-70	40-50%	35-39%	27-32%	9-12%	10-30 min	30-60 min
	Post flexibilisation/ advanced plant	5-10 min	< 1-70	20-50%	35-39%	27-32%	8-15%	10-30 min	30-60 min
ICE*	Average plant	5 min	< 1	30% (per unit)	45-47%	45-47%	> 100%	< 1 min	5 min
	Post flexibilisation/ advanced plant	2 min	< 1	10% (per unit)	45-47%	45-47%	> 100%	< 1 min	5 min

* Start-up times are longer for cold start-up (plant shut for more than 48 hours) than for hot start-up (plant shut for less than 8 hours).

Notes: h = hour; min = minute; MW = megawatt; Pnom = nominal power.

[2] IRENA (2019), Flexibility in Conventional Power Plants, International Renewable Energy Agency, Abu Dhabi. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019.pdf

3. Consider additional new-built technology candidate options, such as flexible multifuel engines, energy storage, or flexible demand

Continuing on the referenced need for dynamic parameters of power plants, our next recommendation is to consider other new-built candidate options with the possibility of providing flexibility to balance the grid. Coal-fired power plants, CCGTs, and nuclear power plants have been designed to provide baseload generation but were not designed to be ramped up or down at short notice.

The lack of flexibility in the system can also result in the curtailment of variable renewable generation and in inefficient operation of the conventional baseload power plants. This point has also been raised within the IGCEP report as a challenge that needs to be overcome to enhance the report content and modelling quality (section 7.2, pages 93-94).

Flexible technologies, such as flexible engines running on several types of fuels and battery energy storage systems, could help Pakistan take advantage of the low-cost renewable energy sources without being constrained by its intermittent nature. Flexible solutions are the enablers of renewable energy by managing variability and ensuring reliability. Pakistan can leapfrog into a future where total demand will be met by a combination of renewable energy and flexible backup generation.

Wärtsilä Energy offers a portfolio of ultra-flexible internal combustion engine power plants and utility-scale battery energy storage systems. As of 2021, Wärtsilä has 74 GW of installed power plant capacity in 180 countries worldwide. We have delivered more than 100 Battery Energy Storage systems with over 2 GW/ 2.5GWh capacity. Our short-duration battery energy storages can balance the short-term intermittency the renewables bring to the power systems, and flexible engine power plants can provide firm and dispatchable capacity for prolonged, longer-duration balancing of the renewables. For modelling purposes, we are more than willing to share technical details of these flexible technologies as inputs for the PLEXOS® model.

4. Clarify hydro modelling methodology. Limit energy shifting and hourly flexibility of hydro assets based on real-life constraints. Validate hourly plant-level dispatch with actual plant output data.

Hydro power represents the largest source of electricity in Pakistan's generation mix and the second largest source based on installed capacity (~9.9GW in 2021). The IGCEP-22 report outlines an ambitious plan to double the hydel fleet of Pakistan over the next 10 years. The short-term objective is deploying 5 GW of new capacity until 2026, while the total hydro power capacity is expected to cross the 22 GW mark by 2031.

Based on historic hydro generation data, hydro plants operate with an average 45% annual capacity factor in Pakistan. Two third of the total annual generation falls for only 5 months (from May until September), thus hydro generation registers a relatively low-capacity factor for the remaining time of the year.

The State of Industry 2021 report points out that in August 2020 the utilization of hydropower plants reached around 74% of the overall dependable capacity of hydro power plants, while it touched the lowest around 15% utilization in January 2021. Does this mean that hydro plants can operate with full output in 15% of the time in January and can be completely shut down for the remaining 85%? Most likely not, so the modelling challenge is given.

The low monthly capacity factor may enable PLEXOS® to dispatch hydro as the main source of flexibility in the grid. It is essential to clarify to what extent hydro can serve this purpose. The proper definition of the real-life capabilities of hydro plants is crucial.

In other international integrated resource plans (for example in Namibia, Cameroon on Brazil), Wärtsilä has witnessed instances where despite the relative large "virtual flexibility" of hydro assets, the actual hour-by-hour load change capability of the hydro fleet was strongly limited by water flow constraints, irrigation-constriants, lack of advanced control system of hydro plants or to avoid high wear (increased maintenance) on the turbine blades when operating as grid-balancer.

Most of Pakistan's hydro reservoirs and dams primarily fulfil an irrigation purpose, therefore the real-life flexibility of these assets is limited. The IGCEP-22 study does not provide sufficient information on how these real-life considerations were considered as it only mentions seasonal and monthly characteristics (Section 3.6.3.).

Wartsila suggests applying not only seasonal and monthly generation limits (*Max Energy Month*) for the hydro fleet, but also introducing weekly, daily and hourly minimum and maximum hydro output constraints, that are based on actual, measured hydro generation data. This will prevent the model from being overly optimistic about the system's long-duration or seasonal energy-shifting capabilities, and ultimately improve the accuracy of the IGCEP-22 forecasts.

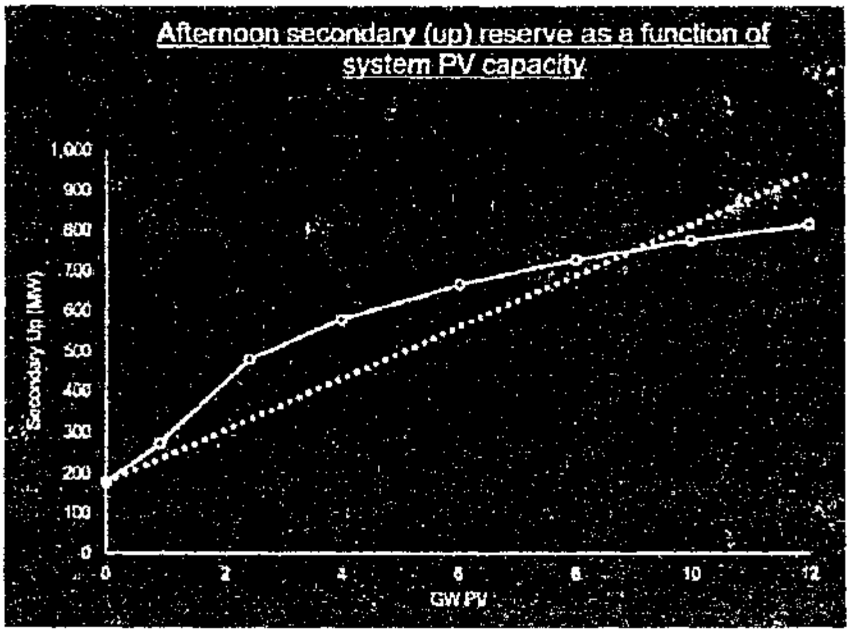
Furthermore, the risks related to delayed construction times (globally and in Pakistan, hydro projects are invariably delayed), the unreliability of seasonal flows and droughts, and the competing demand for irrigation and drinking water needs should be considered as well.

5. **Add the sufficient and right amount of "renewable balancing reserve" in the LT model to cope with the renewables forecast error**

In modern power system modelling, in addition to the common contingency reserve and secondary reserve, it is getting popular to add renewable balancing reserve to allocate enough operation reserve to balance possible forecast error with the variable renewables. We are delighted to see in this version of IGCEP 2022-31, on top of existing reserve requirements, additional reserves have been added to cater for variable renewables intermittency (section 3.6.5, pages 30-31).

While the inclusion of reserves for renewable balancing is the right step to further improve the modelling quality, we would like to comment on the reserves needed and the distinct requirements for renewable reserves. From our modelling experience, renewable reserves normally fall within the range of 10-15% of solar PV and wind actual generation, which is much higher than the current numbers used in the IGCEP report model.

For example, Emirates Water and Electricity Corporation (EWEC) has presented its outlook at the Dubai Expo Energy Storage Forum[3] on how solar PV deployment will increase the grid's secondary reserve requirement. EWEC projects an estimated 11% additional secondary reserve requirement for every unit of solar PV deployment. Thus, every GW of solar PV installation will require an additional 110 MW balancing reserve during the operation hours of the solar PV plant.



Operating reserve requirements as a function of solar PV deployment (EWEC)

More importantly, not all technologies can provide renewable balancing reserves. Rapid changes in solar PV and wind output will require this type of reserve to be activated in 10-30 minutes. In turn, this means that slower power plants must be spinning to provide this reserve, which leads to extra cost because of running on part load). Simultaneously, faster power plants can provide reserves for this from non-spinning sources, which leads to more optimum operation of the system.

[3] EWEC's presentation at Dubai Expo Battery Storage Forum (starting at 1:04:00) https://www.youtube.com/watch?v=xX4pqJGgLwc&t=4374s

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Summary

In conclusion, there are five main points we would like to comment on regarding the current IGCEP 2022-31:

1. Validate the long-term expansion study with a short-term model while using a higher level of detail
2. Include more dynamic properties of power plants in the model
3. Consider additional new-built technology candidate options, such as flexible multifuel engines, energy storage, or flexible demand
4. Clarify hydro modelling methodology. Limit energy shifting and hourly flexibility of hydro assets based on real-life constraints. Validate hourly plant-level dispatch with actual plant output data.
5. Add the sufficient and right amount of "renewable balancing reserve" in the LT model to cope with the renewables forecast error

We would be open to having a more in-depth discussion with the NTDC and other stakeholders to exchange understanding and further contribute.

We thank the National Electric Power Regulatory Authority for this opportunity to provide feedback.

Sincerely,

Muhammad Arif Akram

Business Development Manager
Wärtsilä Energy
Arif.akram@wartsila.com

ALTERNATIVE LAW COLLECTIVE

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- Cons. (CTBCM)
- M.F
19/x/22
cc Chairman
- M (M&E/CA)
- M (Lic/T)

16th of October, 2022

To: Registrar NEPRA
NEPRA Tower, Attaturk Avenue (East),
Sector G-5/1, Islamabad.

Subject: <u>Comments on the Indicative Generation Capacity Expansion Plan (IGCEP) 2022-2031.</u>

Dear Sir,

1. The following comments are being submitted by the Alternative Law Collective (ALC) on behalf of the Alliance for Climate Justice and Clean Energy (ACJCE) with reference to the Notice for submitting Comments in the matter of Indicative Generation Capacity Expansion Plan, 2022-2031 ('**IGCEP**') invited by your respected Office through advertisement on your website.

2. ACJCE is a coalition of various civil society organizations comprising lawyers, journalists, academics, and policy professionals, specializing in environmental issues with a focus on the energy sector – particularly the transition away from fossil fuels and towards renewable sources. The undersigned counsels of ALC and the endorsing organizations of the coalition are submitting these comments as concerned citizens and groups who are likely to be affected if the IGCEP is approved through the present process and in its current form by the authority. We offer these comments both as groups committed to a just energy transition, but also as citizens who stand for a socially inclusive, environmentally green energy policy, and as responsible members of the academic, policy, journalist, and legal fraternities, who hope to see Pakistan's energy sector grow and prosper in line with the principles of sustainable development that are the cornerstone of the regulatory process.

REGISTRAR OFFICE
Diary No: 10886
Date: 19-10-2022

ALTERNATIVE LAW COLLECTIVE

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3. The present IGCEP 2022-2031 reveals considerable improvements over its predecessor (IGCEP 2021-2030), particularly in the attempts to meet ARE 2019 targets with VRE additions, in the incorporation of RE based distributed generation, and in the modeling of alternative low demand and/or high demand scenarios. These improvements are very welcome and indicate a praiseworthy attention to policy goals and the feedback of civil society stakeholders. We applaud this attempt to correct some of the errors of the past. However, we are of the view that there are nevertheless serious deficiencies in the present IGCEP 2022-2031 that warrant revision of the document. In its current form, the IGCEP report continues to suffer from various technical shortcomings and errors that reveal infirmities in the planning process as a whole. Like its predecessor IGCEP 2021-2030, The methodology followed by the IGCEP 2022-2031 frustrates the very purpose of a reasoned exercise in least cost modeling, and the present process is antithetical to the values of transparency, accountability, and efficacy that are the cornerstone of effective evidence-based practices in energy planning. Consequently, the IGCEP is subject to a number of internal contradictions and the proposed energy mix and road map for capacity additions is often inconsistent with the principles of sustainable development. We detail some of these limitations below and offer our comments in the spirit of "constructive criticism" with the hope of generating an informed dialogue on the planning process as a whole.

A. THE PROPOSED IGCEP FAILS TO UNDERTAKE AN UNCONSTRAINED, EVIDENCE-BASED, AND INDEPENDENT ASSESSMENT OF LEAST COST OPTIONS RESULTING IN A SUBOPTIMAL OUTCOME.

As pointed out by multiple stakeholders in last year's IGCEP hearing, NTDC's failure to conduct an unconstrained analysis of the energy options violated the basic purpose of a least cost modeling exercise. This fundamental flaw stands uncorrected in the present IGCEP 2031. In fact, this basic

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error has not only been repeated but also exacerbated by several factors as outlined below. There are various facets to this planning failure, each of which require correction if the document is to achieve its true goal of developing an evidence based and analytically sound roadmap for a sustainable and cheap energy mix.

- **Definition of Committed Projects:** The manner in which the category of "committed projects" has been defined means the planning process is rigged from the start, rendering the entire exercise of least-cost modeling futile. This error can be traced to IGCEP 2030, which introduced an arbitrary, unreasonable, and highly objectionable change in the then existing criteria for classifying a project as "committed." Prior to last year's IGCEP, a project used to be classified as "committed" only if it fulfilled one of the following prerequisites:

    - "It is already under construction;
    - Has achieved financial close;
    - Has strategic importance i.e. China-Pakistan Economic Corridor (CPEC) project;
    - or is a G2G project."

In the IGCEP 2030, however, this criteria was changed and a projects was considered "committed" if they fulfilled the following criteria:

- Has obtained LOS as of December 2020 for private sector projects. For Federal Government 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 power project shall be modeled as candidate projects to be evaluated under least cost principle.

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- G2G project: Power Generation projects which are listed under Federal Government's international (bilateral or multilateral) commitments, if project / financing agreements signed.
- Where timelines of completion of a project under G2G are not firmed up yet. The tool shall determine the timeline by which such a project must come online based on its tariff optimization with respect to other available options.
- RE plants (Wind, Solar, Bagasse) enlisted in Category I & II of CCoE's decision dated 4th April 2019.
- 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.

No rationale for this change in criteria was provided – particularly for the easing of the criteria from "under-construction or financial closure" to merely obtaining an "LOS for private projects and "the approval of a PC-1" for public sector projects. The problem isn't that some projects have their CAPEX costs omitted from the least-cost modeling analysis – this may make sense under some exceptional circumstances. Industry best practices the world over aim to limit accommodation of such 'committed' projects very strictly to those cases where significant investments in project development and construction have already been undertaken, and financial and contractual obligations have been firmed up such that shelving the project at such a stage would result in more losses to the market and the public overall. In general, this only applies to situations where the power purchase agreements have already been signed for projects that have proved their least cost credentials previously. The underlying rationale for such pre-selection is to avoid expensive and inequitable outcomes where project developers who have already incurred significant expenses and placed reliance on contractual agreements end up getting penalized because of ex-post facto changes in market optimality outlooks. The

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present criteria on the other hand is entirely arbitrary and pre-selects projects so early in the project development cycle as to effectively guarantee a seat for mere abstract proposals with no real developments on the ground allowing them to bypass the least cost optimization process.

Last year, more than 80% of the capacity additions were pre-selected on grounds other than their least cost credentials owing to this arbitrary criterion. This year's plan has fared no better with committed projects taking up well over half the share of the energy mix on average. Through this backdoor mechanism, the IGCEP has added a substantial number of fossil-fuel based and large hydro projects that have been exempted from a least cost testing against RE technologies to determine their competitiveness. This includes 4,203 MW in coal and gas based energy, and a whopping 7,111 MW of (mostly large) Hydropower projects. The share of committed solar and wind is negligible by comparison. Given that wind and solar are vastly more competitive even on purely economic grounds alone, this methodology sets up an uneven playing field. Relative to Coal, Gas, and Hydro, cheaper and cleaner RE projects have therefore been placed on an unequal footing without a fair competition. It is important to point out that this outcome has nothing to do with 'technical considerations' related to grid limitations or issues of intermittency and the base load reliability needs of the system – it is purely the result of an unjustified and unreasonable intrusion of political bias in the planning process. The same has been forcefully noted in a World Bank report on RE integration in Pakistan which observes that "some committed plants are only drawn because of their status but not because they make economic sense or are needed for supply." The resulting mix is therefore patently sub-optimal in terms of both economic costs and environmental sustainability. This outcome results not only in substantial economic losses to the public but also frustrates NEPRA's statutory goal of developing competitive markets. This criterion therefore amounts to a circumvention of the market and regulatory process through a pre-selection of preferred projects which is simply a poorly concealed form of market nepotism. This will considerably hurt investor and consumer confidence in the possibility for a free market for electricity – particularly for the renewables

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industry – which is a present priority of NEPRA especially with the CTBCM reforms and the shift to competitive bidding for renewables enacted this year.

- **The Role of the Independent System Planner**: The issue runs deeper than a mere question of classificatory criteria and pertains to a fundamental misconception of the true role of the system planner and the regulator in the planning process. The purpose of the modeling exercise is for the system planner to generate an accurate and technically sound least-cost plan based on an unconstrained analysis of all the possibilities and options, carried out on a complete and independently verified data set, through a process that is free from political influence or partisan interests. A successful execution of this task depends on at least four factors:

  (i) complete access to any data that is relevant to assessing the true costs of any technology, project, technical factors, and integrated system wide costing of the overall capacity additions roadmap;
  (ii) transparent analytic procedures based on reasonable assumption sets, parameters, and metrics that are developed independently of political interference and are publicly testable;
  (iii) sensitivity analysis to stress test for contingencies and multiple planning scenarios to determine the cost of any anticipated or proposed deviations from the base case least-cost plan;
  (iv) analysis of complementary methods for achieving energy security goals that would result in the most impactful overall integrated plan.

  The assumptions of the present IGCEP 2031 as laid out in Section 5.2 and the list of scenarios modeled as laid out in Table E3 fail to meet these standards for the following reasons:

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→ Under the Grid Code, NTDC is bound to collect relevant data regarding operational and future power plants from various entities in the sector. Neither the input data nor the methodology for collecting and analyzing it have been disclosed in the IGCEP. It is unclear which data NTDC obtained, whether it is complete or not, what the rationale for omitting some types of data might be, and what methods were employed for testing the veracity of the data. Since this data constitutes the basic inputs and information on which a last cost-modeling exercise is conducted, verifying its completeness, veracity, and reliability is a necessary step –indeed the most important one. The IGCEP appears not to have fulfilled this requirement. The only guidance we get on this issue is in Section 3.4 of the study which states that the Financial Parameters have been obtained from 'concerned project executing entities' and 'the latest tariff determination available on the NEPRA website.'[1] These financial parameters are unreliable and biased, being fully dependent on the self-reporting of power plant costs by the project executing entities. This financial self-reporting (misreporting) has historically been accepted by NEPRA without objections and sans any independent verification and/or assessments by experts in energy finance and project costing. Such self-reported data has previously been relied upon for important policy decisions with disastrous effects as detailed in the 2020 'Report on the Power Sector' ('**RPS**'), the Committee for Power Sector Audit, Circular Debt Resolution and Future Roadmap. A single example should suffice to demonstrate the gravity of such misleading financial practices: in the case of just one coal fired power plant i.e. Huaneng Shandong Ruyi (Pakistan) Energy (Private) Limited located at Qadirabad, District Sahiwal, the committee calculated excess payments of Rs. 291.04 billion over the tariff control period of 30 years. The entire culture and system of costing practices that stand at the heart of the IGCEP are therefore hit by structural defects and bias. Its integrity is compromised in equal parts by the self-interested nature of the reporting, ineffective or incomplete disclosures, misleading data, and questionable financial practices of the

[1] P. 25 of IGCEP.

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project executing entities. These erroneous costs claimed by the project executing entities and approved by NEPRA have been worked into the tariff structure in the previous years and are responsible for leading us down the road of circular debt, energy insecurity, foreign debt, and financial ruin of the energy sector. The source data is therefore unreliable and potentially dangerous for the IGCEP's planning purposes.

➔ The reliance on a singular externally dictated assumption set by NTDC is prima facie inconsistent with the National Electricity Policy 2021 (NEP). Section 5.1.1 of the NEP states that: "Expansion in generation capacity shall be only on competitive and least cost basis (except for strategic projects, for which: (a) the qualification and methodology shall be provided in the National Electricity Plan, (b) the Government, in consultation with the Provincial Governments, shall approve such projects on case-to-case basis and (c) the relevant sponsoring Government / Provincial Government shall provide the funding to bridge the incremental cost (beyond least cost) of any such project)." These guidelines make it clear that while actual generation expansion may proceed on lines that include strategic G2G projects that are not competitive or do not meet the least cost criteria, the incremental costs over and above the least cost alternative would have to be provided by the sponsoring Government / Provincial Government. This step presumes and requires – indeed obligates – NTDC to first submit all such strategic projects to an unconstrained least cost analysis irrespective of their guaranteed inclusion in the final expansion plan. Whatever the imperatives driving the actual inclusion of strategic projects, this unconstrained modeling is nevertheless a crucial prerequisite for realizing the "true financial cost" of the strategic or "committed" additions so that sponsoring Government / Provincial Governments may be aware of the financial implications of project choices. It is also necessary to outline what the least cost alternative to each individual committed project would have been, to help guide policy makers on other aspects of their energy choices -- such as environmental or political fallouts. It goes without saying that under S.

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14A of the NEPRA Act 1997, the Regulator is required to "perform its functions in accordance with the NEP" and by extension, NTDC is similarly bound in its role as the licensed generation and system expansion planner under the Grid Code issued by NEPRA. In the present IGCEP, however, NTDC has completely absolved itself of this legal duty. The regulator NEPRA, must therefore step in to ensure course correction on this front before any approval is conferred to the IGCEP.

➔ The problem of classification notwithstanding, committed and even existing on-line projects should not in principle be excluded or exempted in any way from being made to compete against all candidate options – this analysis should be conducted at least in the shape of scenario analysis apart from the base case. For the least cost modeling exercise to be at all purposeful, all projects and technology blocks should be subject to a principle of continued competition. Any meaningful assessment of fuel source and technology share in the generation mix should and must consider the optimality of technology option irrespective of the stage in the life cycle of a project. It should be noted that NTDC is tasked with identifying the optimal balance of least cost and environmental suitability of the fuel mix in the decade ahead. This duty requires application of mind and meaningful evaluation of the actual set of options not only for capacity addition but also for replacement of existing and retiring projects or shelving of committed projects. In principle, therefore, the IGCEP should have specified and worked on multiple scenarios and sensitivity analyses for determining the true least-cost and sustainable pathways for future additions.

In light of the above, NTDC's methodology with the IGCEP invites especial scrutiny for its inconsistency with the intent, letter, and spirit of the ARE policy. By protecting committed and existing fossil fuel and hydro projects from a fair competition against RE technologies, the IGCEP contravenes the long term vision and values of the ARE policy. As stated by the ARE "In addition to generation capacity expansion, AREPs shall also be solicited for displacement of expensive electricity generated using fossil fuels (thermal

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plants). This is a major directional change from the past..." The 30% policy minimum is in fact simply a mandatory minimum – not the ideal that the IGCEP should aspire to. This should apply more emphatically to carbon-based projects that are not even on-line yet, and some of which may have not even achieved full financial closure, and are subject to delays, cancellations, and other future risks. The NTDC is therefore obligated to model and propose alternative scenario options that include not simply evaluation of renewable candidates as opposed to other candidates, but also the evaluation of renewable candidates vis a vis existing and committed carbon-based projects. It bears mentioning that a recent World Bank report finds several cases where it proves more economical to shelve committed and even existing projects with guaranteed fuel offtake agreements, and accept penalty payments instead of curtailing further amounts of RE generation. Even otherwise, alternative scenarios such as renegotiation of onerous non-renewable project contracts should be included in the modeling exercise to generate meaningful options for least-cost pathways.

B. THE PROPOSED IGCEP HAS PLANNED CAPACITY ADDITIONS AROUND ECONOMICALLY AND TECHNICALLY RISKY HYDROPOWER PROJECTS

Hydropower projects – particularly large hydro – are notorious for cost-overruns, delays, vulnerability to climate change and shifting weather patterns, as well as significant renovation and maintenance costs and long-term decreases in capacity. This is quite apart from their social and environmental risks, and political costs which are especially high in the Pakistani contexts. There are several facets to the risks associated with large hydropower projects as outline below:

- **Cost Overruns and Delays:** The IGCEP includes absolutely no analysis of the cost overruns and time delays associated with hydropower projects. A recent study by IEEFA

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estimates that only 15% of the planned capacity from last year's IGCEP is likely to come online on time with the rest delayed well beyond the end of the decade.[2] This estimate is based on the pattern of existing delays, the percentage of actual physical progress made on the civil works and construction of powerhouses, and the present status of financing arrangements. The report reveals that of the nearly 14 GW of hydropower capacity scheduled to come online by 2030, only 51% had achieved financial closure and only 39% had begun physical construction as of September 2022. Experts estimate cost overruns to touch approximately USD 49-61 billion. Delays are also likely to increase power outages and load shedding prompting a switch back to fossil-fuel power to bridge the shortage.

It is worth taking a closer look at the present patterns of cost overruns and delays for some of the larger hydropower projects included in this year's IGCEP plan under the "committed" category. The World Bank-funded Dasu hydropower project has previously been hit by delays of three to four years. This massive 4320 MW project, scheduled for construction over two phases of 2160 MW each, was supposed to come online with the first phase by 2023-2024. The impact of the COVID-19 pandemic, insufficient land acquisition, and security concerns, however, have led to several delays in project progress. Unplanned costs have also been massive. After terrorist attacks last year, compensation packages of upto USD 20.3 million have had to be issued and the project contractor China Gezhouba Group Company has also sought additional compensation to the tune of USD 37 million. Together these factors have led to cost overruns of almost Rs. 100 billion (USD 450 million). The project was initially approved in 2014 with a total cost of USD 3.9 billion, but now faces an overrun of almost 12%. The fate of the 128 MW Keyal Khwar generation facility has been no different. Work on the project has been pending since 2004 and is now projected to be completed in 2027 by the IGCEP. At the time of its initial approval in 2004, the proposed facility had a PC-I cost of Rs.7.1 billion. This figure has required a revision upto Rs. 26.1 billion in 2016 – nearly 4 times the initial cost. Delays

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have also come with commercial difficulties, with the project's 2017 civil works contract terminated on accounts of non-performance of the contractor. Due to these delays, the cost of the project has exploded with the new PC-I cost amounting to Rs. 49.7.[3] Similarly, both the 700 MW Azad Pattan project and the 1124 MW Kohala project have met with similar difficulties in the past, with the latter hit by significant delays after Chinese financiers pulled out in 2018.

The challenges with cost overruns and delays are recognized as a significant variable that needs to be factored into planning decisions the world over. These factors explain the growing trend to replace large hydropower projects with smaller, more locally managed, run of the river projects. According to an Oxford study on the subject, the average overruns on the cost of a large dam is 96% with an average time overrun of 44%. The authors of the study who surveyed some 245 projects across 65 countries, concluded that "even before accounting for negative impacts on human society and environment, the actual construction costs of large dams are too high to yield a positive return." The study also highlights the role of two important factors underlying the unrealistic assessments of cost and time overruns: "optimism bias" i.e over optimistic claims on the completion of a project based on unrealistic timelines; and "strategic misrepresentation" i.e., the deliberate or negligent underestimation of costs by project promoters to push or expedite the approval process..

In the Pakistani context, these findings are especially relevant. The case of the gargantuan 4.5 GW Diamer Bhasha project – added as a committed project last year but shelved by this year's IGCEP on account of a COD beyond the 2031 horizon – is a cautionary precedent in this respect. Construction on this 4,800-megawatt plant began in June 2020, with an estimated completion cost of USD 14 billion and scheduled completion in 2027. However, when adjusted for delays and overruns, the direct costs and costs of financing have been estimated to bring the overall cost of Diamer Bhasha to more than USD 60

[3] IEEFA study "To Build or not to Build: Keeping Pakistan's Hydropower Reliance in check.

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billion with an actual operation date later than 2035. The tariff set by the Water & Power Development Authority of PKR 4.11 (USD 0.024) per kilowatt-hour – which figure was also relied upon input uncritically by the IGCEP – is therefore highly misleading. Experts estimate that the tariff would have to be kept closer to PKR 20 simply to break even in 30 years.

The large hydropower projects added by the IGCEP are also funded mostly through MDB and foreign loans adding large amounts of external debt. Extensions to Tarbela for instance are being financed mainly by the World Bank Group, and Gazi Barotha includes funding support from both the WB and ADB with a 25-year loan of USD 300 million from the former and a 20 year loan of $350 million from the latter. These projects are therefore adding massive amounts of external debt to a nation that is already stressed by debt servicing expenditures. Aside from piling on the debt, loans for large projects are often subject to considerable restructuring costs which risks are elevated given Pakistan's perilous macroeconomic situation and depleted foreign exchange reserves. Recently, in the case of Tarbela extension #5, for instance, WAPDA has struggled to pay contractors according to the deadlines stipulated in the contract. Changes in the share of co-financing have therefore been requested by WAPDA to avoid any delays in payment to the contractors. This has meant higher debt and less favorable loan terms in the long run. Any savings on capacity payments to expensive RLNG and FO projects are therefore likely to be consumed by the debt serving load of hydro projects in the 2023-2031 period. In addition, WAPDA's own financial health is presently at its nadir. Almost 70% of the planned hydropower capacity requires partial or complete funding by either WAPDA or provincial governments at a time when WAPDA has been downgraded by nearly all credible global credit rating agencies such as Moody's and Standard & Poors. This will further contribute to delays, uncertainty in investments, and unfavorable loan terms.

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- **Technical implications of delays:** There are also technical and financial implications related to replacement strategies in the event of these delays. A recent study by LUMS EI demonstrates that in even a moderately delayed Hydro scenario, given the variability of wind and solar, the system is likely to experience shortages in summers in FY27 and beyond. Aside from reducing the reliability of the system, this delay also means an increased dispatch for Gas and Local Coal to fill in for the expected output of the Hydro power plants. The payments can be expected to surge in FY24 to more than PKR 70 billion on the back of these delays since energy must now be supplied by a larger volume of thermal power plants. The analysis shows that over the modeled period, there could be cumulative energy payments of several hundred billion PKR resulting from use of more expensive and/or imported fuels to replace energy from low-cost delayed Hydro. Given this evidence, the costing data, tariff indexation, and information for hydropower projects provided in the Annexures of the IGCEP are misleading and incomplete. A more complete analysis of the true costs of hydropower is in order.

- **Hydrological risks:** The IGCEP has also failed to adequately factor in climatological and hydrological risks to the hydropower pipeline. Hydropower projects have historically been vulnerable to extreme weather patterns and seasonal shifts. This vulnerability has increased exponentially with climate change patterns, the effects of which have been seen across the globe in the shape of droughts, shrinking rivers, extremes of high and low precipitation, and unpredictable reservoir levels. In Pakistan, this year's early onset summer and unprecedented heat waves saw alarming drops in the reservoir levels followed by the catastrophic floods later on. This is not a 'one off' event. According to recent studies, climate change is expected to drastically affect the availability and predictability of water as a resource for power generation with at least a third of glacial volumes expected to be lost in the coming decades. Thus we can expect a reduced and more unstable supply with diminished or unpredictable flow profiles in the coming years. The IGCEP provides no meaningful assessment of this hydrological risk

Aside from the climate risks posed by large dams to the Indus Basin as a whole, there are technical considerations related to decreased summer output that the IGCEP has failed to account for. The situation is most concerning in the early summer months of May and June when the demand starts to peak but the output from Hydropower plants (which is more than a third of total installed capacity) is subdued. This raises the risk of load shedding in this period. The IGCEP carries out no sensitivity analysis for the system wide implications of this scenario, merely implying that the system achieves LOLP of not more than 1% per annum. In Section 3.6.3 for instance, the IGCEP states that the "average seasonal values of monthly energy and capacity, as conveyed by the concerned project executing agencies, have been used to capture the seasonality in the output of hydroelectric projects." Quite apart from the absence of any independent verifications on this data as outlined previously, this analysis appears to be based on average monthly values from past years. A more useful method would have been to analyze LOLP and model generation on the hourly water flow profiles as experienced in recent years and as projected over the 10 year period after accounting for shifts in hydrological patterns owing to the increased climate risks. The key task was therefore to analyze the evidence regarding changing hydrological patterns to test whether the loss of load probability increases in May and June with lower contributions from Hydro. Similarly, there has been no costing or planning of alternative arrangements for making up peak demands in a low hydro scenario. In the absence of these, the system is likely to experience shortages in summers in FY27 and beyond. This can potentially reduce reliability of the system and need to be considered for generation planning

C. THE DECISION TO EXTEND KAPCO (BLOCKS I & II) VIOLATES THE LEAST COST PRINCIPLE AND IS OUTSIDE THE REMIT OF THE IGCEP

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The IGCEP's arbitrary extension of KAPCO beyond its PPA period is an inexplicable and contradictory feature of the plan. The standard practice on retirement schedules has been outlined in Section 5.8 of the IGCEP as follows: "For the purpose of the IGCEP, a power plant stands retired either as per its PPA / EPA term or relevant CCoE decision." Section 5.2 of this year's IGCEP however, announces a "minimum dispatch of 500 MW from KAPCO CCPP (Block I & II) has been provided in the months of May to September till the year 2025 beyond its PPA expiry of Oct 2022." This extension has therefore been taken as one of the assumptions of the current plan. However, no reference to any relevant decision by the CCI or the CCoE has been offered. The ostensible reason given by NTDC for this extension is "network requirements and constraints." The IGCEP however provides no reference whatsoever to what those constraints are and why extending KAPCO Block I & II is the best suited, least cost option for meeting needs in the presence of other candidate technologies. In the absence of any policy based directive, or least cost assessment, such bypassing of the process and unilateral decision making through arbitrary, opaque, and self-legitimating criteria is tantamount to an abuse of authority.

Moreover, it is curious that the IGCEP has selected a project for capacity addition based on transmission related factors in the absence of an attending TSEP directive. The IGCEP goes on to state that "it is pertinent to mention that the requirement of KAPCO beyond its PPA expiry will be assessed in ongoing Transmission System Expansion Plan (TSEP), accordingly competent forum will be approached, after consensus among concerned stakeholders..." This clarification in itself demonstrates the objectionable nature of this inclusion. If NTDC wishes that KAPCO be provided such an extension on grounds related to transmission constraints rather than least cost credentials, that preference ought to be first validated as a consensus decision as part of the TSEP analysis. Else, it may be modeled as an alternative to the least cost base scenario through a separate sensitivity analysis. Such an analysis must also outline the costs of such an extension and specify its expenditure beyond least cost alternatives. KAPCO is one of the most expensive and a major contributor to the capacity payments problem being faced by the power sector.

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D. THE IGCEP LOCKS IN AN UNFAIR ADVANTAGE TO LOCAL COAL IN THE MERIT ORDER

The tariff determinations of Local Coal plants segregate the fixed fuel cost components as capacity payment on account of the upstream tariff structure of the mining projects. As a result, around 70% of the fuel cost is paid as 'capacity' while the remainder comprises the fuel cost component factored into the merit order for dispatch. This confers an unfair advantage to Local Coal plants as they end up ranking higher in the merit order and are prioritized in dispatch. This priority however, is artificial owing to the aforementioned structure of the tariff. As a result, the IGCEP roadmap may lead to a more expensive and less competitive method of meeting demands from within the existing generation options. NTDC appears not to have factored this into the analysis.

E. THERE IS NO COMPARATIVE ANALYSIS OF ALTERNATIVE SOURCES FOR REPLACING IMPORTED COAL IN THE GWADAR PROJECT

The IGCEP 2031 makes an important improvement over last year's plan in transitioning the committed Gwadar Coal-Fired Power Project away from expensive and highly polluting imported coal. However, the IGCEP conducts none of the analysis needed for subsequent assessments of appropriate replacements. It merely reports that the project has shifted to local coal "as conveyed by the relevant project executing agency i.e. PPIB", without first evaluating the costs of this arrangement, the alternative options, and the least cost choice. This decision is particularly baffling given Gwadar's prime suitability to solar and distributed RE solutions – both in terms of costs as

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well as for reasons of present limitations in the grid. The suitability of solar solutions for Gwadar has been acknowledged by the power division itself. Since the preference for coal as opposed to solar has serious financial implications, and the question has been the subject of much debate amongst policy makers, a proper comparative analysis should have been conducted in order to determine the most suitable least cost fuel source for this transition.

F. THERE IS NO CLARITY ON HOW KE'S LEAST COST MODELING HAS BEEN CONDUCTED OR INCORPORATED IN THE PRESENT IGCEP

This year's IGCEP incorporates the least cost plan developed independently by K-Electric. However, it provides no clarity on the methodology, assumption sets, and data sources of the latter or the method for verifying the optimization choices. This has led to the additions of projects that are plainly unreasonable on the face of it The IGCEP, for instance, includes the 82 MW Turtonas Uzgor Hydro project as an optimized K-Electric Candidate. The said project however, is based in Golan Gol, Chitral, some 1750 km from the K-Electric jurisdiction. It defies reason as to how this project can reliably and cheaply provide electricity to consumers based in the K-Electric service area, particularly given the vast potential for cheaper solar and wind options in the Sindh region. The analysis and justification however, is missing from the IGCEP.

G. THERE IS NO DISCUSSION OR PLAN FOR DEMAND SIDE MANAGEMENT DESPITE ITS INCLUSION AS A "MUST DO" PRIORITY FOR FUTURE ACTION IN LAST YEAR'S IGCEP

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The data on seasonal variation in demand and generation reveals a massive contrast between peak period generation (June to August) and off-peak period generation (December to February) over the last decade. While peak period generation has increased 60%, off-peak period generation has increased only by 27%. This points to the massive and rapidly growing gap between usage in the summer and winter – mostly driven by a small and privileged set of urban consumers increasingly reliant on air conditioning in the summers. As shown by a recent study on the previous year's IGCEP by the LUMS Energy Institute, the capacity margin peaks to 63% in the initial years during winter periods, while in summer periods it reduces to 25%. Towards the end of the 10 year modeling period, the same margin reduces to less than 40% in the winter and to 17% in the winter. The analysis reveals that the system remains in large amounts of surplus throughout most of the year owing to the volume of the capacity additions. Capacity margins are therefore significantly higher during off-peak demand hours in winter when the load is around 7-9 GW. This trend is set to remain through the next decade.

The best practices amongst power system operators is to maintain a capacity reserve margin of 10-15% in order to balance reliability with affordability. However, as noted by the aforementioned study, in the case of Pakistan's power sector, "ill- planned decisions and over-commitment have driven the system into excessive, and expensive surplus. The situation will become worse if the demand grows at a lower rate, putting upward pressure on the ratepayers' rates to recover the same costs of this over-committed capacity."

The IGCEP fails to conduct any analysis of this troubling demand side imbalance, its root causes, financial implications, or its connection to sub-optimal planning choices in the past. It also proposes no solutions for addressing the problem. Given the present demand side trends, capacity arrangements of several thousand MW's have to be made for only 10-15% of the consumers – that too for no more than the duration of a few hours for a couple months in the summers. This amounts to losses extending to several millions. Recent evidence, for instance, suggests that a mere reduction of 1000 MW can provide annual capacity savings upward of 100 million USD and total annual savings in energy costs of more than a billion USD. Given that the core purpose of the IGCEP is to chart out a sustainable "least cost" plan, this negligence of the demand side of the energy equation is perplexing. This is especially so given that the previous iteration of the IGCEP explicitly mentions demand side management (other than NEECA efficiency targets) as a "must do action" item.

II. THERE IS NO DISCUSSION OR PLAN FOR INCORPORATING HYBRID TECHNOLOGIES AND BATTERY STORAGE OPTIONS IN ORDER TO FAST TRACK THE INTEGRATION OF RENEWABLES

Hybridization of variable renewable energy projects – particularly through combining solar PV and wind with battery storage – is a recognized pathway for expanding the share of clean energy sources in the grid. Last year's IGCEP recognizes the significance of such solutions and notes that "future plans are required to be aligned with international best practices pertaining to renewable energy." The typical problem cited as a barrier to expansion of RE is the problem of intermittency. However, not only do solar and wind complement each other in terms of hourly and seasonal profiles, in the presence of battery solutions, they may provide a reliable and continuous supply of electricity to the grid. Such technologies – particularly battery solutions – are gaining in popularity around the world owing to massively declining costs. Section 7.1 of last year's IGCEP notes that "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." This year's IGCEP however, fails to incorporate hybrid and batter solutions nor does it model their market trends to test for its implication on least cost pathways for the integration of further RE.

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I. THE PROPOSED IGCEP IS LIKELY TO EXACERBATE REGIONAL DISPARITIES IN ENVIROMENTAL IMPACT AND PRECIPITATE INTER-PROVINCIAL CONFLICT.

Inter-Provincial Inequity: The combined coal and hydel focus in the generation mix is an especially toxic combination given the interaction between the environmental impact profiles of these technologies and the regional dynamics involved in their deployment. Hydel potential is concentrated in the north – mostly in KPK, but the negative impact of low water flow shall be experienced in lower riparian areas – especially in Sindh and Southern Punjab. In addition, coal mining and burning which aside from the aforementioned emissions risks is also notoriously water intensive and poisonous to the local hydrological resources is also heavily concentrated in the South, particularly in Sindh, South Punjab, and Baluchistan – regions which are already threatened by desertification, water scarcity, drought and sever water pollution. The IGCEP simply does not take into consideration the injury of the upstream new hydro-power projects on the down-stream provinces. No attempt has been made by the IGCEP to evaluate the effect of these projects on the minimum flow of water in the riverbed downstream. Without prejudice to other environmental injuries, the right of the upstream provinces to build dams, hydel power reservoirs, on or divert water from a shared resource cannot be had at the cost of the right of downstream provinces to have access to the minimum flow of water in the riverbed.

Given Pakistan's present provincial disputes especially around water, the focus of the policy as it stands amounts to a reckless inflaming of existing conflicts in the state as well as the propagation of a disproportionate ecological and climatic impact in Sindh, Southern Punjab and Baluchistan. It is thus inconsistent with the objectives and guidelines of the NEPRA Act and ARE policy both of which call for energy plans that enhance social equity and envision the adoption of measures meant to "mitigate adverse climate change and to effectively manage conflict of interest of the State in relation to development of the electric power markets of the Islamic Republic of Pakistan. The controversy surrounding last year's hydro heavy IGCEP which drew considerable objections from Sindh highlights the need to re-consider the proposed expansion carefully.

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success of any long term strategically important plan is dependent on the methodology and on the envisaged sequence of events under the plan. Logic dictates that NTDC should have first prepared a 'Transmission System Expansion Plan' to meet the ARE minimums and on the basis of information provided to it by the Ministry of Power of GoP, PPIB, AEDB, and all provincial agencies. The ARE policy expressly envisions this sequence of events:

> "It has been decided that rather than inducting RE projects on a reactive basis, a new policy direction is being set…It is estimated that such targets can be achieved but will require upgradation of the transmission infrastructure; this exercise will be undertaken in parallel and, where necessary, as a pre-requisite"

It is more appropriate to the remit of NTDC for it to devote its efforts first to the development of a technical and financial plan on how to expand and improve transmission and distribution in order to evacuate power from a power project and to determine the cost of transmission lines thus allowing more meaningful determination of demand and supply forecasting and a more accurate modeling of the true least cost and long-term sustainable generation mix. At the very least, a well coordinated and simultaneous process of developing the TSEP and the IGCEP should have been followed. This would have better enabled NTDC and NEPRA, Ministry of Power of GoP, PPIB, AEDB, and all provincial agencies to take an informed and comprehensive decision regarding the procurement of power from any particular technology and project. However, here, the IGCEP has that sequence backward. How then is it possible for NTDC to compute accurately and predict reasonably the true least cost long-term option when the details of the underlying transmission infrastructure, its upgrading costs and improvements in ability to support different technologies long term have not yet been evaluated?

In fact, the IGCEP choices can often be complemented by the Transmission System Expansion Plan since the latter could even be an alternative to generation in given cases. Planning for

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generation in the absence of the same would be counter-productive. In addition, the Grid Code requires NTDC to identify new demand and generation requirements by capacity, commissioning date, and **location**, the latter has not always been identified and may change the outcomes envisaged in the IGCEP. When the analysis is performed in tandem with a TSEP, the true cost of end-to-end electric supply can better be evaluated for all generation options. Thus, an end-to-end cost analysis of electricity supply should be considered for all generation plants. At present, the evidence suggests that while large-scale RE deployment is possible without a major expansion of the transmission interconnections between the three zonal regions (north, south, and midland), there is a need for greater distributed deployment for both RE and non-RE sources with the former allowing for much lower costs in the event of inter-zonal expansion of transmission infrastructure as well as higher optimality outcomes in case of distributed generation.

IGCEP has also determined the need to install more capacity without catering for transmission and distribution inefficiencies and losses, which by some studies of NEPRA amount to 23% to 25%. IGCEP has considered least cost solution using a combination of CAPEX, OPEX and Capacity factors. The IGCEP has not added in the separate cost of transmission line and related losses, dispatch requirements, and consumption patterns. A resolution of the T&D losses is likely to reduce the need to install more fossil powered stations, especially Coal Fired Power Projects.

The undersigned request your respected Office to be allowed and invited to participate in any public hearings to further evince the above provided comments.

Regards,

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(Lahore)

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The following member organisations of the Alliance for Climate Justice and Clean Energy (ACJCE) have endorsed these comments:

S#	Organisation Names	Logos
1	Indus Consortium for Humanitarian, Environmental And Development Initiatives	
2	Alternative Law Collective	
3	The Knowledge Forum	
4	Policy Research Institute for Equitable Development (PRIED)	
6	Lok Sujag	

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INDUS CONSORTIUM

For Humanitarian, Environmental & Development Initiatives
A company setup under Section 42 of the Companies Ordinance,1984

Indus Consortium
For Humanitarian, Environmental & Development Initiatives

Date: 18-10-2022

Reference: ________

To,

The Registrar NEPRA
NEPRA Tower, Attaturk Avenue (East),
Sector G-5/1, Islamabad.

Subject: **Submission of Comments on NTDC's Indicative Generation Capacity Expansion Plan 2022-2031 IGCEP (2022)**

Indus Consortium for Humanitarian for Environmental & Development Initiatives, a collaborative platform of 60 civil society organizations– is a manifestation of a joint force of the people living around the Sindhu (Indus) River basin in Pakistan. The consortium represents the unity among various groups of different ethnic, linguistic, and geographic features and their resolve to struggle for the development of the people around the Indus River basin whose forefathers, in the ancient ages, had developed one of the most prosperous civilizations around the globe; remembered in history as Indus Civilization.

The Indus Consortium is working on Environment, Climate Change, Just Energy Transition, and irrigation water governance-related themes in Pakistan. The consortium partners include academia, Environmental Organizations, CSOs, working with riverine & Deltaic communities, journalists' communities, Entrepreneurs, women-headed organizations, and working with persons with disabilities, etc.

The Comments on NTDC's Indicative Generation Capacity Expansion Plan for 2022-2031 in the proposed IGCEP (2022) have been submitted by Indus Consortium on 18 October 2022 at NEPRA HQ, Islamabad.

Submitted by

Name: Hamza Bashir

From: Indus Consortium

Received by

Name:

From: NEPRA HQ, Islamabad

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HELP Foundation

Comments on IGCEP 2022-31

Submitted by civil society groups, academics and representatives of lower riparian groups

Represented by Indus Consortium for Humanitarian, Environmental & Development Initiatives

Introduction

1. The new iteration of NTDC's Indicative Generation Capacity Expansion Plan (IGCEP 2022-31) continues the alarming trend of heavy reliance on coal and large hydro projects to meet Pakistan's future energy needs. As members of Pakistani civil society, we identify the problems of overreliance on hydropower and the continued reliance on coal in the energy mix. In particular, we point to various technical, economic, social and environmental costs, and how these are overlooked in NTDC's energy plans.

2. Last year we focused on hydropower projects and raised our concern that the social, political and environmental impacts are sufficiently addressed, that this would lead to many crises and the cost will have to be borne by marginalized and poor communities: "We fear that if these challenges are not sufficiently addressed and alternatives are not fully explored, the shift to hydropower will create a myriad of problems including: worsening the water and environmental crises in Pakistan, increasing water distribution conflicts, destroying river and wetlands ecology, increase coastal erosion and sea intrusion, and *increase the risk of severe floods that may cause tens of billions of dollars in damages.*"

3. This year's plan repeats the old mistakes. Touting coal as 'indigenous' and hydropower as 'renewable', the NTDC continues down a path that relies on false and dated solutions despite the presence of better alternatives. Development of coal projects continues despite the GHG and public health issues for the country, and particularly issues of water scarcity and toxicity, air pollution, and land dispossession of the local population. The numerous large hydro projects have a history of delays, increased costs, reduced profits, along with incomplete assessment of the social and environmental impacts. In Pakistani context these are also a politically charged issue, linked directly to water scarcity and exacerbation of floods. These projects are likely to exacerbate food insecurity and intra-provincial conflict.

4. In this comment, we as members of Pakistani civil society, academics, lawyers and representatives of lower riparian groups, list our various reservations and focus on the technical, economic, social, and environmental problems associated with the committed and anticipated mega projects of IGCEP. Our analysis is based on well-established findings by the scientific and policy communities regarding the cost of coal, large dams, and run-of-the-river power generation.

5. Not only will these plans increase our carbon footprint and subsequently make the impact of climate change worse, they are also increasing the environmental and ecological damage to Pakistan's water system. This is the wrong climate for investments in coal and large dams. The government needs to do a better job of including *all* costs associated with large infrastructure projects, including long-term, recurring, and cumulative costs – particularly when it relates to

issues of water management, riverine ecosystems, groundwater quality and quantity, and the overall impact on public health outcomes.

IGCEP 2022-31: Outlook and Concerns

6. The overall outlook of IGCEP 2022-31 signals a major shift from imported fuels to indigneous sources of energy generation. There are three main components of this shift. First, massive investments in hydropower, which will contribute 41% of the overall energy mix by 2031. Second, investments in variable renewable energies like wind and solar, to make up about 21% of the energy mix. And third, reliance on Thar coal for generating less than 1% of the energy mix. Fossil fuels still remain a big contributor (see Table E2).

7. Certain aspects of the IGCEP are worth appreciating. The increased share of VREs in the form of wind and solar is a welcome move, even though there's room for increasing this share. The general tendency of retiring plants with fossil fuel dependency is also a step in the right direction. Principles of least cost and attending to the political dimension of policy plans all set the right tone for achieving energy and financial independence while taking all stakeholders onboard.

8. The move towards 'indigenous' coal is touted as an achievement, particularly in light of issues of circular debt, inflation, and rupee devaluation against dollar. However, the category of 'indigenous' coal still falls under fossil fuels with high greenhouse gas emissions. Indigneouscoal refers to low-grade lignite coal found near Islamkot in Thar, where mining operations have already begun in 2 of 13 blocks, 2 power plants are in operation, and several are planned. The move towards coal does not bode well for Pakistan's climate goals.

9. In terms of committed projects, hydropower share is about 60%. The list of committed projects shows that out of 69 projects that will increase the generation capacity by 22,180 MW, 23 projects are hydropower that will generate 13,161 MW (see Table 5-3). Most of the hydropower energy will be generated using large dams. While the IGCEP report doesn't list the design specification of the various projects, a quick analysis shows that at least 10 of the 23 projects include large dams[1], including mega dams such as DiamerBhasha, Dasu, Mohmand, and large dams such as Kohala, SukiKinari, Karot, Azad Pattan, and others. While the report emphasizes that most of the dams are 'run-of-the-river' with minimal environmental and social costs, most of the share of additional hydropower generation is due to large dams, with a cumulative power of 12,718 of 13,161 MW, or about 97% of new hydropower will be done through large dams.

10. The report lists several hydropower projects as 'existing' or 'completed' even when these aren't fully operational or have faced damages in recent floods. The Neelum-Jhelum project and the Mohmand dam suffered damages during the recent floods, with the former not in operation. (Annex B, B-1 (i)).

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[1] Using the ICOLD definition of large dams as dams with a height of more than 15 meters.

11. The report justifies this shift to hydropower based on two arguments: environmental concerns, particularly with regards to climate change, and reliance on indigenous sources of fuel. Evidence from existing hydropower dams in Pakistan and elsewhere in the world shows a different story. Here we outline some of the technical, environmental, social, and economic problems associated with large dams and hydropower.

12. IGCEP report specifies the objectives of power planning as: "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.*" (emphasis added). Unfortunately, as we outline in the following sections, many of the large projects, especially hydropower and coal plants are neither least cost, nor attentive to the political constraints particularly when considering the social and economic impact on communities threatened by these projects.

<u>The High Cost of Hydro:</u>

13. **Large dams are not suitable for current climate context:** The current climate context is defined by extreme weather events. The Himalayan-Karakoram mountain ranges are one of the global hotspots of this change, and experts have predicted extreme weather events, particularly floods with a combination of rapid glacial melt and extreme rains. Large dams are usually built with 100 year flood levels in mind, but given the likelihood of extreme weather these projects may not be feasible. Moreover, large dams generate greater risk by: increasing seismic risk in mountainous areas, reducing the floodplains ability to absorb large flood events, and increasing methane emissions into the atmosphere as a result of still water in the reservoir.

14. **Will large dams be used for flood protection, and how will this influence energy generation:** With the 2022 floods, WAPDA spokespersons and policy experts have proposed dams as a solution, despite considering the patterns of rain and the fact that most of the large dams are being built in areas that were not significantly impacted by the monsoon this year. If the large dams being built in the hydro pipeline are used for flood events, they will not have enough water stored to meet the high summer energy needs. NTDC needs to clarify how these competing goals will be met in terms of the energy plans.

15. **Has NTDC incorporated the cost of evolving, dynamic risk of the proposed large and small dams?** Traditional risk assessments often assume the stability of factors defining risks, but such traditional risk assessments are unviable in the context of climate change and human-disturbances in the river basin.[2] Dam risk is susceptible to evolution over time and already existing water and land use patterns. Given that these variations are likely to impact the entire system of water management in Pakistan, would NTDC please explain how these varying risks are estimated and whether these are included in the cost estimates of per unit electricity?

16. **The glacier burst events are on the rise in the mountains:** Another serious risk factor in terms of large hydropower in the mountains is the risk of glacier busts. The glaciers in the Karakoram-Himalaya ranges are hotspots of climate change, melting at a rapid pace and, in some instances, breaking with the potential to cause glacial lake outburst floods. The recent devastating floods

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[2] Milly, P. C. D., Betancourt, J., Falkenmark, M., Hirsch, R. M., Kundzewicz, Z. W., Lettenmaier, D. P., et al. (2008). Stationarity Is Dead: Whither Water Management? Science, 319(5863), 573–574.

caused by glacial burst in India should be a cause of concern for Pakistani energy planners as we are bound to face similar extreme events in our country. Given this reality, will the NTDC explain what type of risk assessment was undertaken to incorporate these new realities?

17. **Many dam sites have high risk of earthquake:** The Himalyan-Karakoram-Hindu Kush mountain ranges are susceptible to earthquake events, and many of the proposed dams are being built in areas of AJK and Khyber Pakhtunkhwa with active fault lines and which have in recent years seen extreme seismic activity. Dams built in areas of high seismicity pose a very high-risk potential for downstream communities. Studies have also shown that dams with large reservoirs can trigger earthquakes.[3] What is the potential cost of a dam burst due to seismic activity, along with the aforementioned variations due to rapid climate change?

18. **Long gestation periods and difficulty scaling up:** Large infrastructure, in particular dams and hyd el projects don't produce any electricity until various components are completed. Unlike Wind and Solar these projects also don't scale very well. In short, there is limited flexibility once we have committed to large hydro as our central response to the energy crisis.

19. **Only 15% of the planned capacity will come online in time:** Recent research on the IGCEP hydro pipeline by The Institute of Energy Economics and Financial Analysis (IEEFA) shows that 51% of the projects haven't reached financial closure, and physical construction has begun on only 39% of the projects. Out of these, IEEFA notes that only 15% of the planned capacity will come online in time. This leaves obvious questions about the heavy investment in hydropower given its history of delays and cost underestimates.[4]

20. **Large Dams are Uneconomic:** Multiple studies have shown that large infrastructure projects, and hydropower projects in particular suffer from severe cost underestimation. Bent Flyvbjerg, Professor of Major Programme Management at the Oxford Business School, has meticulously shown that large infrastructure projects -- especially large dams --consistently underestimate or completely ignore costs of large projects, and overestimate their benefits. A recent study conducted by a team at Oxford University (Ansar et al, 2014) demonstrated that cost estimates of large dams are "systematically and severely biased below actual values." Projects run into schedule and cost overruns that can range from 150% to 200% of the estimated costs. Projects that are larger have bigger cost overruns. Furthermore, costs are usually higher in developing and underdeveloped countries. If these cost overruns are applied to the case of many of the hydropower projects proposed in the IGCEP 2022-31, we can expect the capital cost component of per unit electricity to be double. For instance, DiamerBhasha dam, estimated at 14 billion USD, could cost between USD 20 billion to up to USD 30 billion.

21. **High cost of the hydro pipeline:** Estimates show that the total cost of the hydro pipeline, without including the social and economic costs listed above, can rise from current estimates of USD 31 bn to 49-61 bn. This will likely impact per unit tariff, even if these projects ignore the social and economic costs.

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[3]Moustafa, A. (2015). Earthquake Engineering: From Engineering Seismology to Optimal Seismic Design of Engineering Structures. BoD – Books on Demand.

[4] Pakistan's vast hydropower pipeline at risk of not being materialized, https://ieefa.org/resources/fact-sheet-pakistans-vast-hydropower-pipeline-risk-not-being-materialized

22. **The social costs of dams are massive:** Beyondthe added risk and cost overruns, dams also incur large social costs. These occur primarily in terms of displacement and loss of livelihood. These costs are also severely underestimated in the IGCEP 2022-31 calculations. The World Commission on Dam (WCD), established by the World Bank, governments, and civil society actors in 1997, conducted a comprehensive study of large dams and found that global dams displaced about 40-80 million people by year 2000 due to drowning in the upstream areas.[5]

23. **Downstream displaced groups are overlooked:** Studies estimate that downstream displacement due to loss of ecology and livelihoods can be upwards of 472 million people with conservative estimates.[6] This means that the downstream loss of livelihood can be of the order of ten times of the upstream displacement costs. The cost of resettling the displaced must also be reflected in the plans, but is ignored by the EIA and SIA documents. In the context of Pakistan, the WCD conducted a case study of the Tarbela Dam and found that planners in Pakistan have only considered the social impact in the reservoir area of the dam, but not on the downstream areas.[7] These ignored costs are borne by communities, and indirectly by the national exchequer through loss of livelihood and potential revenue through taxation.

24. Let us spell out **the social cost of dams recorded in the past two decades**: Dams crush the local plants and animals by modifying their environment. For humans, the blasting and tunneling in the construction process leads to landslides, sinkholes, drying up of residents' water sources, and cracked foundations in local houses. On a macro level, people lose farms and businesses. The displacement forced by dams promotes poverty. While it is argued that the negative effects of displacement can be countered with monetary compensation, there are major flaws in the design of financial compensation for the displaced. The compensation is tied with land and asset ownership and documentation. In Pakistan, a majority of the population that lives in the vicinity of dams struggles with poverty and landlessness. They have no means to access just compensation. Lastly, locally, the dam-induced displacement is linked to rural-urban migration, crisis of livelihood, downward pressure on wages, labor and economic informality, stretch on urban resources, and extreme social and financial distress for the displaced, who usually find accommodation in the slums. There have been documented cases of depression, domestic violence, disease and even suicide among the deltaic people displaced in Sindh.[8]

25. **Dams destroy downstream ecology:** The costs of large dams are not only limited to displacement, but the environmental impact of hydropower dams are widespread and well documented. Hydropower impacts downstream river ecology by altering the seasonal flows and by potentially stocking and diverting river flows in the Indus Basin Irrigation System. Sediment trappings is a well-recognized phenomenon and lack of nutrient supply to flood plains, deltas,

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[5] WCD. (2000). Dams and Development: A new framework for decision-making: The report of the World Commission on Dams. London and Sterling, VA: World Commission on Dams.

[6] Richter, B. D., Postel, S., Revenga, C., Scudder, T., Lehner, B., Churchill, A., et al. (2010). Lost in Development's Shadow: The Downstream Human Consequences of Dams. Water Alternatives, 3(2), 14–42.

[7] Asianics Agro-Dev. International (Pvt) Ltd., & WCD. (2000). Tarbela Dam and related aspects of the Indus River Basin Pakistan. A WCD case study prepared as an input to the World Commission on Dams. Cape Town, South Africa: World Commission on Dams. Retrieved August 10, 2017, from http://s3.amazonaws.com/zanran_storage/www.dams.org/ContentPages/1311315.pdf.

[8] Hadi, Abdul, "Dams and Displacement in Turkey and Pakistan", European Journal of Economics and Business Studies, Vol 3, Issue 2, https://revistia.com/files/articles/ejes_v3_i2_17/

and wetlands severely depletes the biota and endangers large numbers of animal and plant life. While large dams are the biggest culprits, even small disruption in seasonal flows can have severe impact on fish migration patterns, which will incur economic and social costs for downstream and deltaic fishing communities.

26. **Dams in Pakistan are a big source of water conflicts:** The large dam based hydropower systems create conflicting demands between power generation, irrigation, and maintaining ecological flows for sustainable ecosystems, especially in the downstream area. We have seen this type of conflict emerge repeatedly with the Indus River System Authority (IRSA) and WAPDA at odds during the monsoon months regarding maximum water storage for later irrigation purposes or maximizing hydropower to meet summer demands by releasing maximal water. Unfortunately, environmental flows and downstream ecological communities are not considered a party in these debates, particularly riverine, deltaic, and coastal fishers and land users. Global initiatives and scientific communities have included the ecosystem users beyond energy users and agriculturalists in their stakeholders, with decommissioning and reoptimization of existing flows to meet all these various demands. Are the political, social, and economic consequences being fully considered as Pakistan moves towards further reliance on hydropower, thus increasing the stakes of some while undermining others'.

27. **Lower riparian provinces are also party to this energy planning:** Unlike wind and solar, water is a common-pool resourcethat, in its current uses in Pakistan leaves little leverage for dams relying on seasonal storage. Pakistan has a long history of water conflict at the international and sub-national levels. In particular, the province of Sindh and the Indus Delta region has seen declining flows over the years, which has added to long-standing grievances. Since most of the hydropower projects will be constructed in KPK or AJK, the gains from any tariffs for these areas are unlikely to be evenly distributed. In fact, Sindh is likely to bear most of the environmental and social cost of these hydropower plants.

28. **Hydropower will severely damage an already declining Delta:** A study conducted by NASA shows that the Indus Delta is under severe stress due to both climate change and upstream water uses, uses that include irrigation and hydropower use.[9] The consequences of these are alarming, as demonstrated by a recent report by researchers based at the Mehran University of Engineering and Technology, Jamshoro: the Indus Delta is reduced to 8% of its historic size and loses about 200 square km of land each year to coastal erosion; sea intrusion has caused water up to 100 km inland to turn brackish.[10]As per the study, the Water accord of 1991 allocates 10 MAF to the Indus Delta, but it has only received 1 MAF of water during 2018-2019. Water shortages in the Indus Delta have resulted in ongoing protest. While hydropower may not ostensibly 'divert' and 'consume' additional water, the storage of water during high-flow seasons is likely to cause further decreased flows. The Delta, once with 17 active creeks, now only sees seasonal water in Khobar and Khar creek. As per the NASA study, 960 sq km of land was lost between 1992 and 2000 due to reduced flows, primarily attributed to water shortages in the upstream projects. It is necessary to address these concerns in the hydropower centric energy plans.

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[9] Coleman, J. M., Huh, O. K., &Jr, D. B. (2008). Wetland Loss in World Deltas. Journal of Coastal Research, 24(sp1), 1–14.

[10]Siyal, D. A. A. (2018). Climate Change: Assessing Impact of Seawater Intrusion on Soil, Water and Environment on Indus Delta Using GIS and Remote Sensing Tools Final Report 2018, 149.

29. **The cost of biodiversity loss and migration**: In line with the previous comment, the loss of delta linked to hydropower storage and diversion will cost Pakistan in terms of biodiversity loss and migration. The Indus Delta contains 19 Ramsar sites (wetlands) that are considered vital for the ecology and environment of Pakistan's coastal areas. Many fish species that are an important source of livelihood for the people are going extinct: this includes famous estuarine fish locally known as *palla,* and lobsters. The important delta crop of red rice has also disappeared. The mangroves are also in decline, which provided a wall against cyclones and floods in the coastal belt. These forests and wetlands are also excellent sinks for GHGs. Consequently, about 1.2 million people have already migrated out of the delta, which will add pressures and economic limitations in large urban centers of Karachi and Hyderabad. Can Pakistan continue to ignore and afford these losses?

30. **The run-of-river 'mislabeling'**: As mentioned above, the IGCEP 2022-31 has listed many large dam based hydropower systems as 'run-of-river', ostensibly to support the claim that many social and environmental costs are minimized. As per the European Network of Transmission System Operators for Electricity, run-of-the-river hydropower is distinguishable from dam or ponding hydropower plants, where the former has natural flows while the latter do not. It is important to clarify the criteria being used to label some hydropower plants as run-of-river, whether these have significant reservoirs or even an upstream large dam. The construction of dams for 'run-of-river' hydropower also makes sense in the context of the rivers with variation in seasonal flows, which is the case for most rivers listed in the hydropower plans, including the Indus, Jhelum, and Kunharrivers. It appears that the label of run-of-river is used to 'greenwash' large hydropower dams. Moreover, the cumulative effect of many small run-of-river plants on streamflow has not been considered.

31. **Hydropower is an unreliable source of energy generation:** The notion that hydropower provides a cheap solution to Pakistan energy needs, and a shift to up to 50% of the mix, will solve Pakistan's energy crisis is absurd, and not supported by evidence. We have listed the various costs that are not accounted for in the per unit energy calculation – the costs associated with cost overruns, increased risk of failures, social and environmental impacts. The shifts in seasonal flows along with increased flood events mean that the river systems cannot be relied upon for reliable generation of electricity.

32. **Neelum-Jhelum disaster:** The recent 'failure' at the Neelum-Jhelum power plants is an important case when considering the future of the 'run-of-the-river' hydropower projects. The 969 MW project had already faced delays- proposed in 1987 with a cost of PKR 15.25 billion, but construction only began in 2008. The project proved difficult to finance, eventually receiving two loans of a total of over USD 1 billion from Chinese investors, an increase of about 600 percent than the initial estimates and a delay of 21 years.[11] The project was shut down in July 2022 with cracks appearing in one of the tunnels, and investigation of the failure is still under way.[12]

The Cost of "Indigenous" Coal

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[11] Isaad, H. (2022). *To Build or Not to Build: Keeping Pakistan's Hydropower Reliance in Check.* IEEFA.

[12] Ahmad Ahmadani, "Fault behind closure of 969 MW Neelum-Jhelum plant remains unclear", Pakistan Today, July 19, 2022

33. **Coal is still dirty:** We take this opportunity to register our reservations about the planned dependence on indigenous coal. Coal, whether indigenous or imported, is still dirty fossil fuel. It will not only increase Pakistan's carbon emission footprint, but it will also increase costs in terms of public health issues related to air and water pollution, along with land use shifts that adversely impact the local communities.

34. **Public Health Cost of Thar Coal pollution:** An independent study on the air pollution due to Thar coal mining and power plant operation shows that upto 100,000 people can be adversely affected and 29,000 could die due to air pollution related causes over the 30-year operating life of the plant. Author LauriMyllyvirta of the Center for Research on Energy and Clean Air (CREA), had previously conducted research in the European Union and South Africa, and noted that these plants will be the largest air pollutant of CO2 and mercury in South Asia. The report notes that "Other health impacts include 40,000 asthma emergency room visits, 19,900 new cases of asthma in children, 32,000 preterm births, 20 million days of work absence (sick leave) and 57,000 years lived with disability related to chronic obstructive pulmonary disease, diabetes and stroke." The move towards 'indigenous' coal, it seems, comes at the high cost of local Thari peoples. [13]

35. **Coal makes water toxic:** The dewatering from the Thar coal mines has already been reported to adversely impact groundwater and surface water reservoirs in Thar. Expert analysis suggests that diffusion of toxic water from the Gorano dam and DukarChaou reservoir is causing health problems among nearby communities. Future dumping of coal-ash infused wastewater from the power plants will further threaten local populations. These are, once again, high costs that have not been included in the 'least cost' tariff calculation of IGCEP 2022-31.[14]

36. **Coal will add to water conflict:** Research by Austrian author Paul Winn of the Hydrological Consulting points to the high water demands of coal, and the likelihood of Thar coal exacerbating the water conflict in the lower riparian province of Sindh. As per the study, the water deficit between maximum mine dewatering rates and raw water demands of all power plants operating at 75% load is about 1000 billion liter per year (GLpa), increasing to about 150 GLpa after 25 years of mining. This means that the deficit will need to be met by diversion of water from the Indus Basin Irrigation System. The province of Sindh, already vulnerable to water scarcity, will suffer the social, economic, and political consequences of this new water conflict.

37. **The 'circular debt' of water at Thar Coal:** One of the central rationales behind the shift to 'indigenous' coal is that it does away with the need for importing foreign fuel. However, this is based on the entirely faulty premise that the functioning of a coal power plant requires merely coal as an input. As demonstrated in the previous comment, the water needs of Thar coal are immense. These will not only likely to cause conflict, but will likely cause lack of provision of water due to general water scarcity issues. In this case, the coal power plants will not function, and Pakistan will need to turn back to the imported option, thus perpetuating the very cycle of circular debt that this shift is designed to avoid.

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[13] Myllyvirta, L. (2020). *Air quality, health and toxic impacts of the proposed coal mining and power cluster in Thar, Pakistan*. Centre for Research on Energy and Clean Air. https://energyandcleanair.org/wp/wp-content/uploads/2020/05/Thar-Coal-Cluster-Case-Study_Pakistan.pdf

[14] 'Tharis are forced to consume toxic water.' (2022, March 26). *DAWN.COM*. https://www.dawn.com/news/1681795

38. **Land Problems for Local Thari people**: If IGCEP plans are considerate of the political constraints, then it must attend to the political demands of the communities that are directly impacted by these projects. In the case of Thar, the study of land acquisition and resettlement paints a woeful picture. Not only are Thari communities getting insufficient compensation, facing pollution and water shortages, they are also facing massive land use shifts. In particular, their historic and traditional rights to large swaths of grazing land, locally known as *gowchar*, is being ignored by the private companies and government alike. These issues have been well documented through detailed on the ground studies, like the 2022 study, "Coal Rush: The Impacts of Coal Power Generation on Tharis Land Rights' '.[15] This is an alarming trend, and must be addressed in the cost calculations of the shift to 'indigenous' coal.

39. **Proper Coal Costing Is Needed:** The troubling thing about these costs is not that we don't know about these. There's plenty of scientific studies, economic analysis, and costing methodologies on all the social, economic, environmental, and public health costs of coal. We have also identified several studies specific to Thar coal mines and power plants. The troubling thing is that NTDC, NEPRA and other relevant bodies continue to ignore these costs. These costs must be included in all tariff calculations, with the best, average and worst case scenarios considered.

The Policy of Ignoring Communities

40. **Political constraints as 'elite politics?:** The IGCEP 2022-31 clearly states that power planning seeks least cost solutions within certain constraints, including *political* constraints. We welcome this inclusion and attention to politics, as this gives a way for communities to voice their grievances. However, when we look at the projects committed, we can clearly see that the concerns of adversely affected communities are not addressed. Will NTDC clarify what it means by the term 'political constraints'? Is this merely code for addressing the concerns of the political elites, establishment powerbrokers, and the financial investors?

41. **Proceduralism as a hindrance to True Costing:** The mandate of true cost can only be met when it is carried out honestly, with good intentions and sound execution. However, we are troubled by our various interactions with NTDC, NEPRA, and other policy officials, whe, we ask for true costs of these projects. We are told that there are procedures and regulations in place for addressing the 'social and environmental impact' of different projects, and that it is not in the mandate of IGCEP to include these costs. Further, we are assured that the world's best consultants and experts develop these plans. There's a long history of dismissing people's concerns about the harms of the projects, as development experts, policy makers, and international investors externalize the true environmental and social costs without effective participation, informed consent, and free and inclusive consultations with the local and affected communities. Hiding behind such proceduralism is not the way to go.

42. **Old lessons forgotten?** It also seems that much of the historic work done by activists, communities, and academics is sidelined or ignored. A case in point is the recommendations by the World Commission on Dams on the social and environmental impact of large dams. These

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[15] Kamal, A., Moulvi, Z., Lashari, A., Hamirani, A., &Rafe, A. (2022). *Coal Rush: The impacts of coal power generation on Tharis land rights* (Research Study). Rural Development Policy Institute.https://acjce.com/wp-content/uploads/2021/09/Research-Study-Coal-rush-The-impacts-of-coal-power-generation-on-Tharis-land-rights.pdf

costs are systematically excluded from the financial calculation. In a recent report by the World Bank, it is noted that the environmental and social costs of large infrastructure projects are systematically ignored, and often excluded from the scoping studies of these projects.[16] Despite recommendations of rigorous analysis and establishing principles like Free Prior and Informed Consent, the planners in the power sector have systematically fallen short. While we write these comments, we are aware of the long history of engagement between communities adversely impacted by these projects on all formal and informal arenas of contestation. It seems though that the powers that be ignore all the lessons learnt from all the hard work, and return to business as usual

Our Recommendations and Demands:

43. We take this opportunity to register our reservations about the planned dependence on hydropower despite its numerous problems. Pakistan's shift to hydropower signals a number of problems. The proposed hydropower projects will have huge economic cost overruns, will cause environmental damage, are unsuitable for the climate and seismic conditions, and will have adverse social and economic consequences for lower riparian groups, particularly the communities of land and water users in Sindh, the Indus Delta, and the riverine communities. The 'fuel' of hydropower, water, is a scarce and public good that is already severely taxed. By adding more hydropower without considering those with existing legal and established claims on water use, the IGCEP 2022-31 indicates a plan that is likely to increase water conflict in Pakistan. The true cost of hydropower, some of which is highlighted in this brief comment, is huge. It is incumbent upon NEPRA, NTDC and other responsible bodies to take into account all these various costs.

44. The hydropower commitments of IGCEP 2022-31 seem to neither consider the rapidly changing climatic conditions, nor the existing socio-hydrological realities of Pakistan's river systems and the millions dependent on the vast mosaic of healthy river ecosystems. These projects will lock us into costly, technically unsound, environmentally destructive, and politically charged projects. The planners also seem to have ignored what's happening across the globe. Thousands of dams have already been removed in the US and Europe in the past several decades, after careful reflection on their economic, social, and ecological costs. Pakistan must not repeat these mistakes and commit billions of US dollars in inefficient and disruptive energy systems.

45. The costs of shift to 'indigenous coal' are also numerous, and calculable. The NTDC must ask the relevant departments for proper cost estimations, so these can be included in the overall tariff calculations, and the various economic models that tout this shift to 'indigenous' coal as a net positive.

46. Following international best practice as established by the World Commission on Dams Report of 2000, and insights from subsequent research, all alternative options to a new large hydropower plant should be considered. This includes but is not limited to: underwater storage (on the model of 'water banking' in the US West), solar power, tidal power, wind power, micro-hydel, and controlling inefficient and consumption of water. Wind and Solar offer the greatest potential and must be prioritized instead of costly hydropower.

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[16] Young, W. J., Anwar, A., Bhatti, T., Borgomeo, E., Davies, S., Garthwaite III, W. R., Gilmont, E. M., Leb, C., Lytton, L., Makin, I., & Saeed, B. (2019). *Pakistan: Getting More from Water*. World Bank.https://openknowledge.worldbank.org/handle/10986/31160

47. The government must be prepared to ensure substantial participation of a broad range of stakeholders in the planning process. This includes not only credentialed planners and politicians, but direct representatives from communities that are impacted by factors including but not limited to: flooding, resettlement, fluctuation of flows downstream, electrification, and changes in transport network. To ensure substantial and meaningful participation, is the government prepared to circulate (along with translation into local languages) all relevant planning and socio-environmental impact statements with all stakeholders in a timely fashion?

48. Is the government prepared to develop a comprehensive water strategy that does not reduce the Indus to its potential hydro-energy? A wise, efficient, and responsible government policy to Indus waters must integrate energy policy with other domains, including but not limited to: agrarian policy, trade policy, livelihood stability, conservation, heritage, constructive federation building, friendly international relations, and long and medium-range planning for wise use of Pakistan's natural resources.

49. Some of the concrete steps that can be immediately taken are:

    a. Release all PC1s of the projects, so these can be independently evaluated.

    b. Release details on the methodology used for cost-calculations, so that gaps in these methodologies can be identified.

    c. Increase the scope of 'costing' methodologies to include long-term, recurring, and cumulative costs - such as the impact of upstream hydro projects on downstream and deltaic communities.

    d. Release information on how the competing demands on scarce resources such as water for hydropower, water for coal, water for agriculture, and water for urban supply are being met.

    e. Conduct detailed study of the air and water pollutants in all projects, with effective monitoring and public sharing of the data.

    f. Institutionalize the best practice of Free Prior and Informed Consent.

    g. Disseminate ALL project related social, environmental, and economic impact assessment in local languages.

50. We expect that NEPRA, NTDC, and other government bodies will take our intervention seriously. We expect responses to our concerns, in particular to our specific points regarding the overlooked and ignored costs, climatic and seismic risk calculations, estimation of social and environmental costs, the exacerbation of climate change in coastal areas, and the costs of increased water conflict in the country.

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19/10/22
c. Chairman
- m(M&E)(O)
- m(Lic)(T)

KE

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Mr. Syed Safeer Hussain,
Registrar, NEPRA
NEPRA Tower, Attaturk Avenue (East),
G-5/1,
Islamabad.

Ref No. BD/MZ/NEPRA-0913/2022-1810
October 18, 2022

Subject: **Comments on Indicative Generation Capacity Expansion Plan 2022-2031**

Dear Sir,

This with reference to NEPRA letter No. NEPRA/DG(Lic)/LAT-01/18675-33 dated September 27, 2022 soliciting stakeholder comments on the Indicative Generation Capacity Expansion Plan 2022-31 submitted by the National Transmission and Despatch Company Limited.

In this regard, please find our comments enclosed as "Annexure A" to this letter.

Sincerely,

Mudassir Zuberi
Head of Business Development

Encl: Annexure A

REGISTRAR OFFICE
Diary No: 10900
Date: 19-10-2022

KE House, 39-B, Sunset Boulevard, Phase-II, Defence Housing Authority, Karachi
www.ke.com.pk 92-21-3263-7133, 92-21-3870-9132, UAN: 111-537-211

Annexure A
Letter Ref No. BD/MZ/NEPRA-0913/2022-1810
October 18, 2022

Comments on Indicative Generation Capacity Expansion Plan 2022-31

The preparation of Indicative Generation Capacity Expansion Plan 2022-31 ("IGCEP 2022-31") is an important step towards proactive planning for future electricity needs and security of supply in context of the local power sector as planning oversights from the past have already and continue to cost the sector heavily. Therefore, we appreciate the efforts of NTDC and relevant stakeholders in preparation of the IGCEP 2022-31.

Further, with respect to the draft IGCEP 2022-31, we would like to submit the following observations / comments for consideration, which we understand would enable a more integrated approach and yield better results in the long-term.

a) Clarification on recently announced 10,000 MW Solar Energy Project by the Government of Pakistan

As a measure to move towards green energy and discourage the use of costly fuel for electricity generation, based on news reports, the Government of Pakistan (GoP) recently announced 10,000 MW of solar projects. In this regard, KE requests that clarification be provided whether these planned solar additions have been accounted for in the draft IGCEP 2022-31.

b) Transmission Network Planning

The draft IGCEP 2022-31 focuses on generation cost optimization with a view on the target fuel mix, however, it does not take into consideration for transmission constraints and the resultant impact of Transmission cost (if any) in the least cost evaluation for generation projects. Here, it is also important to highlight that as part of the NEPRA approved IGCEP 2021-30, NTDC had acknowledged that to ensure true least cost principle, NTDC is obligated to prepare TSEP along with IGCEP for submission to NEPRA.

Therefore, it is submitted that IGCEP should be prepared in consolidation with the TSEP, as despite surplus capacity, due to transmission system constraints and congestions, smooth and reliable supply of power is adversely impacted and the same may also have planning and operational implications.

c) Seasonal & Climatic Variations in Hydel Generation

Out of the total projected generation mix in 2031, hydel accounts for 39%. We understand that the future Hydel generation is based on historical water flows, however, considering the seasonal & climatic impact on hydel as was also witnessed in last two peak summer seasons, the water flows are expected to be different compared to historical parameters going forward.

Therefore, it is recommended that impact assessment should be done to analyze the difference in hydel patterns and power demand patterns so that necessary contingencies are in place to ensure reliability of supply to the consumer.

d) Delay in completion of Hydro Power Projects

Development of public sector hydro power projects is significantly dependent upon availability of Government funds. If the projects considered in the draft IGCEP 2022-31 are not completed as per their stipulated timelines, the power supply situation will be different from what is demonstrated in the current draft IGCEP 2022-31.

Hence, it is recommended that a scenario incorporating any expected delays in timelines may also be incorporated in the IGCEP.

e) Retirement of low-BTU Indigenous gas-based plants

Retirement of around 800MW of indigenous gas-based plants (Liberty and Uch), has been linked with expiry of their PPA. Based on available data, in last 5 years, gross efficiency of Uch has been around 50% whereas gross efficiency of Liberty has been around 41%.

Considering their efficiency and that these plants are operated on indigenous gas supply from specific low-BTU gas fields and are high on the Economic Merit Order (EMO), the retirement of these plants should be based on techno-commercial analysis and availability of gas for these projects rather than on expiry of their PPA only.

f) Fuel 'Take or Pay' Consideration

In the draft IGCEP 2022- 31 'Take or Pay' contractual obligations are considered only for Imported Coal and Low Btu Gas projects on a minimum annual despatch of 50%. The projects considered for 'Take or Pay' are as follows:

- **Existing imported coal-based power projects** (Sahiwal, China HUBCO & Port Qasim),
- **Low Btu gas-based** projects (Uch-II, Engro and Foundation)

We would request that existing 'Take or Pay' fuel commitments on plants in KE fleet (i.e. BQPS-III and SNPC) should also be considered in the IGCEP.

Moreover, it is also recommended that 'Take or Pay' fuel commitments need to be considered for all future base load projects (i.e. Local Coal, RLNG) that would have fuel procurement considerations considering the depleting indigenous gas reserves and moratorium on coal globally due to carbon targets and climate change.

g) Fuel Price for local coal-based project

Section 5.2 of draft IGCEP 2022-31 mentions the following assumption with respect to candidate local coal-based projects:

"For candidate local coal-based projects, the fixed fuel cost component (FFCC) of 11.2 $/Ton (71.821 $/kW-year) and fuel price of 9.97 $/Ton (0.88 $/GJ) have been considered as per TCEB determination of 2020 pertaining to Thar Block-II at 30.8 MTPA."

However, it is requested to reconfirm the basis of these assumptions and also disclose sources for the same.

h) KE integration in IGCEP

In the draft IGCEP 2022-31, timelines for KE projects are inconsistent from KE submissions. Accordingly, it is requested that the timelines as submitted by KE be considered.

Furthermore, we would also like to highlight that since the data compilation exercise for draft IGCEP 2022-31 was conducted in March 2022, certain information submitted by KE for IGCEP has been modified including but not limited to extension in supply from Tapal and Gul Ahmed which have now requested two-year extension till 2024 and have filed tariff petition accordingly.

Registrar
DG (Licensing)

[redacted]

LSG HYDRO
POWER LIMITED

Office 29, 3rd Floor, Executive Complex, G-8 Markaz, Islamabad Pakistan
Tel: +92 51 8435288
http://www.lsg-hydro.com

Reference no: LSGHPP-NEPRA/IGCEP-001KL
Date: October 13rd, 2022

18-10-2022

Mr. Tauseef H. Farooqi
Chairman
National Electric Power Regulatory Authority
NEPRA Tower Attaturk Avenue, Sector G-5/1,
Islamabad, Pakistan
Tele: +92 51 9210215, Email: info@nepra.org.pk

Subject	**Comments on Indicative Generation Capacity Expansion Plan 2022-2031 (IGCEP 2022)**
Reference	**letter No: Nepra/DG (Lie)/LAT-01/18675-33**

Dear Mr. Farooqi,

Korea Hydro & Nuclear Power Co., Ltd. (KHNP) is the largest state-owned electricity generation company in the Republic of Korea, with total generation output of over 28,500MW. KHNP supplies more than 30% of the country's total electricity consumption and has been delivering various energy projects around the globe. It is developing a 470MW Lower Spat Gah Hydro Power Project ("LSG") and a 450MW Athmuqam Hydro Power Project ("AHP") in Pakistan.

The letter of Intent (LOI) for the LSG was issued by Pakhtunkhwa Energy Development Organization (the "PEDO") to KHNP on June 29, 2021, under KPK Hydropower Policy 2016. The LSG is being implemented through a special purpose company named LSG Hydro Power Limited (the "Company"), which is currently a wholly owned subsidiary of KHNP. A feasibility study on the LSG was conducted by AFRY, a renowned global engineering company. In August 2022, a Panel of Experts (the "POE") convened by the PEDO validated the results of the feasibility study. The Company plans to pursue the LSG while complying with National Electric Power Regulatory Authority (the "NEPRA") Licensing Procedure Regulations, 2021.

NEPRA has sought comments on the draft IGCEP 2022 through a notice published in national newspapers on September 27, 2022. KHNP has reviewed the initial draft of the IGCEP 2022 and would like to put forward the following submissions for consideration by the Authority.

During the determination of IGCEP 2020-30, the Authority emphasised the inclusion of LSG in the upcoming iteration of the IGCEP. The Company provided the raw data available at the time of the IGCEP 2022 proforma in December 2021. Since then, the functional specifications of the LSG have changed following the input from POE and further optimisation by AFRY. The table below demonstrates the comparative specifications of the LSG, as provided in IGCEP proforma and approved by the POE.

CHAIRMAN
Dy No. 7159
Date: 13/10/2022

REGISTRAR OFFICE
Diary No. 10822
Date: 18-10-2022

Category	IGCEP-2022 Draft	POE Approved
Annual Energy (GWh)	1,898	1,925
Economic Life (Years)	30	50
Project Cost (Mil USD)	1,131	1,085
Capacity (MW)	496	470

The annual energy, cost and economic life have enhanced in the approved feasibility study of the LSG, proving improved economic and financial feasibility. We are convinced that if the verified results of the LSG are reflected in the IGCEP classification, the project could be included in the Optimised Projects list. Therefore, we kindly request NEPRA to direct the National Transmission & Despatch Company (the "NTDC") to consider the updated input of the LSG to test the viability of the project as an Optimised Project.

In IGCEP 2022, for evaluation of the annualised cost of hydropower projects, the economic life was assumed to range between 30 and 100. Previous versions of the IGCEP assumed that all hydropower projects would have an economic life of 50 years. The project's economic life impacts the overall annualised cost and may provide misleading results for the optimisation of the projects. A rerun of the IGCEP 2022 should be conducted to demonstrate a comparable analysis of all candidate projects.

The Company intends to acquire a Letter of Support (LOS) by June 2023. To that end, it plans to request NEPRA to issue a generation license within the year while complying with relevant laws and regulations. Also, we wish to complete the tariff petition for the feasibility study stage by the first half of 2023.

We ask for NEPRA's active support so the Company can receive the LOS in a timely manner.

Thanks & Regards.

LSG HYDRO POWER LIMITED
LSG

Sangwoo Kim,
Chief Executive Officer,
LSG Hydro Power Limited.

CC:
1. MD, National Transmission & Despatch Company, Lahore.
2. Secretary, Energy & Power GoKPK, Peshawar.
3. CEO, Pakhtunkhwa Energy Development Organization, Peshawar.
4. MD, Private Power and Infrastructure Board, Islamabad.

Pakistan Renewable Energy Coalition
TOGETHER FOR A RENEWABLE POWERED PAKISTAN

The Chairman
National Electric Power Regulatory Authority
NEPRA Tower, Ataturk Avenue (East)
G-5/1, Islamabad

Dated: Oct 14, 2022

Subject: Comments on the IGCEP 2022-31 by Pakistan Renewable Energy Coalition

Dear Sir/Madam:

Attached herewith are comments from the Pakistan Renewable Energy Coalition, in response to the IGCEP 2022 prepared by NTDC for review and approval of NEPRA and the NEPRA Public Hearing Notice, inviting comments in writing and participation from all stakeholders.

The RE Coalition is a group of allied organizations and individuals working to assist in accelerating the growth of renewable energy in Pakistan's energy mix and foster implementation of goals set within the Alternate and Renewable Energy Policy 2019, Paris Climate Agreement and updated Nationally Determined Contributions (NDCs) of Pakistan.

We hope that these comments and suggestions are taken up by NEPRA in the public hearing to be held on 19.10.2022 and are incorporated in any further revisions or iterations of the IGCEP 2030.

Best Regards,

Mustafa Amjad

On behalf of Pakistan Renewable Energy Coalition,
Muhammad Mustafa Amjad

REGISTRAR OFFICE
Diary No. 1026
Date: 18-10-2022

The following organizations as a part of the RE coalition endorse the comments that follow this letter.

1	Renewables First	RE RENEWABLES FIRST
2	Policy Research Institute for Equitable Development	PRIED Policy Research Institute for Equitable Development
3	Sustainable Development Policy Institute	SDPI
4	Indus Consortium	Indus Consortium
6	The Knowledge Forum	THE KNOWLEDGE FORUM

Comments on the IGCEP 2022-31
Submitted by the Renewable Energy Coalition
Dated: Oct 14th 2022

The latest version of the IGCEP shows notable improvements over the previous one. We are happy to note that several of the comments and concerns of our partner organizations related to last year's IGCEP such as following through on ARE 2019 targets and inclusion of distributed RE generation in planning document have been addressed in this current version. However, the current version of IGCEP involves various assumptions and constraints which prevent it from achieving the true and optimal potential of renewable energy in national electricity generation.

1. Transparency & Open Access of IGCEP Model Input Data

   The IGCEP starts with the acknowledgement that the document "relies extensively on the input data provided by a wide range of entities". This data, provided by various institutions, has a significant role in defining the overall direction and outputs of the planning process. It is therefore pertinent that the data used in this manner should be made publicly available on the relevant websites along with rationale and methodologies to ensure transparency and public scrutiny. Without the public availability of such data, the content of IGCEP remains shrouded in mystery and presents a major hurdle to independent attempts to verify and improve the planning process by research institutions and think tanks. We request, therefore, that the data used in IGCEP along with its collection and calculation methodologies should be made publicly available on the websites of concerned institutions.

2. Missing Information on Parameters Assumed for Solar and Wind

   In section 5.13 table 5-6, parameters for candidate solar and wind projects have been provided. However, no rationale or costing methodology has been given. It is further unclear how the annualized cost of energy comes out to be the same for all three technologies i.e. solar utility, solar feeder and wind at 4 cents/kWh. It is also unclear what impact the scale of the project may have on these parameters. Therefore we request that the rationale and costing methodology for these parameters be incorporated into the IGCEP for further clarity of relevant stakeholders.

3. Missing Information on Calculation Methodology for Net Metering

   In section 5.9.1 table 5-4, a total of 4,320 MW of net metering (480 MW each year from July 2022 onwards) has been listed as committed capacity. It is mentioned that the figures for the same have been provided by the AEDB. However, no rationale or costing methodology has been given. The absence of this information raises concerns regarding the reliability of these figures and how these targets may be achieved in a timely manner by the concerned authorities. Such concerns are even more pertinent in the light of recent reduction in net metering payback rates by NEPRA and the rising costs of exchange rates which will inevitably have an impact on consumer confidence and technology adoption in the coming years. On the other hand, we may also question why a fixed number has been chosen for net metering additions instead of yearly increase based on power demand and market growth? To address these confusions, we request that the rationale and costing methodology for these net metering targets be incorporated into the IGCEP to insure transparency and reliability in capacity planning.

4. Missing Transmission System Expansion Plan and Extension of KAPCO B-I&II

In section 5.2 Assumptions of IGCEP, it is stated that a minimum dispatch of 500 MW from KAPCO CCPP (Block I & II) has been provided in the months of May to September till the year 2025 beyond its PPA expiry of Oct 2022. The reason for this extension has been cited as network requirements and constraints. It has also been mentioned that this extension will be assessed in the ongoing Transmission System Expansion Plan (TSEP). However, no such transmission plan appears to be in sight and no tentative date for its publication has been provided. Moreover, the disclaimer to the current IGCEP states that "the IGCEP is exclusive of any costs relating to power system evacuation and transmission system expansion". These costs shall only be allocated "following the approval of the transmission system expansion cost allocation criteria by CCI". The extension of KAPCO beyond its PPA therefore raises the question as to why has it been considered in IGCEP on transmission related reasons despite the fact that KAPCO has been allowed 485 days of force majeure events due to fuel shortages between June 2021 and Oct 2022, the highest number of days in all national plants. It is also relevant to note that the average price of energy purchased from KAPCO during fiscal year 2021-22 was 42.51 Rs/kWh exclusive of capacity payments as per the State of Industry Report 2022. The capacity payments issued to KAPCO during the same year add another 1.4 billion to the payment. Moreover, due to the Build Operate Own (BOO) basis, the land and other infrastructure associated with KAPCO remains at the disposal of the IPP which is a further loss to the national exchequer. The TSEP related issues on the basis of which extension to KAPCO has been granted make no sense when we consider the fact that NTDC is unwilling to extend the same consideration to massive transmission infrastructure costs incurred in large hydro projects in the north. There is thus a contradiction in IGCEP's treatment of KAPCO and large hydro. This is further problematic when no further details on the particular nature of grid constraints around KAPCO have been given and no attempts have been made to explore alternative fuels or technologies by the planning agencies. In light of all the above arguments, we request that the extension of KAPCO B-I&II be made subject to TSEP assessment and the completion of TSEP be expedited for fulfillment of the optimized generation project in its true form and spirit.

5. Missing Rationale for Scenario V Addition of 1320 MW Local Coal in Years 2027 and 2030 as Committed

The IGCEP 2022-31 considers 1320 MW of local coal in the year 2027 and 2030 each (cumulative 2640 MW) as committed capacity. However, it is not clear why this scenario has been carried out when the base case scenario has already optimized local coal at a maximum of 990 MW in the year 2027. Moreover, as table E3 makes it perfectly clear, the addition of local coal incurs a cost of $53.06 billion, much higher than the $52.93 billion of the base case. Therefore, we request that a justification for inclusion of this needless scenario in the current version of IGCEP be provided or alternatively, the scenario be excluded from the report.

6. Circumventing the IGCEP: G2G Projects and the 10 GW Initiative

Section 1.6 of the document lays out the purpose of the IGCEP in clear words as follows: "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". It is therefore pertinent to ask how the initiative taken by Ministry of Energy, power division to replace 10,000 MW of fossil fuel based generation with solar PV fits with the planning of IGCEP. Given that such huge fast track investments can have major financial implications for the power sector and the economy at large, it is important for such investments to be a part of IGCEP scenarios in order to ascertain their true cost in the short and long term. Moreover, the assumptions of the IGCEP include provisions for G2G projects to be added as committed inputs. As previous iterations of IGCEP have shown, projects added in the committed category are removed from the least cost considerations and discussion altogether, even if they run contrary to the purpose of IGCEP. It is important to ask, why does IGCEP allow provisions for committed projects through G2G channel to be added indefinitely into the future for projects which have not even been conceptualized yet and when added, will be able to bypass the entire optimization process? Whether it is the case of 10 GW additions proposed by the Ministry of Energy (Power Division) or the future G2G projects, why does IGCEP, being the master national plan of power sector, accept raw data and inputs from outside instead of proposing such additions itself based on its own vision and optimization? Even if IGCEP is forced to accept such inputs, why are such projects treated as committed instead of being treated as possible scenarios to ascertain their true financial costs? In order to make the IGCEP inclusive and reflective of ground realities, we request that a financial analysis of 10 GW solar should be made a part of scenarios to obtain clarity and build a rationale behind such a huge amount of power addition to the grid. We also request that further clarification is provided with regards to which fossil fuel based plants are expected to be replaced by the said addition given the fact that many of the IPPs are nearing their expiry term anyway and their replacement may not prove worthwhile at this stage. Moreover, we also ask that rationale be provided for including G2G projects under the heading of committed projects since such practices clearly bypass the IGCEP process and are also likely to discourage private investment in a soon to be open and competitive market.

7. Wind & Solar Constraints and a True Unconstrained Model

In scenario IV of the IGCEP 2022-31, an unconstrained model of solar and wind has been carried out which has resulted in 644 MW of additional wind while 1295 MW of solar PV has been reduced. However, the unconstrained model begs the question: why have the solar and wind constraints been applied to the base scenario in the first place? On what basis, if not least cost, are the respective shares of wind and solar being limited? We request that further clarity and justification be provided behind the said constraints in the base case.

It can also be noted that no scenario of IGCEP provides insight into the costs of going through with the committed capacity additions. As per the State of the Industry Report 2022, capacity payments accruing up to Rs. 721 billion were meted by CPPA-G in the FY 2021-22 alone even though the utilization factor of Take or Pay thermal power plants in the CPPA-G system was only 46% and that of WAPDA hydropower plants was limited to 39%. To make the matters worse, payments worth Rs. 41.7 billion have been made in the same year as Part Load Adjustment Charges. Due to persisting shortage of RLNG, low pressures of pipeline quality gas and sky-rocketing prices of RFO/HSD, it is likely that partial utilization of available capacity will continue. In these circumstances, bringing further IPPs online such as 1263 MW Trimmu 660 MW Jamshoro which operate on RLNG, HSD/RFO or imported coal seems counter-productive. Refusing to reconsider these investments is a clear case of path dependency which has been acknowledged by NEPRA yet termed the only "pragmatic" option available. We only ask that at the very least, scenarios should be added in IGCEP which assess the true nature of these path dependencies to ascertain whether going through with past investments is still truly the only course of action? What are the additional costs of staying on these paths? What are the costs of replacement and re-negotiation of contracts? Knowing the answer to such questions can help the policy makers strategize with more clarity. Including such scenarios will also make provide the IGCEP with "a truly unconstrained scenario" which the current version does not have.

8. Modeling K-Electric and NTDC as Two Separate Systems

Section 1.2 of IGCEP mentions that NTDC is responsible for power system planning of the entire country. Therefore the current version of IGCEP has modeled both the NTDC and K-Electric systems by connecting them with a tie line having a fixed export of 1,100 MW till June 2024 and 2,050 MW till 2031. The supply from NTDC is one of the cheapest sources of electricity available to K-Electric and treated by the utility company as a must-run. This is also evident from the fact that IGCEP readily optimized 990 MW of local coal for the K-Electric system but not for the NTDC system. Therefore, when the amount of electricity available through NTDC-KE tie line has been fixed, any optimization carried out henceforth cannot be treated as applicable to the entire country. Rather, the optimization carried out in this manner can only be called least cost with respect to KE's own generation. However, this defies the mandate of IGCEP to optimize and plan the power system of the country as a whole. Failure to do which raises questions over the optimization of 82.25 MW Turtonas Uzghor KE Hydro in 2029 and 990 MW KE Local Coal in 2027 by the current IGCEP. It is important to ask why IGCEP has not allowed the tie line between the two systems to be treated as variable by PLEXOS to ascertain whether the said projects are truly least cost with respect to the entire system? It is also important to note that the Turtonas Uzghor Hydro project is located in the north, far from Karachi and requires wheeling across the entire country. Providing additional electricity through the said tie line may have been a better approach with respect to both the generation and transmission costs. We request that the relevant authorities reconsider the nature of the NTDC-KE tie line in order to truly optimize the generation of the entire country.

9. Transition of Gwadar to Local Coal

In IGCEP 2021-30, the Gwadar Coal-Fired Power Project has been considered an imported coal project. However, IGCEP 2022-31 has treated the same as local coal based on inputs from the local executing agency, the PPIB. Since the change in fuel is likely to have financial implications, we request that this change be made a part of IGCEP calculations in order to assess the relief or loss this transition is likely to contribute in the national electricity mix. Moreover, we request that a comparative analysis should also be provided between the cost of continuing the said plant on local coal and securing electricity for the area through alternative distributed generation options such as hybrid or standalone RE.

10. Cost and Schedule Overruns in Hydropower and Effects of Climate Change

According to a recent IEEFA report[1], nearly 1[illegible] GW of hydropower capacity is expected to come online in Pakistan by 2030, out of which only 51% has achieved financial closure and only 39% has begun physical construction as of September 2022. The fact sheet also mentions that almost 70% of the pipeline capacity requires partial or complete funding by either WAPDA or provincial government bodies. According to IEEFA estimates, only 15% of the planned capacity is expected to come online in time whereas cost overruns could go up from the current USD 31 billion to USD 49-61 billion. Delays in pipeline realization are likely to increase power outages and load shedding in the country, prompting a switch back to fossil-fuel power to bridge the shortage. Moreover, Pakistan and the government's hydropower development wing have been downgraded by all three prominent credit rating agencies: Moody's, Fitch and S&P, increasing the likelihood of delay in implementation of hydropower. The hydropower pipeline is also becoming vulnerable to extreme weather patterns and climate change, the effects of which have been seen across the globe in Norway, France and China in the form of drying up of rivers and lower reservoir levels. In Pakistan too, the early onset of summers saw record breaking temperatures and low reservoir levels.

Information related to hydropower costing has been provided in the current IGCEP in Annexure B-3 and B-5 with capital cost and its local and foreign components provided. However, in light of the IEEFA findings above, it is pertinent to ask that IGCEP provide more clarity and detail on cost mismatches in light of historical data and account for costing of renovation/refurbishing, schedule overruns, uncertainty in indexation and contingencies such as experienced in the case of Neelum-Jhelum and Mohmand Dam. We request that all such cost considerations should be included and made publicly available to provide further confidence to stakeholders in the national power planning processes.

11. Hybrid Projects and Battery Storage

As acknowledged in section 7.2.1 hybridization of variable renewable energy projects – combination of solar PV and wind with battery storage – has beneficial impacts on the grid and generation. Not only are solar and wind complement each other, along with battery solutions they fluctuate less and provide continuous supply of electricity to the grid. The need for enabling environment and technical studies has also been mentioned in the same section. It should be noted, however, that a study on solar and wind hybrid projects in Pakistan has already been launched by GIZ as of September 2021. We request that given

[1] Isaac, Haneea. 2022. Fact Sheet: Pakistan's vast hydropower pipeline at risk of not being materialized https://ieefa.org/resources/fact-sheet-pakistans-vast-hydropower-pipeline-risk-not-being-materialized

the urgency and significance of hybrid solutions, as emphasized by the IGCEP itself, should be incorporated into the revised version of IGCEP. Moreover, given their importance for the future of electricity, battery aided wind and solar hybrid projects should be facilitated under the framework of ARE policy to reap their benefits in future auctions and to ensure their accelerated deployment at large scales.

12. Demand Side Management of Peaks

Section 4.4.1 of the IGCEP addresses the topic of demand side management and mentions that a 2190 GWh quantum of energy efficiency target provided by NEECA has been assumed to be met and subtracted from all future year targets. However, IGCEP does not address the issue of peak demand, management of which can result in the highest cost savings in the national grid as well as reduce transmission system load. In light of the huge implications involved, we request that calculations related to potential cost savings through practices of peak shaving peak shifting and peak management with alternative energy sources should also be made part of the report.

13. Optimization of Generation Projects post TSEP-related Costs

The disclaimer to the IGCEP duly mentions that the plan is "exclusive of any costs relating to power system evacuation and transmission system expansion for optimized generation project". These costs "shall be allocated to the optimized generation project following the approval of the transmission system expansion cost allocation criteria by CCI". Only after such allocation has taken place, the final and "true" version of the optimized generation project will be available. The current selection and ranking of projects, therefore, does not reflect the truly optimized and integrated model. It has been mentioned that the purpose of the IGCEP is to "identify generation additions...through optimal use of all available generation resources" and ensure that the "demand in the system is adequately met by adding generation capacity on least cost basis." The said goal, however, is not fulfilled completely until the final optimized generation project has been made available and its findings have been incorporated into the master planning document. We request that further explanation should be made available regarding the exact procedure by which the final optimized model is developed and whether the IGCEP will be (or ought to be) amended in light of such a model.

14. Additional: Post-Flood and Post-IMF Conditions and Fostering New Technologies & Solutions

The current assumptions of IGCEP do not reflect the rapidly changing economic conditions of Pakistan after the advent of floods and negotiations with IMF. We request that changes

24-7-9

[illegible] reflect the same. Moreover, we also request that quantums for [illegible] [illegible] be identified and allocated in the IGCEP to encourage development [illegible] technologies. Alternative and innovative solutions for solving social-environmental [illegible] [illegible] of power demand should also be considered such as roofing with solar panels. Moreover, use of technologies such as green hydrogen and green [illegible] should also be explored.

Recommendations for the next IGCEP

Dr. Peter Meier (World Bank Economic Analysis Consultant)

1. The IGCEP is an excellent report, that uses an advanced power system planning model (PLEXOS). Based on our review of the IGECP 2021 and 2022, we have the following recommendations for the next iteration.

CASA-1000 ASSUMPTIONS:

2. These need to be more clearly defined and tied to the obligations stipulated in the CASA Project Master agreements and the PPAs. There is some unavoidable uncertainty here whether AFG will exercise its right to re-sell its CASA-1000 entitlements to Pakistan: what is important is simply that there is clarity on the assumption actually made.

3. The CASA-1000 CAPEX is sunk, and need not be considered further. Similarly, the CASA-1000 OPEX may also be considered sunk, since the corresponding charges will be recovered even if a party defaults because for the liquidated damage provisions.

4. We suggest that the next iteration defines three CASA-1000 projects: **the first (CASA-I) takes into account the explicit obligations required – i.e., subject to the fixed minimum and additional GWh stipulated in the PPAs.**

Table II.1: CASA-1000 obligations

		CASA-I	CASA-II headroom
	year	[GWh]	[GWh]
2025	1	3,759	895
2026	2	3,603	1,051
2027	3	3,595	1,059
2028	4	3,520	1,134
2029	5	3,391	1,263
2030	6	3,410	1,244
2031	7	3,410	1,244
2032	8	3,409	1,245
2033	9	3,409	1,245
2034	10	3,370	1,284
2035	11	3,340	1,314
2036	12	3,328	1,326
2037	13	3,328	1,326
2038	14	3,289	1,365
2039	15	3,240	1,414

5. As per the signed PPAs, these quantities are to be supplied in the five months May to September. This project can only be dispatched in May-September, and cannot be dispatched Oct to April. The total annual energy should be *forced* in.

6. In the financial analysis, this energy should be priced at 6.4 USc/kWh (the balance of the actual price is sunk, namely the charges to recover CAPEX and fixed O&M). In the economic analysis the price is 5.15 USc/kWh (the difference being the transit charge payable to AFG of 1.25 USc/kWh)

7. **The second is the summer headroom project (CASA-II)** that captures the "excess energy" as defined in the CASA agreements, for which the price is simply the (known) excess energy charge. It will answer the question of whether buying this excess energy is economic or not. The pricing of this energy as the same as case (1), but now the constraint is *less than or equal* to the monthly headroom as shown in Table II.1.

8. Note that the sum of excess and obligation energy is constrained by the 1300 MW capacity of the line.

9. **The third represent the off-season CASA-1000 purchases in April and October** ("CASA-III") – again priced as in CASA-I and CASA-II. In April the maximum is 936 GWh, and October 967 GWh.

THE NUMERAIRE

10. There needs to be better clarity about the price level. One assumes that all costs are at constant mid-2022 prices, but whatever it is should be expressly stated.

11. It is also unclear whether the analysis is based on economic or on financial prices. For example, the price of domestic natural gas is set by the OGRA, and is an administered *financial* price, However in an *economic* analysis, gas should be priced at its opportunity cost: which in a situation of declining supply of domestic gas, will be that of LNG.

12. If indeed the economic analysis is at 2022 constant prices, then nominal price forecasts must be deflated accordingly. For example, the CASA1000 energy charge of 5.15 USc/kWh – constant in nominal prices – must be deflated over time (so gradually declines in constant terms).

FUEL PRICE ASSUMPTIONS

13. Fuel prices are indexed into the future years "as per the Energy Information Authority Annual Energy Outlook 2022 [1](except for domestic coal & biogases where the That Coal and Energy Board tariff was applied to domestic coal and upfront tariff of biogases in 2017 applied to biogases". Table II.2 shows the indexation factors used.

Table II.2: Fuel indexation factors

Year	Furnace Oil	Local Gas / RLNG	Imported Coal	Uranium	Thar Coal	Bagasse
		Variable Price Index for Fuel Based Technologies				
2021-22	1.000	1.000	1.000	1.000	1.000	1.00
2022-23	0.961	0.936	0.992	1.003	1.001	1.00
2023-24	1.029	0.862	0.991	1.004	0.994	1.02
2024-25	1.044	0.820	0.967	1.007	1.009	1.02
2025-26	1.057	0.819	0.951	1.009	0.937	1.04
2026-27	1.089	0.841	0.950	1.012	0.951	1.04
2027-28	1.101	0.878	0.945	1.013	0.949	1.06
2028-29	1.109	0.899	0.949	1.016	0.942	1.06
2029-30	1.116	0.919	0.947	1.019	0.948	1.08
2030-31	1.137	0.931	0.946	1.020	0.935	1.08

Source: IGECP, Table 3-1.

14. These escalation factors are a mystery

- Why would Pakistan's domestic gas price escalate at the same rate as the imported LNG price?
- We have examined the report cited. The only gas price forecast is for Henry Hub. Why this would be relevant to Pakistan is unclear.
- For coal price we see only a figure for the USA average mine-mouth price. Again, this has no relevance to Asia-Pacific coal prices (Pakistan imports coal mainly from South Africa).
- The EIA forecasts are all at nominal prices.

1 This was published in March/April 2022.

- Whether the escalation factors are applied to nominal prices in this report, or adjusted for inflation, the Henry Hub prices increase slightly over time, not decrease as shown.

15. We strongly recommend that fuel price changes during the modeling period be based on an appropriate forecast by a recognized international entity that issues forecasts for globally trade fossil fuels.

16. For example, we would suggest use of the World Bank forecasts in their biannual publication Commodity Market Outlook – as shown in Exhibit 1.

17. In view of the huge disruptions following the Russian invasion of Ukraine the April 2022 forecast only covered the short term to 2024, but developments since then have made even that forecast obsolete. A new forecast is about to be issued by the Bank this month, which should be used for any additional PLEXOS runs.

Exhibit 1: Recent World Bank forecasts

Forecast of October 2021

Commodity	Unit	2019	2020	2021	2022	2023	2024	2025	2030	2035
					Forecasts					
Energy										
Coal, Australia	$/mt	77.9	60.8	140.0	120.0	90.0	86.4	82.9	67.5	55.0
Crude oil, avg	$/bbl	61.4	41.3	70.0	74.0	65.0	65.4	65.8	67.0	70.0
Natural gas, Europe	$/mmbtu	4.8	3.2	14.6	12.6	9.2	8.9	8.7	7.5	6.5
Natural gas, U.S.	$/mmbtu	2.5	2.0	4.1	4.0	3.9	3.9	3.9	4.0	4.0
Inflation indexes, 2010=100										
MUV index		99.5	98.6	100.6	102.3	104.0	105.9	107.8	118.6	118.6
% change per annum		(2.2)	(0.5)	1.6	1.7	1.7	1.6	1.6	2.0	2.0
U.S. GDP deflator		116.0	118.1	120.5	122.9	125.4	127.9	130.4	144.0	144.0
% change per annum		1.5	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Update of April 2022

Price data in nominal U.S. dollars						
Energy						
Coal, Australia	$/mt	60.8	138.1	250.0	170.0	154.7
Crude oil, Brent	$/bbl	42.3	70.4	100.0	92.0	80.0
Natural gas, Europe	$/mmbtu	3.2	16.1	34.0	25.0	22.3
Natural gas, U.S.	$/mmbtu	2.0	3.9	5.2	4.6	4.7
Liquefied natural gas, Japan	$/mmbtu	8.3	10.8	19.0	14.0	13.3

The next CMO is expected some time in late October. To be updated then.

PAKISTAN INITIATIVE ON ENERGY

Subject: **COMMENTS ON IGCEP-2022-31**

Dear Sir,

Pakistan Initiative on Energy (PIE) is a dedicated forum related to energy issues in Pakistan. After a formal review following are comments from PIE Pakistan on IGCEP 2022-31.

- There is no mention of CTBCM in IGCEP 2022-31 Report, what are the assumptions about CTBCM & which authority has considered these assumptions DISCO's or Market Operator of CTBCM model? It is mentioned that Candidate as well as committed power projects under 20 MW and connected below 132 kV (and hence, not in central dispatch) have not been considered. But there seems to be a contradiction that net metering is considered as a major contributor but CTBCM impact hasn't been considered.

- Every year 480 MW Net metered solar energy has been considered in the system, what are basis of these assumptions. If it is based on natural growth model, yearly incremental No should not be a constant figure?
- There is an increase of 95% capacity addition from Solar power as compared to last year's IGCEP report in base case scenario. What is basis of this consideration?
- In base case wind installed capacity by 2031 will be around 10% of total installed capacity. However as per NTDC Grid Code Addendum No. 1 (Revision-1) section 13, wind installed capacity should not be more than 5%. It seems that this factor has not been considered.
- Port Qasim have been given dispatch rate less than 50% in coming years. Don't they have a guaranteed dispatch rate of not less than 50%.
- GOP is going to privatize RLNG based power plants but energy dispatch rate considered is very low. What are reasons behind that and wont it impact the valuation of these plants.

Regards

PIE Pakistan.

GHCL

JAMSHORO POWER COMPANY LIMITED
(GOP OWNED CORPORATE ENTITY)

Chief Executive Officer

No. CEO/JPCL/GENCO-I/ 10274 October 18, 2022

Shakil Ahmed.
Additional Director Registrar Office,
National Electric Power Regulatory Authority
NEPRA Tower, Ataturk Avenue (East)
G-5/1, Islamabad

Fw afore (CEO) 19/X/22
- DG (Lic) input
- ADG (CT)
- SA (N&E)
- Cons. (CTBCM) - Cns. (Tech)
- m.f.
Chairman
- m (M&E/CA)
- m (Lic/T)

REGISTRAR OFFICE
Diary No: 16916
Date: 19.10.2022

SUBJECT: **NOTICE FOR SEEKING COMMENTS AND PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN (IGCEP-2022)**

NEPRA REF: NEPRA/DG (LIC)/LAT-01/18675-33 September 27, 2022

Dear Sir:

This shall respond to the Authority's afore-referred communication in respect of IGCEP-2022 prepared and submitted by NTDC for approval, requiring that JPCL provide comments before or during the public hearing scheduled to be held on 19.10.2022.

JPCL draws the attention of the Authority regarding retirement schedule of GENCOs / JPCL those plants who were decided to be shut down in Phase-II as per CCoE decision as provided in the Table 5-2 of IGCEP-2022.

We see that following plants of GENCOs / JPCL were decided to be retire in IGCEP as follows:

Power Station	Installed Capacity (MW)	Fuel Type	License Validity	PPA Validity	Retirement Year (FY) in IGCEP	Rationale in IGCEP
Jamshoro- U-1	250	RFO	**Feb 13, 2028**	**Sept 2040**	**FY 2023**	**CCoE decision**
Jamshoro- U-4	200	RFO/ GAS/ RLNG	**Feb 13, 2029**			
Total	**450**	-				

Cognizant of the fact that JPCL is fully owned by the Government of Pakistan and the fact that the Authority is seeking comments in respect of NTDC IGCEP-2022 recommendations to shutdown GENCOs/JPCL plants in the light of CCoE decision; JPCL / GENCO-I submits its comments with due deference and requests reconsideration of the retirement schedule as recommended by NTDC in IGCEP-2022 for reasons appearing herein below:

I. Retirement of GENCOs Plants in the light of CCoE decision entails legal consequences:

JPCL has been served proceedings in C.P. D-3346/2021 titled *Noor Ahmed & two others vs. Federation of Pakistan* challenging the decision to close down certain units, including Units 1,2,3 & 4 of GENCO-I. It appears from the record of the petition that the Authority has been arrayed as a respondent and listed at serial number 8. Similarly, JPCL has been listed as respondent number 11.

At present CCoE decision and all relevant orders are held in abeyance by the Honorable Sindh High Court and the matter is sub-judice at present.

JPCL has every intention of defending itself in the afore-referred proceedings by opposing the case set up by the petitioners before the Sindh High Court. To that extent, JPCL's interests are aligned with its shareholder and all authorities that oversee and/or regulate operations of JPCL or similarly placed GENCOs.

Keeping in view of this, it is requested that the recommendation of NTDC in IGCEP-2022 for the retirement of GENCOs in the light of CCoE decision may please be postponed until the matter is sub-judice.

II. Extension of Generation License and PPA of KAPCO-1 (400 MW RLNG Based) and KAPCO-2 (900 MW RLNG Based) owing to system constraints:

It is apprised that KAPCO whose PPA / License has expired on June 2021 has been recommended by NTDC up to FY 2026 owing to system constraints. Whereas 1292 MW RFO based HUBCO, operation has been recommended by NTDC up to 2027.

Whereas GENCO-1 Plants in Phase-II of CCoE decision were retained for system constraints in southern region which may be utilize up to their license term (2029) in place of HUBCO.

III. Consultancy Services for Conducting a Study to Decide Future of Operational and Non-Operational Power Plants of GENCOs:

As per directions of GOP, GHCL is in process of hiring consultancy services for conducting a study to decide future of operational and non-operational power plants of GENCOS. The tender has already been floated and opening date of tender is 08.11.2022.

Keeping in view of this, it is requested that the recommendations of NTDC in IGCEP-2022 for the retirement of GENCOs may please be postponed until the consultant conducts study to decide future of operational and non-operational power plants of GENCOS and submits report in this regard.

Therefore, the Authority is requested to reconsider the retirement schedule of GENCOs as recommended in IGCEP-2022 until the matter in the constitutional jurisdiction of the Sindh High Court in CP No. D-3346/2021 has been finally decided as well as a proper study of consultant and the report has been finally submitted to decide future of operational and non-operational strategic power plants of GENCOs keeping in view of avoiding instability of national grid.

Sincerely,

(Tanzil Rahim)
Chief Executive Officer
JPCL (GENCO-I)

Distribution:
1. MD / CEO (GHCL), OPF Building, Sector G-5/2, Islamabad.

Fw u/o 8 r (CAP) NPY/x/2/2 Chairman
- DG (Lic) - m(CH&E/CA)
Copy to - m(Lic/T)
- ADG (T)
- SA (H&E)
- Cms (Tech)
- M.F

GHC

Central Power Generation Co. Ltd.
GENCO-II. TPS GUDDU.

Office of the
Chief Executive Officer
CPGCL, GENCO-II. Guddu.
Phone 0722-679088
Fax: 0722-578328

No. CPGCL/CEO/NEPRA/22/ 9447-49

Dated: 26 / 10 / 2022

Registrar NEPRA,
NEPRA Tower. Ataturk Avenue (East),
G-5/1. Islamabad.
Phone: 051-9206500
Fax: No. 051-2600026.

Attention Mr. Shakil Ahmed, Additional Director

Subject: - **NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-2031 (IGCEP-2022)**

Ref: Letter No. NEPRA/DG (Lic)/LAT-01/18675-33 Dated September 27, 2022.

Reference is made to the subject cited NEPRA Hearing in the matter of IGCEP 2022-31 Dated 19.10.2022 and the requirement of comments from all the stack holders.

Enclosed please find herewith the requisite comments from CPGCL on the Report alongwith the enclosures as desired please.

Thanking for anticipation please.

Chief Engineer/ Technical Director
CPGCL, (GENCO-II)

Copy to:

1. Chief Executive Officer, CPGCL - TPS, Guddu.
2. Manager (MIS), CPGCL, TPS, Guddu.

CPGCL COMMENTS / OBSERVATIONS ON IGCEP REPORT 2022-31

<table>
<tr><th>Para No.</th><th>IGCEP REPORT 2022-31</th><th>CPGCL Comments</th></tr>
<tr>
<td>Page (51)
Section 5.8</td>
<td>
Para 1
<u>Retirement Of Existing Power Projects.</u>
The retirement schedule for the IGCEP 2022-31 is provided in the table5-2. For the purpose of the IGCEP, a power project stands retired either as per its PPA/EPA terms or retirement CCoE decision.
<table>
<tr><th>Sr.#</th><th>Name of power station</th><th>Installed Capacity</th><th>Retirement year(FY)</th><th>Rationale</th></tr>
<tr><td>1</td><td>Guddu-II U (5-10)</td><td>620MW</td><td>23</td><td>CCoE Decision</td></tr>
</table>
</td>
<td>
The CCoE decision dated 10-09-2020; wherein, committee decided for closer of certain power plants on different bases.
The CCoE decision and approved plan for closure of power plant was further discussed in ECC during the case No. ECC-348/32/2021 Dated 23rd September, 2021 therein the Economic Coordination Committee (ECC) constituted a committee under the chairmanship of the Secretary (Power Division) and comprising of Mr. Anwar Shaikh Senior joint secretary, Finance division and representative of the NEPRA with following Terms of Reference (TOR) regarding Plants proposed for closer by CCoE,
<ol type="i">
Justification for the closer and cost saving;
Assessment of cost incurred on the closer;
Loss of revenue due to the closure',
Broad Based Impact on the books of the Government.
Viable options for disposal of assets pertaining to those plants.

Copy of the ECC decision attached (Annex-A).
Consequence of the ECC decision cited above, GENCO Holding Company Limited (GHCL) was directed to hire an independent consultancy firm with above TOR and furnish the comprehensive report regarding the viability of the closer of certain plants in the light of the consultant recommendations for onwards submission in ECC. The consultant recommendations are yet to be received henceforth, the CCoE decision held as under review by the higher forum i.e., ECC.
Also, it is worth mentioning that 600MW CCPP TPS Guddu plant (GUDDU-II U 5-10) is sharing 400MW approx. with the national grid with more than 60 % utilization factor by the Network Operator (NPCC). The plant stands at a Merit Order No. 09 (Combined Cycle) / 14 (Open Cycle) which indicates that the plant still Generating considerably cheap electricity for the nation with paramount reliability and availability. It is not out of place to mention that the total operating cost / kWh (EPP+CPP) of the said Plant is Rs.8.55 / kWh, which is less than the levelized cost of VRE (i.e., ¢ 04/kWh).
Therefore, it is requested that retirement schedule of the Power Projects based upon the CCoE decision may be revised keeping in view the revision of CCoE decision by ECC as well as keeping in view of the plant importance and present plant performance / KPI in the best interest of Nation.
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</table>

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<tr>
<td>Page (114)
Section 5.8</td>
<td><u>Annexure B-2</u>

Cost Data of Existing, Committed and Candidate <u>Thermal Projects.</u>
<table>
<tr><th>Sr#</th><th>Project Name</th><th>Fixed O&M</th></tr>
<tr><td>12</td><td>Guddu-I U (11-13)</td><td>25.12</td></tr>
<tr><td>15</td><td>Guddu-II U (5-10)</td><td>25.12</td></tr>
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</td>
<td>Fixed O&M may be corrected as under,
<table>
<tr><th>Sr#</th><th>Project Name</th><th>Fixed O&M</th></tr>
<tr><td>12</td><td>Guddu-I U (11-13)</td><td>11.83</td></tr>
<tr><td>15</td><td>Guddu-II U (5-10)</td><td>11.83</td></tr>
</table>
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</tr>
</table>

Case No.ECC-348/32/2021 Dated: 23rd September, 2021

APPROVAL OF FINANCIAL SUPPORT TO GENCOs

DECISION

The Economic Coordination Committee (ECC) of the Cabinet considered the summary dated 10th September, 2021 submitted by the Power Division regarding "**Approval of Financial Support to GENCOs**" and approved a Supplementary Grant of Rs.500.00 million for payment of Salaries, Pensions, overheads etc., in respect of GENCO-IV, Lakhra. However, Power Division shall consult Finance Division for meeting requisite codal formalities in this regard.

II. The ECC also constituted a Committee under the Chairmanship of Secretary, Power Division and comprising of Mr. Anwar Shaikh, Senior Joint Secretary, Finance Division and Representative of NEPRA with following terms of reference regarding those plants:

i. Justification for the closure and cost savings;
ii. Assessment of cost incurred on the closure;
iii. Loss of Revenue due to the closure;
iv. Broad based impact on the books of the government;
v. Viable options for disposal of assets pertaining to those plants.

III. The committee shall submit its report to the ECC for consideration within one month. The Power Division shall provide secretarial support to the committee.

Northern Power Generation Company Limited
Thermal Power Complex, Mahmood Kot Road, Muzaffargarh

Chief Executive Officer **Phone: 066-9200165**

No. CEO/MZG/204-05 Dated: - 18-10-2022

The Registrar,
National Electric Power Regulatory Authority,
Islamabad.

Subject: **NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-2031 (IGCEP-2022)**

Reference: NEPRA Notice issued on 27.09.2022 for comments.

Dear sir,

This is with reference to above referred notice for seeking comments in the matter of Indicative Generation Capacity Expansion Plan 2022-2031 (IGCEP-2022), as submitted by NTDC to NEPRA for review and approval.

In this regard, it is to submit that NTDC while preparing the draft IGCEP has assumed Units 5 & 6 of Thermal Power Station Muzaffargarh as non-operative, wherein other four units of Thermal Power Station Muzaffargarh have been considered to be retired till 2023 based on Cabinet Committee on Energy ("**CCoE**") decision of 10.09.2020, despite the fact that useful life of the units, as already determined by NEPRA in latest License modification issued on 02.05.2018, is up to 2033 ***(Annex-A)***. Moreover units of GTPS Faisalabad have been considered delicensed whereas LPM for extension in license term has been filed with NEPRA and decision is still pending.

A. **CCoE Decision of 10.09.2020:**

Cabinet Committee on Energy ("**CCoE**") on 10.09.2020, under case No. CCE-47/14/2020, decided closure of following plants of Northern Power Generation Company Limited:

1. Immediate closure of Units 5 & 6 of Thermal Power Station ("**TPS**") Muzaffargarh.
2. Closure of remaining units 1-4 of Thermal Power Station Muzaffargarh till September 2022.
3. Closure of units 5-9 of Gas Turbine Power Station ("**GTPS**") Faisalabad till Commissioning of Trimmu Power House.

Latest Status

a) In latest scenario, as informed by GHCL vide letter No. GHCL/CEO/591-94 dated 23.02.2022 ***(Annex-B)***, Power Division submitted a summary for financial support to GENCOs keeping in view the financial crisis of GENCOs. This summary was considered by the **Economic Coordination Committee of the Cabinet** in its meeting held on 23.09.2021 under case No. ECC-348/32/202.

b) ECC in this regard constituted a committee under the chairmanship of Secretary Ministry of Energy (Power Division) and comprising of Mr. Anwar Sheikh, Senior Joint Secretary Finance Division and representative of NEPRA ***(Annex-C)*** regarding GENCOs plants decided to be closed by CCoE. The TOR of the committee is as below:

i. Justification of the closure and cost savings;

ii. Assessment of cost incurred on the closure;
iii. Loss of revenue due to the closure;
iv. Broad based impact on the books of Government;
v. Viable option for disposal of assets pertaining to those plants.

c) Further to this and as informed by GHCL vide letter No. GHCL/CEO/CTO/1012-15 dated 03.03.2022 ***(Annex-D)***, GHCL has been directed to hire a consultancy service for a study to decide future of operational and non-operational plants of GENCOs. Draft Scope of study has also been shared by GHCL to hire consultancy services which are as below:

i. Assessment of useful life of these power plants.
ii. Assessment of need of these plants for the power system in Pakistan.
iii. Economic viability of these plants, based on location of each power plant, including but not limited to, net delivered cost to the consumer, grid stability, fuel & skilled human resource etc.
iv. Rehabilitation need of these power plants, if any, to make these plants competitive in current power market.
v. Assessment of fair determination of tariff by NEPRA for these GENCOs vis-à-vis principle of prudently incurred cost recovery.

d) Based on above assessment and analysis, the queries of the Economic Coordination Committee of the Cabinet will be addressed on justification of closure of plants, if any. The hiring of consultant is under process & not yet matured and the report is yet to be compiled by the consultant to decide future of NPGCL and other plants. It will be quite early to decide to retire these units unless directions of ECC are implemented.

B. <u>Comments of GM (System Operation) & GM (Power System Planning) NTDC:</u>

It is to further add that GM (System Operation) NPCC and GM (Power System Planning) NTDC have also endorsed operation of plants of TPS Muzaffargarh and GTPS Faisalabad vide their letters as mentioned below. Moreover GM (Power System Planning) has also suggested to conduct independent study to decide future of the plants being a very sensitive issue:

i. GM (SO) NTDC letter No. 158-168/GM(SO)/NPCC/DD(PC-II) dated 18.08.2020, addressed to Special Assistant to Prime Minister, recommended operation of all units of TPS Muzaffargarh till 2033 and that of GTPS Faisalabad till 2028 ***(Annex-E)***.

ii. GM (SO) NTDC letter No. 9737-45/GM(SO)/NPCC/DD(PC-II) dated 30.07.2020 ***(Annex-F)***, in response to NEPRA's query dated 06.07.2020 regarding units 4,5,6 of TPS Muzaffargarh and units 5-9 of GTPS Faisalabad, recommended operation of units 4,5&6 of TPS Muzaffargarh till 2033 and that of GTPS Faisalabad till 2028.

iii. GM (SO) NTDC letter No. 6438-40/GM(SO)/NPCC dated 04.05.2021, addressed to GM (Power System Planning) NTDC, wherein it was proposed to retain units 1,2,3,4 of TPS Muzaffargarh as units are required in high peak demand period to meet system load demand as well as to support overloading of 500/220 kV transformer at Muzaffargarh and New Multan Grid Station by ensuring system parameters in desired limits. These units can be retired once sufficient generation capacity is available and mentioned system/transformer constraints are removed.

iv. GM (Power System Planning) NTDC Letter No. GMPSP/1755-58 dated 05.05.2021 ***(Annex-G)***, endorsed the comments of GM (SO) NPCC as mentioned above at point No.

(iii). Furthermore, GM (Power System Planning) NTDC has proposed for conducting some independent study, if required.

C. Plant Utilization in recent years:

The utilization of the plants in recent years is as below, which also shows that plants are being used by System Operator to ensure system stability & to meet electricity demand of the Country.

Name of plant	Year	Utilization of plants (%)	
		Time based utilization (%age of time, unit remained in operation)	Generation based utilization
Unit No. 3 of TPS Muzaffargarh (Most efficient)	2020-21	14.0 %	10.21 %
	2021-22	12.5 %	9.13 %
GTPS Faisalabad	2021-22	14.7%	8.51 %

D. Importance of TPS Muzaffargarh:

The importance of TPS Muzaffargarh can be envisioned in following broad sectors:

1. Strategic Location of the Power Complex for mid country infeed & to address the power swing effect on power system as well
2. Importance endorsed by System Operator NPCC and System Planning NTDC
3. Proof of important contingency reserve events from recent past
4. Only base load Power Complex in the vicinity after retirement of neighbouring IPPs in near future.
5. Versatility of fuel -- Aid to National Security
6. Avoid Mono fuel dependency
7. Importance of base load plants for entire energy sector
8. Utilize locally produced RFO

In the light of above narrated facts, it will be too early to decide closure of the plants unless recommendations of the high-power committee constituted by Economic Coordination Committee of the Cabinet are finalized. The third-party study is also proposed by GM (Power System Planning). It is to further add that the premature decommissioning / retirement of NPGCL Power Complex, on one hand will have impact on unavailability of robust units for utilization by National Grid and on the other hand huge financial investments made by GoP in recent past for construction of plants of TPS Muzaffargarh will be abandoned despite remaining useful life of approximately 13 years as per NEPRA's own determination.

It is therefore requested that NTDC must be directed to ensure presence of units of NPGCL in IGCEP 2022, till the expiry of useful life/recommended operational life by GM (SO) NPCC. The decision of high-power committee constituted by ECC will be implemented in true letter & spirit, once finalized.

Sincerely,

(Sabeeh Uz Zaman Faruqui)
Chief Executive Officer

C.C To:

1. MD/Chief Executive Officer (GHCL), 1st Floor, OPF Building, G-5/2, Islamabad.
2. M-File.

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/R/LAG-03/ 7734—39

May 2, 2018

Chief Executive Officer,
Northern Power Generation Company Limited,
Mehmood Kot Road,
TPS, Muzaffargarh.

Subject: **Modification in Generation Licence No: GL/03/2002**
Licence Application No. LAG-03
<u>Northern Power Generation Company Limited, (NPGCL)</u>

Reference: NPGCL's Licensee Proposed Modification (LPM) vide its letter dated September 29, 2016 (received on September 30, 2016)

It is intimated that the Authority has approved the Modification in Generation Licence No. GL/03/2002 in respect of Northern Power Generation Company Limited (NPGCL), pursuant to Regulation 10(11)(a) of the NEPRA Licensing (Application and Modification Procedure) Regulations 1999.

2. Enclosed please find herewith determination of the Authority in the matter of Licensee Proposed Modification in the Generation Licence of NPGCL along with Modification-III in the Generation Licence No. GL/03/2002, as approved by the Authority.

<u>Enclosure:</u> As above

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
* NEPRA *

2/5/18

(Iftikhar Ali Khan)

Copy to:

1. Secretary, Power Division, Ministry of Energy, A-Block, Pak Secretariat, Islamabad.
2. Managing Director, NTDC, 414-WAPDA House, Lahore.
3. Chief Executive Officer, CPPA-G, ENERCON Building, Sector G-5/2, Islamabad.
4. Chief Executive Officer, Faisalabad Electric Supply Company (FESCO), Abdullahpur, Canal Bank Road, Faisalabad.
5. Director General, Environment Protection Department, Government of Punjab, National Hockey Stadium, Ferozepur Road, Lahore

Details of Generation Facility at Plant-I/TPS, Muzaffargarh

(A). Plant Configuration

(i).	Plant Size/ Installed Capacity (Gross ISO)	1350 MW					
(ii).	Type of Technology	Conventional Steam Turbine Thermal Power Plant					
(iii).	Number of Units/Size (MW)	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		210 MW Steam Turbine	210 MW Steam Turbine	210 MW Steam Turbine	320 MW Steam Turbine	200 MW Steam Turbine	200 MW Steam Turbine
(iv).	Unit Make & Model	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		T.P.E USSR	T.P.E USSR	T.P.E USSR	CMEC China	CMEC China	CMEC China
(v).	Commercial Operation date (of each Unit)	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		Sep. 1993	Mar. 1994	Feb. 1995	Dec. 1997	Dec. 1995	Dec. 1995
(vi).	Expected Useful Life of the Generation Facility/Plant-I from Commercial Operation Date (of each Unit)	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		39 Years	38 Years	37 Years	35 Years	37 Years	37 Years
(vii).	Expected Useful Life of the Generation Facility/Plant-I (Each Unit) at the time of Grant of Original Generation Licence	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		30 Years	30 Years	30 Years	30 Years	30 Years	30 Years

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

(viii).	Expected Useful Life of Expected Useful Life of the Generation Facility/Plant-I (Each Unit) at the time of Modification-I dated April 16, 2014	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		19 Years	19 Years	19 Years	19 Years	19 Years	19 Years
(ix).	Expected Useful Life of the Generation Facility/Plant-I (Each Unit) at the time of this Modification-II in Generation Licence (dated October 31, 2014)	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		19 Years	19 Years	19 Years	19 Years	19 Years	19 Years
(ix).	Expected Useful Life of the Generation Facility/Plant-I (Each Unit) at the time of this Modification-II in Generation Licence (dated April __, 2018)	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		15 Years	15 Years	15 Years	15 Years	15 Years	15 Years

(B). Fuel Details

(i).	Primary Fuel	Unit No.1	Unit No.2	Unit No.3	Unit No.4	Unit No.5	Unit No.6
		Furnace Oil					

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

GHC
GENCO HOLDING CO. LTD.

1st Floor, Overseas Pakistani Foundation, Shabra-e-Jumhuriyat, G-5/2, Islamabad.

Phone . (051)-9217601
Fax · (051)-9217602

No. GHCL/CEO/591-94 **February 23, 2022**

Chief Executive Officers:

1. Jamshoro Power Company Ltd. (GENCO-I)
2. Central Power Generation Company Ltd. (GENCO-II)
3. Northern Power Generation Company Ltd. (GENCO-III)
4. Lakhra Power Generation Company Ltd. (GENCO-IV)

Subject: **APPROVAL OF FINANCIAL SUPPORT TO GENCOS**

1. Ministry of Energy (Power Division) letter No.GPI-G(Misc)/2020 dated 29.09.2020.
2. Ministry of Energy (Power Division) letter No.GPI-G(Misc)/2021 dated 30.09.2021.
3. Ministry of Energy (Power Division) letter No.GPI-01(04)/2022 dated 15.02.2022.

The Ministry of Energy (Power Division) vide letter dated 29.09.2020 conveyed the decision of Cabinet Committee on Energy (CCoE) dated 10.10.2020 regarding closure of GENCOs' power plants in phases **(Annex-I)**.

In view of the financial difficulties currently being faced by GENCOs, as well as in the forthcoming years, owing to reduction in capacity charge, closure of power plants and shifting of tariff base on Take & Pay; the Power Division submitted a summary for financial support to GENCOs. The said summary was considered by the Economic Coordination Committee of the Cabinet in its meeting held on 23.09.2021 under Case No.ECC-348/32/2021 dated 23.09.2021. The approval of ECC was conveyed by Power Division vide letter dated 30.09.2021 **(Annex-II)**.

In the said decision the ECC approved supplementary grant of Rs.500 million for payment of salaries, pensions, overheads etc. in respect of Lakhra Power Generation Company Limited (GENCO-IV). The ECC also constituted a Committee under the Chairmanship of Secretary Power Division and comprising of Mr. Anwar Sheikh, Senior Joint Secretary, Finance Division and Representative of NEPRA with the following terms of reference (TORs) regarding GENCOs plants decided for closure by CCoE:

i. *Justification for the closure and cost savings;*
ii. *Assessment of cost incurred on the closure;*
iii. *Loss of Revenue due to the closure;*
iv. Broad based impact on the books of the government;
v. Viable options for disposal of assets pertaining to those plants.

GHCL/CEO/591-94 dated 23.02.2022

The Power Division vide letter dated 15.02.2022 has desired to submit working papers to proceed with the above TORs assigned by ECC (**Annex-III**).

In view of above, it is advised to please provide your valuable input covering, besides others, point-wise justification for each of the five TORs mentioned above.

Comprehensive reply of each GENCO, supported by documentary evidences, must reach this office within one week time.

MUHAMMAD IMRAN 23/02/22
Managing Director & CEO

417
25/02/22

(ANNEX-II)

SECRET

No.GPI-G(Misc)/2021
Government of Pakistan
Ministry of Energy
<><><>

Islamabad, the 30th September, 2021

The Chief Executive Officer,
GHCL,
Islamabad.

SUBJECT: **APPROVAL OF FINANCIAL SUPPORT TO GENCOs.**

Please find enclose of ECC decision bearing No. ECC-348/32/2021, dated 23.09.2021, on the subject above, and forwarded for information.

Encl: As above

(Muhammad Naeem)
Section Officer (GENCO's)

CC:

APS to Joint Secretary (T), Power Division, Islamabad.

GHCL	
Diary No: 3169	
Date: 01-10-21	
CEO	✓
CTO	✓
ADV (HR)	✓
CFO	✓
PMU	
Dir (Tech)	
Mngr (H.R&A)	
Sr. DA&O	

Case No.ECC-348/32/2021, Dated: 23rd September, 2021

APPROVAL OF FINANCIAL SUPPORT TO GENCOs

DECISION

The Economic Coordination Committee (ECC) of the Cabinet considered the summary dated 10th September, 2021 submitted by the Power Division regarding "**Approval of Financial Support to GENCOs**" and approved a Supplementary Grant of Rs.500.00 million for payment of Salaries, Pensions, overheads etc., in respect of GENCO-IV, Lakhra. However, Power Division shall consult Finance Division for meeting requisite codal formalities in this regard.

II. The ECC also constituted a Committee under the Chairmanship of Secretary, Power Division and comprising of Mr. Anwar Shaikh, Senior Joint Secretary, Finance Division and Representative of NEPRA with following terms of reference regarding those plants:

i. Justification for the closure and cost savings;
ii. Assessment of cost incurred on the closure;
iii. Loss of Revenue due to the closure;
iv. Broad based impact on the books of the government;
v. Viable options for disposal of assets pertaining to those plants.

III. The committee shall submit its report to the ECC for consideration within one month. The Power Division shall provide secretarial support to the committee

GHC

GENCO HOLDING CO. LTD.

First Floor, OPF Building
Sector G-5/2, Islamabad.

Phone: 051-9217601
Fax : 051-9217602

No. GHCL/CEO/CTO/ 1012-15

03.03.2022

Chief Executive Officers

1. Jamshoro Power Company Ltd. (GENCO-I)
2. Central Power Company Ltd. (GENCO-II)
3. Northern Power Company Ltd. (GENCO-III)
4. Lakhra Power Company Ltd. (GENCO-IV)

Subject: **CONSULTANCY SERVICES FOR CONDUCTING A STUDY TO DECIDE FUTURE OF OPERATIONAL AND NON-OPERATIONAL POWER PLANTS OF GENCOS**

Ref: GHCL letter ref: No.GHCL/CEO/591-94 dated February 23, 2022

This is in continuation to the GHCL letter under reference vide which the terms of reference (TORs) of the Committee already constituted by the ECC under the Chairmanship of Secretary Power Division were conveyed for valuable input of all the Chief Executives covering, besides others, point-wise justification for each of the five TORs mentioned in-there.

Further in the context, and while the input on referred letter is still awaited, GHCL has been directed to hire the consultancy services for a study to decide future of the operational and non-operational power plants of GENCOs. Draft TORs for the said consultancy services are attached herewith. Valuable comments on theses TORs as well as suggestions to strengthen the activity are requested within two days positively.

D/A: As above.

03/03/22

Engr. Dr. Niaz A. Memon
Chief Technical Officer

CONSULTANCY SERVICES FOR CONDUCTING A STUDY TO DECIDE FUTURE OF OPERATIONAL AND NON-OPERATIONAL POWER PLANTS OF GENCOS

PRELIMINARY TERMS OF REFERENCE

A. PLANTS UNDER SCOPE OF THE STUDY

The Cabinet Committee on Energy (CCoE) vide decision in Case No.CCE-47/14/2020 dated 10.09.2020 decided to close inefficient power plants of public sector generation companies i.e. GENCOs in two phases, which are tabulated as under. Table-1 states the power plants decided for immediate closure and Table-2 states the power plants currently retained for system requirement, however, decided to be closed till September 2022.

I. Power Plants to be Closed in First Phase:

Name of GENCO	Power Station / Block	Units	Capacity (MW)
JPCL (GENCO-I)	TPS Jamshoro	2 & 3	340
	GTPS Kotri	3 to 7	110
			450
CPGCL (GENCO-II)	Block 3 & 4	1 to 4	450
	TPS Quetta	6	22
			472
NPGCL (GENCO-III)	TPS MZG	5 & 6	355
	SPS FSD	1 & 2	97
	GTPS FSD	1 to 4	75
	NGPS MTN		192
	GTPS Shahdara		85
			804
LPGCL (GENCO-IV)	Lakhra	1 & 2	70
			1796

Table-1

II. Power Plants to be Closed in Second Phase:

Name of GENCO	Power Station / Block	Unit	Capacity (MW)
JPCL (GENCO-I)	TPS Jamshoro	1 & 4	400
CPGCL (GENCO-II)	GE Block, Guddu	5 to 10	600
	Siemens Block, Guddu	11 to 13	415
			1015
NPGCL (GENCO-III)	TPS Muzaffargarh	1 to 4	920
	GTPS Faisalabad	5 to 9	140
			1060
			2475

Table-2

B. SCOPE OF THE STUDY

1. Assessment of useful life of these power plants.
2. Assessment of need of these plants for the power system in Pakistan.
3. Economic viability of these plants, based on location of each power plant, including but not limited to, net delivered cost to the consumer, grid stability, fuel & skilled human resource etc.
4. Rehabilitation need of these power plants, if any, to make these plants competitive in current power market.
5. Assessment of fair determination of tariff by NEPRA for these GENCOs viz~a~viz principle of prudently incurred cost recovery.

Based on above assessment and analysis, address the following queries of the Economic Coordination Committee of the Cabinet:

i. Justification for the closure and cost savings.
ii. Assessment of cost incurred on the closure.
iii. Loss of revenue due to the closure.
iv. Broad based impact on the books of the government.
v. Viable options for disposal of assets pertaining to these plants.

NATIONAL TRANSMISSION & DESPATCH COMPANY Ltd

Phone 051 8311557
Exchange 051 9258177 78
Fax No 051 9257146

Office of the
General Manager (SO)
National Power Control Centre
H 8/1, Islamabad

No 152—62—/GM (SO)/NPCC/DD (PC II)

Dated 18—08—2020

Mr Shahzad Qasim,
Special Assistant to Prime Minister On Energy,
MoE (Power Division) Pak Secretariat,
Islamabad

Subject **Performance of Public Sector GENCOs**

A meeting was held on Sunday August 16, 2020 at CPPA-G office, vide MoE (Power Division) Letter No. PI-05(06)/2012 dated August 13, 2020, to review implementation of the decisions of CCoE and Tasks & Targets. The meeting was chaired by the Special Assistant to Prime Minister on Power Sector. During the meeting, the chair advised NTDC/NPCC and GENCOs to sit together and to assess the need to continue operating less efficient plants due to technical limitations of the system stability.

In light of the above directives, a meeting between GHCL/GENCOs and National Power Control Centre (NPCC) was held at the office of NPCC Islamabad on 17.08.2020 @ 1030 Hrs

Following officers participated in the meeting:

1.	Mr. Muhammad Ayub	General Manager (Ops), NPCC
2.	Engr. Dr. Niaz A. Memon	Chief Technical Officer, GHCL
3.	Syed Tanveer A. Jafri	Chief Executive Officer, GENCO-I
4.	Mr. Sabeeh-u-Zaman Faruqui	Chief Executive Officer, GENCO-III
5.	Mr. Rustam Ali Ghouri	Chief Engineer Technical Director, GENCO-I
6.	Mr. Abdul Kareem Memon	Director MIS, GENCO-II

Following discussions was made during the meeting:

Units	NPCC Comments	GENCO's comments	IGCEP retiring Year
GENCO-I TPS Jamshoro Unit NO: 01	Unit No: 01 is on top of merit order among TPS Jamshoro Generating Units 1-4. The Units of TPS Jamshoro are required during hot summer season, (on & off) when wind generation is low & in canal closer period. Therefore, the Unit No: 01 may be retired after Commissioning of 2*660MW coal fired Units of the same	• 300 MW of power is required at the location for optimum operation of the Jamshoro 500 kV Grid. • In absence of GTPS Kotri, (due to de-licensing) the operator was forced to operate Jamshoro steam units intermittently during last month (started six times during June-July 2020) to provide approximately	2030

	Station	100~150 MW for system stability. • It is much feasible and cost effective to operate 120 MW GTPS Kotri on combined cycle mode on gas fuel @ less than Rs. 10 / kWh. • It is worth to mention that the GTPS Kotri can assist the National Network for; i. GTPS Kotri is at 132kV Grid which is part of wind corridor circuit ii. Black Start to restore the National Network as & when required iii. Synchronous Condenser Operation to manage reactive power iv. GTPS Kotri will be much more viable on implementation of its repowering as proposed to NEPRA While the Units #2 &3 of GTPS Jamshoro should remain in operation till expiry of License i.e. 2028. However, it is more economical to run these units on indigenous gas. Can also operate as Contingency Reserve to keep the flexibility of fuel i.e. Coal/Gas/RFO	
<u>GENCO-II</u> TPS GUDDU Units No: 06	STG-06 of TPS Guddu is the combined cycle Unit of GT-09 & GT-10, whereas STG-05 is the combined cycle Unit of GT-07 & GT-08. These 6 Units comprise Block-02 of Guddu Power Plant operated on Indigenous and dedicated Natural Gas being supplied by OGDCL through a valid Gas agreement. As per merit order block-II is economical than many other power Plants running on RFO/LSFO & RLNG and also cheaper than some IPPs hydel Units. Therefore retirement of Unit No: 06 may consider on its due date.	• The block is a combined cycle plant based on GE Frame 9E gas turbine units which is a dependable & reliable machine and globally accepted for long life • It is unanimous consensus that the block is economical as commented by NPCC. • GENCO-II is in process of making the block more efficient which would enhance its position in the EMO. • TPS GUDDU is fueled by Kandh Kot (KK) gas field which is dedicated for this power station till its depletion for over next 15 years approximately. Therefore, the gas turbines license should match the	2023

		depletion schedule of KK Gas Field.	
GENCO-II TPS GUDDU Units No: 11,12 & 13	Unit No: 11, 12 & 13 comprises Block-I of TPS Guddu having combined Capacity of 404MW in which STG Unit No: 13 is in damaged condition since 2013, therefore the net capacity of Block- I at present is 230MW in open cycle bearing high cost than combine cycle tariff, but still lower than many RFO/LSFO& RLNG power plants already in operation. Unit No: 11, 12 were refurbished in 2018 and their capacities were restored near to the installed capacities (230MW). Therefore, instead of decommissioning of Units No11,12 & 13, CEO Guddu may be advised to rehabilitate STG-13 as early as possible as Block-I in combined cycle mode is more efficient than Block-II of same station just below 747 Units and will have positive impact on energy Mix cost.	GM NPCC is agreed to the point of view of GENCO-II and fully supported the retention of the block-II (Unit No.5 to 10) in the system due to imperative importance for the power system stability and for cheaper energy Mix cost. • It is unanimous consensus that the block-I (11,12&13) is economical in open as well as in combined cycle mode of operation as commented by NPCC. • Furthermore the rehabilitation of STG unit No 13 is already under process and the unit will be back on bar to make the block more economical and viable in EMO. GM NPCC is agreed to the point of view of GENCO-II and fully supported the retention of the block-I (Unit No 11,12 &13) in the system due to imperative importance for the power system stability and for cheaper energy Mix cost. • The up-gradation of TPS Quetta is being pursued in compliance to the recommendation of special committee on CPEC as conveyed by Ministry of Energy vide No.2 (1)/2020-IC-CPEC dated 11.08.2020 for its implementation.	
GENCO-III TPS MUZAFFARGARH Units No: 04,05, & 06	The Units of TPS Muzaffargarh are costly in the merit order on RFO but presently serving as a contingency reserve on southern Punjab in combination with Kapco, Lalpir & Pakgen during high demand months of May, June, July & Aug. However provision of RLNG to TPS Muzaffargarh would drastically lower the generation cost by approximately 50%.	• It is unanimous consensus that the plants are required due to strategic location and potential for future hybrid technology base enhancement as endorsed by NPCC.	2033

	Therefore, in order to utilize huge investment of GoP and keeping in view contingency status and its strategic location, the operation of TPS Muzaffargarh Units should be shifted from RFO to RLNG, so that it may be utilized efficiently & economically.		
GENCO-III GTPS FAISALABAD Units No: 05,06,07,08 & 09	GTPS Faisalabad is one of the two Power plants in Faisalabad city load center and its operation is very much useful to avoid the Overloading of Gatti Autos (4*450MVA) and it is helpful to reduce the system constraints. The operation of GTPS Faisalabad on Gas /RLNG would be beneficial and help NTDC to maintain the system stability, reliability and security within Grid code permissible limits in the area and also to avoid Load Management in Faisalabad.	• It is unanimous consensus that the plant is required due to its strategic location for load management at Faisalabad as endorsed by NPCC. • Importance of operation of plant as condenser to maintain System Voltage.	2028
General Comments of Genco's: It is further suggested that an independent committee may be constituted to assess the need to further operate/utilize less efficient and de-licensed plants based on strategic & technical viability for the system stability.			

Submitted for your kind perusal please.

NPCC

Mr. Muhammad Ayub

GENCOs

Mr. Abdul Kareem Memon

Engr. Rustam Ali Ghouri

Engr. Dr. Niaz A. Memon

Mr. Sabeeh-u-Zaman Faruqui

Syed Tanveer A. Jafri

C.C:

1. Secretary Energy, MoE (Power Division) Islamabad for information please
2. Managing Director NTDC, 414-Wapda house Lahore.
3. Deputy Managing Director (P&E), Wapda house Lahore.
4. General Manager (Technical), Wapda house Lahore.
5. Chief Executive Officer CPPA-G, Islamabad.
6. Chief Executive Officer GENCO Holding Company Ltd, Islamabad.
7. G.M (Power System Planning) PIA building, Lahore.
8. Chief Executive Officer GENCO-I, Jamshoro
9. Chief Executive Officer GENCO-II, Guddu.
10. Chief Executive Officer GENCO-III, Muzaffargarh.

NTDCL
Diary No: 2557
Date: 04/08/20
CEO
CTO
ADV (HR)
CFO
PMU
Dir (Tech) ✓
Mngr (HR&A)
Sr. DLAO

Pl dis—

NATIONAL TRANSMISSION & DESPATCH COMPANY Ltd

Phone: 051 8311557
Exchange: 051 9258177-78
Fax No: 051 9257146

Office of the
General Manager (SO)
National Power Control Centre
H-8/1, Islamabad

No. 9737-45 /GM (SO)/NPCC/DD (PC-II)

Dated: 30-07-2020

Managing Director, NTDC
414, Wapda Hous,
Lahore.

Subject: **Performance of Public Sector GENCOs**

Reference: NEPRA Email received on dated; 06.07.2020 (copy attached)

It is apprised that NEPRA vide above referred email has sought comments on technical and strategi importance of generating units/Machines of Public sector GENCOS (GENCO- I, II &II). The same is given as under:

Units	NPCC Comments	IGCEP retiring Year
GENCO-I		
TPS Jamshoro Unit NO: 01	Unit No: 01 is on top of merit order among TPS Jamshoro Generating Units 1-4. The Units of TPS Jamshoro are required during hot summer season, (on & off) when wind generation is low & in canal closer period. Therefore, the Unit No: 01 may be retired after Commissioning of 2*660MW coal fired Units of the same station.	2030
GENCO-II		
TPS GUDDU Units No: 06	STG-06 of TPS Guddu is the combined cycle Unit of GT-09 & GT-10, whereas STG-05 is the combined cycle Unit of GT-07 & GT-08. These 6 Units comprise Block-02 of Guddu Power Plant operated on Indigenous and dedicated Natural Gas being supplied by OGDCL through a valid Gas agreement. As per merit order block-II is economical than many other power Plants running on RFO/LSFO & RLNG and also cheaper than some IPPs hydel Units. Therefore retirement of Unit No: 06 may considered on its due date.	2023

JPCL 2.0 (c)

GENCO-II TPS GUDDU Units No: 11,12 & 13	Unit No: 11, 12 & 13 comprises Block-I of TPS Guddu having combined Capacity of 404MW in which STG Unit No: 13 is in damaged condition since 2013, therefore the net capacity of Block- I at present is 230MW in open cycle bearing high cost than combine cycle tariff, but still lower than many RFO/LSFO& RLNG power plants already in operation. Unit No: 11, 12 were refurbished in 2018 and their capacities were restored near to the installed capacities (230MW). Therefore, instead of decommissioning of Units No11,12 & 13, CEO Guddu may be advised to rehabilitate STG-13 as early as possible as Block-I in combined cycle mode is more efficient than Block-II of same station just below 747 Units and will have positive impact on energy Mix cost.	2023
GENCO-III TPS MUZAFFARGARH Units No: 04,05, & 06	The Units of TPS Muzaffargarh are costly in the merit order on RFO but presently serving as a contingency reserve on southern Punjab in combination with Kapco, Lalpir & Pakgen during high demand months of May, June, July & Aug. However provision of RLNG to TPS Muzaffargarh would drastically lower the generation cost by approximately 50%. Therefore, in order to utilize huge investment of GoP and keeping in view contingency status and its strategic location, the operation of TPS Muzaffargarh Units should be shifted from RFO to RLNG, so that it may be utilized efficiently & economically.	2033
GENCO-III GTPS FAISALABAD Units No: 05,06,07,08 & 09	GTPS Faisalabad is one of the two Power plants in Faisalabad city load center and its operation is very much useful to avoid the Overloading of Gatti Autos (4*450MVA) and it is helpful to reduce the system constraints. The operation of GTPS Faisalabad on Gas /RLNG would be beneficial and help NTDC to maintain the system stability, reliability and security within Grid code permissible limits in the area and also to avoid Load Management in Faisalabad.	2028

Keeping in view the aforementioned submissions on the subject matter it is requested that input Power System Planning may be taken in this regard and sent to NEPRA, so that suitable decision may be taken, please.

(Engr. Muhammad Ayyub)
GM (System Operation)
NPCC, NTDCL, Islamabad

C.C:

1. Deputy Managing Director (P&E), Wapda house Lahore.
2. General Manager (Technical), Wapda house Lahore
3. Chief Executive Officer CPPA-G, Islamabad
4. Chief Executive Officer GENCOs Holding company, Islamabad
5. G M (Power System Planning) PIA building, Lahore
6. Chief Executive Officer GENCO-I, Jamshoro
7. Chief Executive Officer GENCO-II, Guddu.
8. Chief Executive Officer GENCO-III, Muzaffargarh.

NATIONAL TRANSMISSION & DESPATCH COMPANY
National Power Control Centre, Sector H-8/1, Islamabad
Tel: 051-8311557, Fax: 051-9250851

General Manager
(System Operation)

No. 6494-98 GM (SO)/NPCC
Dated: 05-05-2021

Joint Secretary (Transmission),
NTDCL, Power Division MOE,
Islamabad

Attention: Mr. Hammad Raza Section Officer NTDC

Subject: Comments Regarding Retention or Retirement of GENCOs Power Plant Units

Reference:
Meeting with Secretary Power Division at Committee Room MOE Power Division on 4th May 2021

It is apprised that NPCC comments along with NTDC Power System Planning department comments in consolidated form regarding the subject matter is attached as Annexure-A for your information and further process please.

D/A: Annex:-A

05/05/2021

(Engr. Ghulam Abbas Memon)
General Manager (System Operation),
NPCC, NTDCL, Islamabad.

CC:
1. Managing Director NTDCL Lahore
2. Chief Executive Officer GENCO Holding Company
3. Deputy Managing Director (P&E), NTDCL Lahore.
4. General Manager Power System Planning NTDCL Lahore.

National Transmission & Despatch Company Ltd. (NTDC)

General Manager (Power System Planning)

No. GMPSP/ 1755-58

Dated: 05-05-2021

General Manager (System Operation)
NPCC, H-8/1, Islamabad.

Subject: Comments Regarding Retention or Retirement of GENCOs Power Plant Units

Ref: GM (SO) letter No. 6438-40 GM(SO)/NPCC dated 04-05-2021.

With reference to your letter No., the response of this office is given as under:

GENCO	Power Station/Block	Unit Nos	Fuel	Capacity MW	NPCC Comments	Power System Planning NTDCL Comments
I	TPS Jamshoro	3 & 4	RFO/Gas	400	Required during low wind in summer season to meet DISCOs & KE load demand. K-Electric increased its drawl from Jamshoro through 220 kV Jamshoro - KDA circuits after its rehabilitation in view of expected agreement of 1100 MW drawl between K-Electric, NTDCL & CPPAG yet to be signed.	Agree with NPCC comments for until the completion of 500 kV grid station at KKI when the power flow from Jamshoro to K-electric shall decrease.
II	Guddu GE Block	5 to 10	Gas	600	To be retained on merit order (Units are operated on Indigenous Gas). The units occupy higher rank in merit order.	Agree with NPCC comments
	Guddu Siemens Block	11 to 13	Gas	415	At present STG 13 is under fault (Since 24-03-2013) if it is restored then the block i.e., Units (11-13) in combined cycle is very cheap (Indigenous gas) as per Economic Merit Order. Even Units (11&12) being on open cycle mode are also cheaper than RLNG	Agree with NPCC comments

h

GENCO	Power Station/Block	Unit Nos	Fuel	Capacity MW	NPCC Comments	Power System Planning NTDCL Comments
					Plants and being Gas Turbine committed quickly as and when required.	
III	TPS Muzaffargarh	1 to 4	RFO/Gas	920	The units are required in high peak demand period to meet system load demand as well as to support overloading of 500/220 kV Transformers at Muzaffargarh and New Multan Grid Stations by ensuring system parameters in desired limits. These units can be retired once sufficient generation capacity is available and the above-mentioned system/transformer constraints are removed.	Generally agree with NPCC comments on availability of TPS Muzaffargarh plant. However, it needs to be checked by NPCC whether all four units are required OR fewer No. of units are required.
	GTPS Faisalabad	5 to 9	Gas	140	Must be retained till commissioning of Trimmu Powerhouse and 500 kV Faisalabad West Grid Station.	It needs to be re-considered in view of the fact that GTPS Faisalabad has not been used in recent past, as per our information.

In addition to above, this office is of the opinion that the subject matter is a very sensitive issue and is required to be considered not only for short term perspective as has been mentioned by NPCC but also for long term perspective. The assumptions of IGCEP 2021 have been finalized and IGCEP is going to be prepared shortly. It is suggested that the decision on the subject to be made after review of IGCEP 2021 and on the basis of detailed deliberations among relevant stakeholders like SO, CPPA-G, NTDC, PPIB, MOE(PD) etc. and some independent study may be conducted, if needed, in this regard.

(Engr. Anjum Aziz)
General Manager (Power System Planning)

Copy to:

1. Managing Director NTDC
2. Joint Secretary, Ministry of Energy (Power Division), Islamabad.
3. Dy. Managing Director (P&E), NTDC
- Master File

Government of Pakistan
Alternative Energy Development Board (AEDB)

AEDB

B/3/1/GWTech/17

October 20, 2022

Fw info & n.a

- DG (Lic)
copy to
- ADG (CT)
- SA (M&E)
- Cms. (Tech)
- Cms (CTBCM)
- m.f

Chairman
- m (M&E/CA)
- m (Lic/T)

REGISTRAR OFFICE
Diary No. 11221
Date: 26.10.2022

Mr. Shakil Ahmed
Additional Director
Registrar Office
National Electric Power Regulatory Authority
Islamabad.

Subject: **<u>Comments on Indicative Generation Capacity Expansion Plan 2022-2031 (IGCEP 2022)</u>**

This is with reference to NEPRA letter no. NEPRA/DG(Lic)/LAT-01/18675-33 dated September 27, 2022, on the subject matter.

2. This is to convey that AEDB has received several proposals from potential developers and provincial governments based on New Technologies under the ARE Policy 2019, which provides for the proactive procurement of electricity through New Technologies on the unsolicited mode. However, such proposals could not be processed by AEDB without incorporation of the quantum in the IGCEP, as Section 1.4.3 of the ARE Policy 2019 states that IGCEP outputs will form the basis of all on-grid capacity procurements.

3. In view of the provisions of the ARE Policy 2019 and considering the fact that various proposals on New Technologies are pending approval of AEDB, NTDCL was requested to allocate a quantum of approx. 1000 MW in the IGCEP 2022 through New Technologies. However, through the draft of the IGCEP 2022 submitted by NTDCL to NEPRA for approval, it has been noted that no quantum has been allocated for procurement of power through New Technologies.

4. Foregoing in view, NEPRA is requested to allocate a suitable quantum in the IGCEP 2022 for procurement of power through New Technologies. In this regard, it is proposed that a capacity of 1000 MW be initially considered for New Technologies in the IGCEP 2022.

(Sheeraz Anwar Khan)
Director (Wind/ST)

Copy to:

i. Chairman NEPRA, Islamabad.
ii. SPS to Secretary, Ministry of Energy (Power Division), Islamabad.

2nd Floor, OPF Building, Shahrah-e-Jumhuriat, Sector G-5/2, Islamabad.
Ph: 051-9202082/ Fax: 051-9222364

Government of Pakistan
Alternative Energy Development Board (AEDB)

AEDB

B/3/2/GC/19

31st October 2022

Members

1/11/2022

Chairman
National Electric Power Regulatory Authority
Islamabad.

Subject: **Allocation of Quantum in the draft Indicative Generation Capacity Expansion Plan 2022-2031 (IGCEP 2022) for Development of ARE New Technology Projects**

Registrar
DG (Licensing)

Dear Sir,

This is with reference to AEDB's comment given during NEPRA's hearing dated 19 October 2022 & AEDB's subsequent letter No. B/3/1/GWTech/17 dated 20 October 2022 on the subject matter.

2. It is apprised that ARE Policy 2019 and the National Electricity Policy 2021 requires a quantum in IGCEP to procure power from ARE projects either through competitive bidding (for matured technologies like wind solar & bagasse) or on Cost-plus tariff basis from unsolicited new technology based ARE projects.

3. AEDB is in receipt of several unsolicited project proposals on new technologies from the potential investors as well as from provincial governments (**Annex-I**). The received unsolicited project proposals are on Waste-to- Energy, Concentrated Solar Power (CSP) hybrid with PV, Power to X (P2X) electricity generation through green Hydrogen and solar PV with battery storage. It is important to highlight here that all the proposed ARE technologies will provide reliable and dependable power in the form of continuous supply, with no intermittency and no foreign cost on import of fuel for power generation.

4. The Section 1.4.3 of the ARE Policy 2019 states that IGCEP outputs will form the basis of all on-grid capacity procurements. Due to unavailability of quantum for new technologies in the IGCEP, AEDB is unable to process the received proposals. Moreover, AEDB does not have the cost and tariff data for the proposed projects at this moment as the firm project cost and expected tariff data would be available once these projects will conduct the detailed feasibility study after the issuance of Letter of Intent (LOI) by AEDB

1/11/22

REGISTRAR OFFICE
Diary No. 11572
Date: 2-11-2022

CHAIRMAN
Dy No. 7639
Date: 31-10-2022

2nd Floor, OPF Building, Shahrah-e-Jumhuriat, Sector G-5/2, Islamabad.
Ph: 051-9222365/ Fax: 051-9222364

For information
-DG (Lic)
copy to
-DD (T)
-SA (M&E)
-M.F

cc Chairman
-M (M&E/CF)
-M (Tech)

based on IGCEP quantum. Nevertheless, NEPRA will be approving the tariff of new technology projects as per GoP/NEPRA rules/regulations/policies.

5. AEDB vide letter dated 10 February 2022 had requested NTDC to allocate a suitable quantum in IGCEP 2022 for capacity addition through new ARE technologies and subsequently requested the same to NEPRA vide AEDB reference letter dated 20 October 2022.

6. In view of the aforesaid position, NEPRA is requested to consider allocation of 100MW quantum each year for development of unsolicited ARE projects on new technologies beyond 2024 up to 2031.

Best regards

(Shah Jahan Mirza)
Chief Executive Officer

Copy to:

i. Secretary (Power Division), Ministry of Energy (Power Division), Islamabad.
ii. Registrar, NEPRA, Islamabad.

Annex-I

LIST OF PROJECT PROPOSALS ON NEW TECHNOLOGIES

S. No.	Company Name	Project (TYPE)	Location	Capacity	Execution mode
1.	Chishtian Power (Pvt.) Ltd.	Concentrated Solar Power with Solar PV	Loralai, Balochistan	50 MW CSP 50 MW Solar PV	Request for issuance of hybrid LOI under ARE Policy 2019
2.	Grange Solar (Pvt.) Ltd. (GSPL file)	Concentrated Solar Power with Solar PV	Rahim Yar Khan, Punjab	50 MW CSP 50 MW Solar PV	Request for issuance of hybrid LOI under ARE Policy 2019
3.	Grace Solar Power Company (Pvt.) Ltd.	Solar PV with Lithium Battery Energy Storage	DG Khan	500 MW with 400 MW Battery Backup	Request for issuance of hybrid LOI under ARE Policy 2019
4.	Ziarat Energy (Pvt.) Ltd.	Concentrated Solar Power with Solar PV	Loralai, Balochistan	75 MW CSP and 75 MW Solar PV	Request for issuance of hybrid LOI under ARE Policy 2019
5.	P2X Energy	Hybrid of Solar, Wind and Hydrogen Project	Karachi & Gwadar	220 MW Solar 399 MW Wind 100 MW Hydrogen	Request for issuance of hybrid LOI under ARE Policy 2019
6.	Sowitech Operations GmbH	Hybrid of Solar, Wind and Battery Storage Project	Lasbela, Balochistan	51.2MW Solar 197.4MW Wind 31MW Battery Storage	Request for issuance of hybrid LOI under ARE Policy 2019
7.	Khan Renewable Energy (Pvt.) Ltd.	Waste to Energy	Rawalpindi / Islamabad	40 MW Waste to Energy Project	Request for issuance of LOI for new technology

Government of Pakistan
Alternative Energy Development Board (AEDB)

B/3/1/GWTech/17

October 20, 2022

Mr. Shakil Ahmed
Additional Director
Registrar Office
National Electric Power Regulatory Authority
Islamabad.

Subject: **Comments on Indicative Generation Capacity Expansion Plan 2022-2031 (IGCEP 2022)**

This is with reference to NEPRA letter no. NEPRA/DG(Lic)/LAT-01/18675-33 dated September 27, 2022, on the subject matter.

2. This is to convey that AEDB has received several proposals from potential developers and provincial governments based on New Technologies under the ARE Policy 2019, which provides for the proactive procurement of electricity through New Technologies on the unsolicited mode. However, such proposals could not be processed by AEDB without incorporation of the quantum in the IGCEP, as Section 1.4.3 of the ARE Policy 2019 states that IGCEP outputs will form the basis of all on-grid capacity procurements.

3. In view of the provisions of the ARE Policy 2019 and considering the fact that various proposals on New Technologies are pending approval of AEDB, NTDCL was requested to allocate a quantum of approx. 1000 MW in the IGCEP 2022 through New Technologies. However, through the draft of the IGCEP 2022 submitted by NTDCL to NEPRA for approval, it has been noted that no quantum has been allocated for procurement of power through New Technologies.

4. Foregoing in view, NEPRA is requested to allocate a suitable quantum in the IGCEP 2022 for procurement of power through New Technologies. In this regard, it is proposed that a capacity of 1000 MW be initially considered for New Technologies in the IGCEP 2022.

(Sheeraz Anwar Khan)
Director (Wind/ST)

Copy to:
i. Chairman NEPRA, Islamabad.
ii. SPS to Secretary, Ministry of Energy (Power Division), Islamabad.

2nd Floor, OPF Building, Shahrah-e-Jumhuriat, Sector G-5/2, Islamabad.
Ph: 051-9202082/ Fax: 051-9222364

Government of Pakistan
Alternative Energy Development Board (AEDB)

B/3/1/GWTech/17 February , 2022

General Manager (Power System Planning)
National Transmission and Despatch Company Limited (NTDCL)
4th Floor, PIA Tower, Egerton Road
Lahore.

Subject: **Data Requirements: Formulation of Indicative Generation Capacity Expansion Plan IGCEP 2022**

This is with reference to NTDCL letter no. GMPSP/CELF&GP/MLF&GP/404/486-512 dated January 25, 2022, on the subject matter.

2. As requested vide above referred letter, AEDB has submitted the project specific data of all the existing, under-construction & firm future ARE projects (falling under Category-I & II of the CCoE decisions) on the provided link (online). The print-outs of the data sheets (Wind – 38, Solar – 13 & Bagasse – 23) are also attached herewith for information & further necessary action at your end, please.

3. In addition to aforesaid projects, please be informed that all the future ARE projects falling under Category-III of the CCoE decisions and ARE Policy 2019 are required to be procured through competitive bidding process as per the decision of the Council of Common Interest (CCI) in its meeting held on August 06, 2020. The ARE Policy 2019 sets a target of achieving 20% capacity from ARE technologies by 2025 and 30% capacity by 2030 envisaging development of ARE projects in all parts of the country utilizing the available ARE resources. Accordingly, NTDCL is requested to also consider the ARE projects falling under Category-III and targets given under the ARE Policy 2019 while finalizing the IGCEP 2022, please.

4. It is also worth mentioning here that the ARE Policy 2019 also allows for proactive procurement of power through New Technologies on the unsolicited mode. In this regard, Section 1.4.3 of the ARE Policy 2019 states that IGCEP outputs will form the basis of all on-grid capacity procurements (except net-metering). In light of the above provisions of the ARE Policy 2019, AEDB has received several proposals based on New Technologies from potential developers and provincial governments. However, such proposals could not be processed by AEDB as the IGCEP 2021 provides quantum for capacity additions through wind & solar energy only. Accordingly, in view of the provisions of the ARE Policy

2nd Floor, OPF Building, Shahrah-e-Jumhuriat, Sector G-5/2, Islamabad.
Ph: 051-9222365/ Fax: 051-9222364

AS (1) Dy No. 525
Date 23-2-22

Dir (W)
Dir (SW)

CEO. AEDB

We may discuss

Government of Pakistan
Alternative Energy Development Board (AEDB)

2019 and considering the fact that various proposals on New Technologies are pending approval of AEDB, NTDCL is requested to allocate a suitable quantum in IGCEP 2022 for capacity addition through New Technologies. In this regard, it is proposed that 1000MW of new technology be initially considered for New Technologies in the IGCEP 2022.

5. AEDB remains available for any further assistance in the matter.

(Shah Jahan Mirza)
Chief Executive Officer

Copy to:

i. Secretary (Power Division), Ministry of Energy (Power Division), Islamabad.
ii. Managing Director, NTDCL, WAPDA House, Lahore.
iii. Chairman NEPRA, Islamabad.

2nd Floor, OPF Building, Shahrah-e-Jumhuriat, Sector G-5/2, Islamabad.
Ph: 051-9222365/ Fax: 051-9222364

For 4/1 2 (ed) / 2/11/22

– DG (Lic)

copy to

– ADG (T)

– SA (H&E)

– Cons. (Tech)

– m.f

Chairman

– m (H&E/CA)

– m (Lic T)

No: DAE/Gen/212/2021

GOVERNMENT OF SINDH

DIRECTORATE OF ALTERNATIVE ENERGY

ENERGY DEPARTMENT

Karachi dated: 28th October, 2022

SAY NO TO CORRUPTION

REGISTRAR OFFICE
Diary No. 11353
Date: 2.11.2021

To,

Mr. Shakeel Ahmed,
Additional Director,
Registrar Office,
NEPRA Tower, Attaturk Avenue (East), G-5/1,
Islamabad
PH: +92-51-9206500

Subject: **NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-2031 (IGCEP-2022)**

I am directed to refer to the letter No. NEPRA/DG/(Lic)/LAT-01/18675-33 dated 27th September, 2022 on the subject noted above and the views / comments are submitted as under:

(i) The Wind and Solar PV power projects of Sindh province has not been included in the committed projects list. In the last comments on IGCEP 2021-30, the Government of Sindh has already requested to include the five (5) numbers of Wind IPPs namely Moro (25 MW), Sinowel (50 MWs), Iran-Pak (50 MW), Norinco (100 MW) and Shafi Energy (50) with a cumulative capacity of 275 MW having the average leveled tariff of around US cents 3.4 per KWh and it is once again requested to include these least cost wind power projects in committed list of projects in the current IGCEP 2022-31.

(ii) Similarly, the Sindh Government also requested to include the least cost 1320 MWs coal based power plants by M/s Oracle power during preparation of IGCEP 2021-30. It's once again requested to include this project in the IGCEP 2022-31 to provide cheap electricity to people of Pakistan.

(iii) The IGCEP 2022-31 upto the year 2023-24, only 150 MWs of GoS utility scale Solar PV power projects has been considered as Category-II and PC-1 approved projects but according to the Variable Renewable Energy Locational Study conducted by the World Bank group, 700 MWs of Solar PV and 480 MWs of Wind can be evacuated in the HESCO and SEPCO grid stations and are technically feasible for grid integration in Sindh province for the short term scenario of 2023.

(iv) The fuel price indexation has based on June 2022 and the whole fiscal year is volatile so the NTDC must consider 2020-21 for the fuel price indexation.

(v) Local coal from Thar can be utilized for the coal power plants and can be operated as base load in the Power network.

(vi) The existing Coal Power plants on imported fuel need to be shifted to the indigenous coal.

(vii) The Government of Sindh has issued two (02) LOIs of 50 MW each for the development of Waste to Energy power plants in Karachi, Sindh which must also be included in the IGCEP 2022-31.

(viii) In reference to section 7.2 of the IGCEP 2022-31, the provincial grid company i.e. Sindh Transmission and Dispatch Company Ltd (STDC) may join hands to work with NTDC for upgradation and enhancement of Grids / Transmission network in Sindh province to evacuate power from the least cost Renewable Energy and Thar Coal based projects.

2. The above said comments are submitted for taking further necessary action please.

(ASIF JEHANZEB)
ASSISTANT DIRECTOR-II

Copy to:

1. DS(Staff)/PS to Minister for Energy, Government of Sindh, Karachi
2. PS to Secretary, Energy Department, Government of Sindh, Karachi
3. PA to Director Alternative Energy, Energy Department, Government of Sindh
4. Office file

No. ED/SO(P) 1(6)/9191-92

GOVERNMENT OF BALOCHISTAN
ENERGY DEPARTMENT
(Power Section)
Our Faith Corruption Free Pakistan

Dated Quetta the 30th December, 2022

To

The Chairman
National Electric Power Regulatory Authority
Islamic Republic of Pakistan, ***Islamabad***

Subject: NOTICE FOR SEEKING COMMENTS & PUBLIC HEARING IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-2031 (IGCEP-2022)

The undersigned is directed to refer to your letter No. NEPRA/DG(lic)/LAT-01/23343 dated 07-12-2022 regarding subject matter and to enclose herewith the comments of the Government of Balochistan for perusal/ consideration please.

30/12/2022
Section Officer
(Power)

Copy to:

1. The Additional Secretary (Staff) to Chief Secretary Balochistan
2. P.S to the Secretary to Government of Balochistan, Energy Department, Quetta
3. Master File.

CHAIRMAN
Dy No. 18
Date: 02-01-23

Registrar
DG (Licensing)

03-01-2023

4/1/23.

NEPRA
Licensing Department
Diary No. 64
Date: 05-01-23

GOVERNMENT OF BALOCHISTAN
ENERGY DEPARTMENT

COMMENTS OF THE GOVERNMENT OF BALOCHISTAN IN THE MATTER OF INDICATIVE GENERATION CAPACITY EXPANSION PLAN 2022-31 (IGCEP-2022)

S.No.	Clause of the Draft IGCEP	Comments of GoB
01	**Executive summary (Page-3):** *The base case shows a major contribution from renewable, i.e. 41% of hydropower and 20% of variable renewable energy mix by the year 2030*	Principally the contribution of variable renewable energy mix needs to be enhanced to 25% in the instant planning. After 2030 the generation capacity will get saturated, and it may not be possible to enhance the share of variable renewable energy.
	In order to determine the optimum quantum of Solar PV and wind sources that can be integrated in National Grid. The same will be considered in the next iteration of IGCEP.	Throw forward of the same for succeeding iteration every time may not be appropriate as the country is already overburdened w.r.t energy expenditure. We may calculate the time value of the technology adoption as well.
02	**Executive summary (Page-4):** *Indigenization of RE technologies through local manufacturing is also suggested to lower the basket price, for provision of relief to the end consumer as well as saving precious foreign exchange while maximizing the nature's endowment bestowed upon Pakistan.*	The vision of local manufacturing is appreciated. However, the mechanism for the engagement of manufacturing industry has not been suggested. It would be appropriate to suggest the Power Division to take the lead in collaboration with all the stakeholders.
03	**1.4 Objectives of the IGCEP**	Among four broader objectives of IGCEP, the identification and optimum utility of available resource may also be made part of the IGCEP objectives.
	The planning horizon of the ICCEP is from the year 2021-22 to 2030-31	Variation in the planning horizon of the IGCEP with every iteration creates unnecessary uncertainty. The instant iteration may please be treated an update in the existing planning horizon i.e. the previous iteration of IGCEP.
04	**1.8 Generation Capacity Expansion Software**	Generation optimization model based on the generation planning tool i.e. PLEXOS may please be updated by insertion of the resource consideration.
05	**2.1 Economics of Pakistan Power Sector** *GDP is positively related with the sales of electricity*	Since IGCEP is used as one of the main inputs to the TSEP, Balochistan may be given a prioritized status keeping in view

		the socio-economic situation of the province.
06	<u>2.2 Power Generation</u> *As of June-2022 the total installed capacity of NTDC system reached to 37,949 MW. Out of which 34% is RE share which comprises of hydro, solar PV, wind and bagasse-based technologies and 66% share is from thermal projects comprising of local gas, local coal, RFO, RLNG and nuclear based technologies.*	The chart shows 1% of Solar contribution and 5% of Wind based technologies with a cumulative generation capacity of 2300 MW. Whereas the Solar-wind hybrid potential of Balochistan is more than 8000 MW (World Bank VRE Locational Studies 2019). To get rid of expensive fossil fuels, it would be appropriate to un-tap the Solar-Wind potential of Balochistan.
07.	<u>3.3 The IGCEP Data Sources and Associated Data Types</u>	The data source does not include the data from Balochistan Power Development Board (BPDB) or Energy Department, Government of Balochistan. Acquisition of data from all the federating units and the relevant agencies may please be made mandatory as in the instant case potential of Balochistan has not been considered at all.
08	<u>3.6.4 Renewable Energy (RE) Generation</u> *Subsequent Cabinet Committee on Energy (CCoE) decision of April 4, 2019 and June 16, 2020, RE Projects, i.e. wind, solar PV, and bagasse (currently under litigation except Shahtaj) defined under Category-I and II, presently at different stages of development are envisaged to be added into the national grid during the next couple of years.*	All the candidate projects of Solar PV from Balochistan were placed in Category –III as per CCoE decision **(Annex-A)** and the instant draft does not undertake any plan for power uptake from the projects in Category-III. These are the cheapest projects for which the GoB had already issued LOIs which must have been included in the IGCEP on least cost/competition basis. It is, therefore, evident that the resource of Balochistan province has not been considered even for next 10 years. It is pertinent to mention here that the Balochistan has the best solar irradiation and one of the best wind corridors in the region **(resource map enclosed Annex-B).** By excluding the resources of the province in planning phase we may not be able to develop a sustainable and efficient energy mix for the country. Therefore, the instant clause may please be reconsidered by setting a clear direction towards candidate projects in Category –III.
09	<u>4. Long Term Energy and Power Demand Forecast</u> <u>4.2.1 Long Term Demand Forecasting Methodology</u>	Balochistan forms 43% of the land mass of the country and houses just 6% of the population. Due to long distances almost 60% of the area and 40% of the population has no access to electricity at all. It is not clear in the long term demand

		forecasting methodology whether the un-served area/population has been made part of the input variables or otherwise. If otherwise then the plan may lack in reflecting true forecast and may fail to serve the purpose of ensuring access to electricity for every one across the country. The un-served area/ population may also be made part of inputs as an effective variable in long term demand forecasting methodology.
10.	<u>4.4.3 Load Management</u> <u>AT&C (Aggregate Technical and Commercial) and Non-AT&C Load Management</u> AT&C load management is being carried out deliberately on the feeders where recovery is very low due to electricity theft and other governance issues. Non AT&C is being carried out due to system constraints, fuel shortage and voltage profile etc.	The socio –economic situation of Balochistan, electricity prices and lifeline consumers of electricity make the recoveries slow in the province. Whereas sever issues of governance with the relevant disco i.e. QESCO add up in the liabilities. Therefore, AT&C load management factors for the province may not be generalized. The marginalized province with meager network coverage may get more deprived if general assumptions are applied for load management. It is,, therefore, requested that Balochistan may please be treated separately with specific sets of assumptions in case of load management.
11	<u>4.6 Energy and Power Demand Forecast Numbers</u>	Comments at S.No. 9/n above w.r.t **<u>4. Long Term Energy and Power Demand Forecast</u>** **<u>4.2.1 Long Term Demand Forecasting Methodology</u>** are reiterated. Keeping in view the above it is feared that the Energy and Power Demand Forecast may not be accurately reflected.
12	<u>5.2 Assumptions of IGCEP</u> *31. **140 MW Habibullah Coastal (HCPC)** and 31 MW Altern Energy Limited (AEL) have not been considered in the existing installed **capacity owing to termination of Gas Supply Agreement (GSA)** and de-licensing by NEPRA, respectively.*	Excluding 140 MW Habibullah Coastal (HCPC) will reduce the energy security for provincial capital i.e. Quetta City. HCPC used to serve as an alternate source of energy in case of power failure due to any reason. It is pertinent to mention here that the provincial capital had no electricity for almost 15 days in the recent floods. In addition to that the HCPC also serves as a system stabilizer because it is the only Power Plant in the central Balochistan. As Guddo-II U(5-10) 620 MW Gas Powered power station is due for retirement

		in 2023, the restoration of gas supply to 140 MW HCPC healthy power plant is quite possible. The Company and GoB both are extensively pursuing the matter of the restoration of gas supply to power plant. We understand that selection of any generation project in IGCEP does not ensure any guarantee to execute that project which has to undergo approvals from relevant government authorities. It is, therefore, requested that the HCPC may please be made part of installed capacity subject to restoration of gas supply.
13	5.9.1 List of Committed Projects	The list contains 72 committed projects but from Balochistan no project could make place in the list. Though the Government of Balochistan has repeatedly requested to list at least three projects of Solar PV in the province i.e. 50 MW Enertech Quetta, 50 MW Enertech Bostan and 50 MW P&G Gwadar as committed. It is pertinent to mention here that the projects of Enertech are to be developed by the Enertech Holding Company (a state-owned company of Kuwait). These could have been taken as G2G projects. Whereas 50 MW Solar PV Project of P&G at Gwadar may be listed as committed one as a strategic project owing to the strategic importance of Gwadar. The project briefs are enclosed **(Annex-C)**. It is, therefore, requested that these projects of Balochistan may please be listed as committed projects in the instant iteration of IGCEP.

* In addition to above, the (10x50 MW) Letters of Intent (LoI) issued by Balochistan Power Development Board (BPDB) to M/S Engro Energy for establishment of Wind based Power Projects in Nokundi wind corridor have not been considered at any stage. As per VRE Locational Studies carried out by World Bank, Nokundi is one of the best wind corridors of the region with 20% higher wind speed at average if compared with Jhampir (Sindh). Establishment of 10 wind-based power projects will be tip of the iceberg in given length of the corridor inside Pakistani boundaries. Un-tapping the wind potential of Nokundi/ Chagai Wind Corridor shall change the cost of entire energy basket of the country by reducing the cost exponentially. Since, investors are ready to finance the project and NTDC has already

been approached for construction of transmission line, it would be appropriate to include the same in planning in the instant iteration of IGCEP.

It is reiterated that the since the current plan does not contain anything to tap the cheapest resource of Balochistan province for the next ten years and it is restricted towards committed projects only therefore the GoB does not support the proposed IGECEP.

30/12/2022

Section Officer
(Power)

ANNEX – A

Secret/
Most Immediate/

No.1(nd)RE Policy 2019
Government of Pakistan
Ministry of Pakistan
(Power Division)
***

Islamabad, June 16, 2020

SUBJECT: DECISION OF THE MEETING OF CABINET COMMITTEE ON ENERGY (CCOE).

I am directed to refer to the subject captioned above and to convey herewith the decision of the CCoE pertaining to your office, which is reproduced as under:

Case No.CCE-24/06/2020 dated 4th May, 2020.

AMENDMENT IN DECISIONS OF THE CABINET COMMITTEEON ENERGY HELD ON 17TH DECEMBER 2017 AND FEBRUARY 2018.

The Cabinet Committee on Energy (CCoE) considered the summary dated 22nd April 2020 submitted by the Power Division regarding Amendment in decisions of the cabinet committee on energy held on 17th December 2017 and February 2018 and approved the proposals contained in para 3 of the Summary.

II. With regard to finalization/ implementation of the Renewable Energy Policy, the CCOE directed Power Division to resolve the outstanding matters with the Government of Sindh and have the policy notified by the IPC Division at the earliest. In the event of a future to resolve the oust sanding matters, the Power Division shall move a summary to the Council of comment Interest (CCI), by 15th June 2020 Power Division shall submit its proposals for an interim arrangement to the CCOE, in the event that none of the forging actions can be accomplished by 15th June, 2020.

2. The para 3 of the Summary, as per decision (i), above of the CCoE is reproducing as under:-

"3. While approval of the decision, a category wise list of projects was also approved. Subsequent to the decision of Cabinet Committee on Energy (CCoE), several project companies approached Power Division and Alternative Energy Development Board (AEDB) for inclusion in Category II from Category III. The Alternative Energy Development Board constituted a Committee for review of applications received for change of category. The AEDB Board, in its 49th Board Meeting held on 15th January, 2020 endorsed the following recommendation of Board's committee for enlistment of projects in category-II and category-III, as under (Annex-I):-

The following projects have been recommended by the AEDB Board from Category-III to inclusion in Category-II.

Sr No	Name of Project	Capacity	LOI issued by	Recommendation
1	Zorlu Solar Pakistan Ltd	100 solar	GoPb	Project fulfils the eligibility criteria for Cat-II and is therefore recommended for inclusion in Cat-II, and deletion from Cat-III.
2	Zhenfa Pakistan	100 solar	GoPb	Project fulfils the eligibility criteria for Cat-

D.i.(P)

For info & N/A.

DIR (W)

	New Energy Company Pvt.Ltd			II and is therefore recommended for inclusion in Cat-II and deletion from Cat-III. Moreover, LOI issuing agency to be amended as GoPb.
3	Lahore Xingzhong Renewable Energy Company Ltd.	40 Solid waste	GoPb	Project fulfils the eligibility criteria for Cat-II and is therefore recommended for inclusion in Cat-II instead of Cat-III after verification by the Ministry of Energy (Power Division).
4	Siachen Energy Ltd.	100 Solar	GoS	Project fulfils the eligibility criteria for Cat-II and is therefore recommended for inclusion in Cat-II Instead of Cat-III

The following projects have been recommended by the AEDB Board to whom LOIs have been issued by GoB prior to the expiry of RE Policy 2006, i.e. 8th March, 2018 and therefore fulfill the criteria for inclusion in Category-III. The detail of these projects is as under:-

Sr No	Name of Project	MW	LOI issued by	Recommendation
1	IB Voght GmbH	50 Solar	GoB	LOIs for these projects have been issued by GoB prior to the expiry of RE Policy 2006, i.e. 8th march, 2018 and therefore fulfil the criteria for inclusion in Cat-III.
2	IB Voght GmbH	50 Solar	GoB	
3	IB Voght GmbH	50 Solar	GoB	
4	Engro Energy	50 Solar	GoB	
5	Engro Energy	50 Solar	GoB	
6	Engro Energy	50 Solar	GoB	
7	Engro Energy	50 Solar	GoB	
8	Engro Energy	50 Solar	GoB	
9	Engro Energy	50 Solar	GoB	
10	Engro Energy	50 Solar	GoB	

The following projects have been recommended by AEDB Board to be remained in Category-III, as they do not fulfill the eligibility criteria:-

Sr No	Name of Project	MW	*LOI Issued by*	***Recommendation***
1	Siddiqsons Pvt Ltd	50	*GoKPK*	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
2	Siddiqsons Pvt Ltd	50	*GoKPK*	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
3	FAS Energy Ltd	50	*GoKPK*	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*

4	Target Energy Pvt Ltd	50	GoKPK	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
5	Assal Solar Power	50	GoKPK	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
6	Burj Wind Energy Pvt.Ltd	14	AEDB	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
7	Iran Pak Wind Power Pvt Ltd	50	GoS	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
8	Norinco International	50	GoS	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
9	Moro Power company Pvt.Ltd	25	GoS	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*
10	Shaffi Energy Pvt.Ltd	50	GoS	*The project does not fulfil the eligibility criteria for Cat-II and is rightly placed in Cat-III.*

The following new projects have been recommended by AEDB Board for inclusion in Category-III:-

Sr No	Company Name	MW	LoI Issued by	Recommendation
1	Thatta Power Pvt.Ltd	50	GoS	The project does not fulfil the eligibility criteria for cat-II and is rightly placed in Cat-III
2	Sinowell Pvt.Ltd	50	GoS	The project does not fulfil the eligibility criteria for cat-II and is rightly placed in Cat-III

The following project has not been recommended by AEDB Board for inclusion in category-III

Sr No	Company Name	MW	LoI Issued by	Recommendation
1	Engro Energy	50x10	GoB	The projects do not fulfil the criteria for inclusion in Cat-III

3 The above decision is communicated for implementing and further necessary action in the matter under intimation to this division.

S. Mateen

(Syed Mateen Ahmed)
Section Officer (Tariff)

DISTRIBUTIONS:

1. Chief Executive Officer –CPPA'G, Islamabad.
2. Chief Executive Officer –AEDB, Islamabad.

C.C

i. PS to Minister for Energy, Power Division.
ii. PSO to Secretary, Power Division, Ministry of Energy.
iii. SPS to Additional Secretary-II, Power Division, Ministry of Energy.
iv. PS to Joint Secretary (PF), Power Division, Ministry of Energy.

F-No.Tariff /RE POLICY-2019
Government of Pakistan
Ministry of Energy
Power Division
****

Islamabad, the April 04, 2019

Managing Director,
NTDC Wapda House,
Lahore.

Chief Executive Officer,
AEDB, Islamabad.

Chief Executive Officer,
CPPA-G Islamabad.

Managing Director,
PPIB, Islamabad.

Chairman NEPRA,
Islamabad.

Subject: - <u>AMENDMENT IN DECISIONS OF THE CABINET COMMITTEE ON ENERGY HELD ON 17TH DECEMBER 2017 AND FEBRUARY 2013</u>

I am directed to refer to this Division letter No.Tariff /RE POLICY-2019 dated the 01st April, 2019 on the above subject and to state that the letter is hereby withdrawn ab initio.

2. The CCoE decision on case No. CCE-12/04/2019 (V) conveyed by above referred letter be read as under:-

I. *All future RE investments will have to be dealt with under RE Policy 2019 which will clearly enunciate a framework in consistent with current international market norms and greater consumer benefits;*

II. *Any resource risk that is linked with RE projects being considered as pipeline projects under the RE Policy 2006 which conform to NEPRA's decisions taken in various tariff determinations of such projects(resource risk for wind, solar and hydel), would be henceforth borne by the seller;*

III. *All processing of the above projects would be linked with the date of grid interconnectivity as provided and confirmed by NTDCL;*

IV. *All those projects which have been granted LOS by AEDB will be permitted to proceed towards the achievement of their requisite milestones as per RE Policy 2006. However, if more than one year has elapsed since determination of tariff by NEPRA, the said tariffs will be reviewed by NEPRA to bring them in line with the prevailing market conditions and rationalization of cost keeping in view consumer interest as well as subsequent determinations on the same technologies given by NEPRA. Such review shall include appropriate time extension to reach financial closing.*

V. *All projects that have been issued LOIs and have been granted determination of tariff by NEPRA and issued a generation license would be allowed to proceed ahead towards the achievement of their requisite milestones as per the RE Policy 2006. However, if the tariff determination has been done since more than one year or if the tariff validity period has elapsed, NEPRA would be requested for review of the same to make it consistent with the current market environment/conditions and consumer interest. Such review shall include appropriate time extension to reach financial closing;*

VI. *In all these projects, grid connectivity date will have to be approved by NTDC and the COD will be subject to the same.*

VII. In case of wind projects that fall in the above categories and are situated in the wind corridor of Jhimpir, Sindh, the NTDC and the Sindh Government will work on the proposal of the Sindh Government for construction of evacuation facilities from the said corridor by the Sindh Government and will be reflected in a firm agreement between the two.

VIII. Based on NTDC's confirmation of evacuation and the timeline decided for completion of the projects, the CPPA-G will consider granting of consent.

IX. Projects that have been issued LOI prior to the expiry of RE Policy, 2006 on March 08, 2018 but have not received a tariff from NEPRA, may be allowed to proceed ahead subject to becoming successful in the competitive bidding process to be undertaken by AEDB specifically designed for each technology under this category based on the quantum ascertained for each technology by Indicative Generation Capacity Expansion Plan (IGCEP) by NTDCL. Once IGCEP by NTDCL determines how much additional power it needs to induct in the system by June 2023 as approved by the regulator and NTDCL confirms its interconnection including the completion of pre-requisites for issuance of Power Acquisition Request, AEDB will conduct competitive bidding, one for each technology, for the capacity to be procured under each technology, with resource risk being borne by the Project. The determination of size of each block will be done by NTDCL within 60 days of the approval of IGCEP and accordingly the capacity of wind, solar and bagasse power to be inducted through competitive bidding shall be intimated to AEDB. Thereafter, AEDB will develop the bidding documents based on the parameters determined by NEPRA. For projects which are regarded successful in the bidding process, an LOS shall be issued subsequently allowing the projects to achieve Financial Closing as per the time period allowed in the LOS. All other LOIs which are not successful in the bidding process shall stand lapsed and bank guarantees provided against the LOI will be returned in full.

X. The sponsors willing to proceed with the development of their respective projects under this mechanism will be required to provide an undertaking to withdraw all lawsuits against Federal/Provincial Governments.

XI. Projects that are going back for review of tariff, will be asked to submit their applications on the basis of latest technology and technology related factors.

3. The list of projects (145) as approved by the Cabinet is enclosed for necessary action pl.

4. This issues with the approval of Secretary of Energy, Power Division.

(Syed Mateen Ahmed)
Section Officer (Tariff)

C.C:

1. PSO, to Minister for Energy, Power Division, Islamabad.
2. SPS, to Secretary, Power Division, Islamabad.
3. SPs, to Addl. Secretary, Power Division, Islamabad.
4. PS to Joint Secretary (PF), Power Division, Islamabad.

i. Projects at LOS Stage

There are 19 projects in this category totalling 531.02 MW, with 15 projects of a total of 489.5 MW of bagasse and 4 projects of a total of 41.52 MW of solar power projects. List of project under this category is given below:

Sr#	Name of Project	LOI Issued By	Type	Capacity (MW)	Date of Tariff Award	Tariff (US cents /kWh)	Generation License
1	Access Solar (Pvt.) Ltd.	AEDB	Solar	11.52	11-Oct-13	5.9374	22 Aug, 2013
2	Access Electric (Pvt.) Ltd.	AEDB	Solar	10	11-Oct-13	5.9374	26 Jun, 2014
3	Bukhsh Solar (Pvt.) Ltd.	AEDB	Solar	10	29-Feb-16	14.4096	26 Jun, 2014
4	Safe Solar Power Pvt. Ltd	AEDB	Solar	10	29-Feb-16	14.4096	12 Sep, 2014
5	Shahtaj Sugar Mills Ltd at, Mandi Bahauddin, Punjab	AEDB	Bagasse	32	Jan 02, 2017	10.6202	10 Nov, 2016
6	Hunza Power (Pvt.) Ltd, District Jhang, Punjab;	AEDB	Bagasse	49.8	Feb 22, 2017	10.6202	20 Mar, 2017
7	Ittefaq Power (Pvt.) Ltd, District Bahawalpur, Punjab	AEDB	Bagasse	31.2	May 25, 2017	10.6202	04 May, 2017
8	Kashmir Power Private Ltd, District Jhang, Punjab	AEDB	Bagasse	40	April 26, 2017	10.6202	30 May, 2017
9	Indus Energy Limited, District Rajanpur, Punjab	AEDB	Bagasse	31	April 26, 2017	10.6202	13 June, 2017
10	Bahawalpur Energy Ltd, District Jhang, Punjab	AEDB	Bagasse	31.2	April 26, 2017	10.6202	02 May, 2017
11	Alliance Sugar Mills Ltd, Ubauro, District Ghotki, Sindh	AEDB	Bagasse	30	Sep 11, 2017	10.6202	02 Oct, 2014
12	RYK Energy Limited, Rahim Yar Khan, Punjab	AEDB	Bagasse	25	Sep 11, 2017	10.6202	30 May, 2017
13	Two Star Industries Pvt Ltd,	AEDB	Bagasse	49.8	Sep 11, 2017	10.6202	25 Sep, 2017
14	TAY Powergen Company, Tando Allahyar, Sindh	AEDB	Bagasse	30	Sep 11, 2017	10.6202	20 Mar, 2015
15	Faran Power Ltd, District Tando Muhammad Khan, Sindh	AEDB	Bagasse	26.5	Sep 11, 2017	10.6202	13 June, 2017
16	Hamza Sugar Mill Limited (Unit-II), Rahim Yar Khan, Punjab	AEDB	Bagasse	30	Sep 11, 2017	10.6202	10 Oct, 2017
17	Sheikhoo Power Ltd, District Muzafargarh, Punjab	AEDB	Bagasse	30	Sep 11, 2017	10.6202	20 Sep, 2017

18	Mehran Energy Ltd, District Tando Allahyar, Sindh	AEDB	Bagasse	26.5	Sep 11, 2017	10.6202	26 Sep, 2017
19	Habib Sugar Mills Ltd, Shaheed Banazir Abad, Sindh	AEDB	Bagasse	26.5	Sep 11, 2017	10.6202	16 Oct, 2017
				531.02			

ii. Projects with LOI and Tariff Determination but no LOS

There are 22 projects in this category totalling 1199.3 MW, with 2 projects of a total of 90 MW of bagasse, 5 projects of a total of 350 MW of solar and 15 projects of a total of 759.3 MW of wind power projects. List of project under this category is given below:

Sr#	Name of Project	LOI Issued By	Type	Capacity (MW)	Date of Tariff Award	Tariff (US cents /kWh)	Generation License
1	Lakeside Energy Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7154	27 Nov 2017
2	Artistic Wind Power Pvt. Ltd.	GoS	Wind	50	19-Nov-18	4.7212	28 Mar 2017
3	Liberty Wind Power 1 Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7824	01 Feb 2017
4	Indus Wind Energy Ltd	GoS	Wind	50	19-Nov-18	4.7931	13 Jun 2017
5	Master Green Energy Ltd	GoS	Wind	50	20-Aug-18	4.1302	27 Nov 2017
6	ACT2 Wind Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7212	04 Apr 2017
7	Liberty Wind Power 2 Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7824	01 Aug 2017
8	Metro Wind Power Ltd.	GoS	Wind	60	19-Nov-18	4.6360	02 Aug 2017
9	Nasda Green Energy Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7190	03 Aug 2017
10	DIN Energy Ltd	GoS	Wind	50	19-Nov-18	4.7824	01 Feb 2017
11	Gul Ahmed Electric Ltd	GoS	Wind	50	19-Nov-18	4.7212	01 Aug 2017
12	Tricom Wind Power Pvt. Ltd	GoS	Wind	50	19-Nov-18	4.7824	08 Aug 2017
13	Western Energy Pvt. Ltd (CPEC PROJECT)	AEDB	Wind	50	20-Aug-18	4.3467	05 Jan 2017
14	Shaheen Renewable Energy Pvt. Ltd	AEDB	Wind	51	20-Aug-18	4.4154	07 Jan 2017
15	Trans Antlatic Energy Pvt. Ltd.	AEDB	Wind	48.3	20-Nov-18	4.3464	18 Apr 2017
16	Zorlu Solar Pakistan (Pvt.) Ltd.	GoPb	Solar	100	25-Jan-18	5.3086	18 Aug 2017
17	Helios Power (Pvt.) Ltd.	GoS	Solar	50	25-Jan-18	5.2622	16 Aug 2017
18	HNDS Energy (Pvt.) Ltd.	GoS	Solar	50	25-Jan-18	5.2622	16 Aug 2017

19	Meridian Energy (Pvt.) Ltd.	GoS	Solar	50	25-Jan-16	5.2622	16 Aug 2017
20	Zhenfa Pakistan New Energy Company (Pvt.) Ltd.	GoS	Solar	100	13-Aug-13	4.7746	10 Jul 2017
21	M/s Sadiqabad Power Pvt Ltd, Rahim Yar Khan, Punjab	AEDB	Bagasse	45	Sep 11, 2017	10.6202	17 Jul 2018
22	M/s Gotki Power Pvt Ltd, Ghotki, Sindh	AEDB	Bagasse	45	Sep 11, 2017	10.6202	27 Nov 2017
				1199.3			

iii. Projects At LOI Stage

There are 104 projects in this category totalling 6,547 MW, with 31 projects of a total of 2139 MW of wind, 65 projects of a total of 4143.5 MW of solar, 07 projects of a total of 224.5 MW of bagasse and 01 project of 40 MW of Waste-to-Energy (Municipal Solid Waste). List of projects under this category is given below:

Sr#	Name of Project	Capacity (MW)	Type	LOI Issued By	LOI Issuance Date
1	Burj Wind Energy Pvt. Limited	14	Wind	AEDB	10 Oct 2012
2	DHA City Karachi (DCK)	50	Wind	GOS	20 Oct 2014
3	Cacho Wind Energy (Pvt) Ltd *(CPEC Project)*	50	Wind	GOS	28 Nov 2014
4	Harvey Energy (Pvt) Ltd	50	Wind	GOS	28 Nov 2014
5	Finergy (Pvt) limited	50	Wind	GOS	13 Feb 2015
6	New Generation Power Pvt Ltd	100	Wind	GOS	17 Apr 2015
7	Norinco International Corporation Ltd	50	Wind	GOS	20 Apr 2015
8	Norinco International Corporation Ltd	50	Wind	GOS	20 Apr 2015
9	Power China Chengdu Engineering Corporation Ltd	150	Wind	GOS	3 Jul 2015
10	Harbin Electric International –II	250	Wind	GOS	19 Aug 2015
11	Jamsheed wind Energy (Pvt) Ltd	50	Wind	GOS	1 Oct 2015
12	Unicol Energy Limited	50	Wind	GOS	16 Oct 2015
13	Power China Houdang Engg Corporation	50	Wind	GOS	4 Feb 2016
14	Wuwei Aerospace New energy Investment Co Ltd	100	Wind	GOS	29 Feb 2016
15	Wuwei Aerospace New energy Investment Co Ltd	100	Wind	GOS	29 Feb 2016
16	Gul Ahmed Textile Mills Ltd	50	Wind	GOS	1 Mar 2016
17	Gul Ahmed Textile Mills Ltd	50	Wind	GOS	1 Mar 2016
18	Yunus Wind power Ltd (Y.B. Holdings)	50	Wind	GOS	1 Mar 2016
19	Lucky Wind power Ltd (Y.B. Holdings)	50	Wind	GOS	1 Mar 2016
20	Moro Power Company (Pvt) Ltd	25	Wind	GOS	1 Mar 2016
21	Western Energy (Pvt) Ltd(Sino well pvt ltd)	50	Wind	GOS	1 Mar 2016
22	Shafi Energy (Pvt) Ltd	50	Wind	GOS	2 Mar 2016

23	Orient Energy Systems (Pvt) Ltd	50	Wind	GOS	7 Mar 2016
24	Loctah Energy Ltd	50	Wind	GOS	7 Mar 2016
25	Lootah Energy Ltd	50	Wind	GOS	7 Mar 2016
26	Iran-Pak Wind Power (Pvt.) Ltd.	50	Wind	GOS	8 Mar 2016
27	Novatex limited	50	Wind	GOS	8 Mar 2016
28	Mustaqim Dyeing & Printing Industries	50	Wind	GOS	8 Mar 2016
29	Sindh Renewable Energy Company Pvt. Ltd	50	Wind	GOS	11 Sep 2017
30	Sindh Renewable Energy Company Pvt. Ltd	50	Wind	GOS	11 Sep 2017
31	Vestas Asia Pacific Wind Technology (Pvt) Ltd	250	Wind	GOPb	6 Mar 2016
		2139			
32	IPS Solar Park – IPS 22 (Pvt.) Ltd.	50	Solar	AEDB	3 Jul 2013
33	IPS Solar Park – JA 23 (Pvt.) Ltd.	50	Solar	AEDB	3 Jul 2013
34	IPS Solar Park – SB 24 (Pvt.) Ltd.	50	Solar	AEDB	3 Jul 2013
35	R.E. Solar I Pvt. Ltd.	20	Solar	AEDB	21 Apr 2014
36	R.E. Solar II Pvt. Ltd.	20	Solar	AEDB	21 Apr 2014
37	Janpur Energy Limited SPV: Jan Solar (Pvt.) Ltd.	12	Solar	AEDB	27 May 2014
38	Janpur Energy Limited	12	Solar	AEDB	27 May 2014
39	Siddiqsons Energy Karachi	50	Solar	AEDB	5 Dec 2014
40	ET Solar (Pvt.) Ltd.	50	Solar	AEDB	22 Apr 2015
41	ET Solar (Pvt.) Ltd.	25	Solar	AEDB	22 Apr 2015
42	ACT Solar (Pvt.) Ltd.	50	Solar	AEDB	6 Jul 2015
43	Asia Petrolium Limited	30	Solar	AEDB	3 Aug 2015
44	New Generation	200	Solar	GOS	17 Apr 2015
45	Meridian Energy Pvt Ltd	50	Solar	GOS	30 Apr 2015
46	HNDS Energy Pvt Ltd	50	Solar	GOS	30 Apr 2015
47	Helious Power Pvt Ltd.	50	Solar	GOS	30 Apr 2015
48	Metro solar power Ltd	50	Solar	GOS	4 May 2015
49	Technomen Kinetics/ZTE	20	Solar	GOS	22 May 2015
50	MI Solar	20	Solar	GOS	25 May 2015
51	Sukkur solar park Pvt Ltd	20	Solar	GOS	2 Jun 2015
52	Thatta Solar Park Pvt lld	20	Solar	GOS	2 Jun 2015
53	Al Tariq & Laguardia	20	Solar	GOS	30 Jun 2015
54	Gul Ahmed Energy Ltd	50	Solar	GOS	10 Jul 2015
55	National power & water company Pvt Ltd	50	Solar	GOS	3 Aug 2015
56	MCC New Energy Company(PK) Pvt Ltd	100	Solar	GOS	20 Aug 2015
57	Tricom solar power Pvt Ltd	50	Solar	GOS	28 Aug 2015
58	Siachen energy Ltd I-I	100	Solar	GOS	28 Aug 2015

59	Siachen energy Ltd -II	100	Solar	GOS	28 Aug 2015
60	China National Power Ltd	100	Solar	GOS	28 Oct 2015
61	Zhongxing Telecom pakistan Pvt Ltd(ZTE)	100	Solar	GOS	28 Oct 2015
62	Technomen Kinetics pvt Ltd	100	Solar	GOS	25 Nov 2015
63	Act 2 Solar Pvt Ltd	50	Solar	GOS	8 Feb 2016
64	Greenewable solar Pvt Ltd.	50	Solar	GOS	8 Mar 2016
65	IDC Pvt Ltd	50	Solar	GOS	1 Mar 2016
66	Siddiq Sons Limited	50	Solar	GOS	1 Mar 2016
67	Artistic Milliners Pvt Ltd	50	Solar	GOS	13 Apr 2016
68	Sindh Renewable Energy Company Pvt. Ltd	50	Solar	GOS	14 Jul 2017
69	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
70	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
71	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
72	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
73	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
74	Zonergy Company Ltd. (CPEC Project)	100	Solar	GOPb	3 Apr 2015
75	Zorlu Solar Pakistan Pvt. Ltd.	100	Solar	GOPb	17 Jan 2017
76	Zorlu Renewable Pakistan Pvt. Ltd.	100	Solar	GOPb	10 Jul 2017
77	Zorlu Sun Power Pvt. Ltd.	100	Solar	GOPb	10 Jul 2017
78	Zhenfa Pakistan New Energy Co. Ltd.	100	Solar	GOPb	19 Mar 2015
79	Solution De Energy	100	Solar	GOPb	12 May 2015
80	TBEA Xingiang (SPV - HUAGUANG Energy Pvt. Ltd.)	100	Solar	GOPb	4 Apr 2016
81	CWE &Welt Konnect (Pvt) Ltd. (Joint Venture)	50	Solar	GOPb	30 Apr 2015
82	Vogt Solar Ltd	15	Solar	GOPb	9 Jan 2018
83	Roshan Power (Pvt.) Ltd.	10	Solar	GOPb	23 May 2011
84	CK Solar, Korea	300	Solar	GOB	-
85	Enertech Holding Company	50	Solar	GOB	26 Oct 2016
86	Enertech Holding Company	50	Solar	GOB	26 Oct 2016
87	Nizam & Sons	50	Solar	GOB	28 Oct 2016
88	Nizam & Sons	50	Solar	GOB	3 Jul 2018
89	Canadian Commercial Company	50	Solar	GOB	-
90	EL-Passo Technology	50	Solar	GOB	26 Dec 2017
91	EL-Passo Technology	50	Solar	GOB	26 Dec 2017
92	Siddiqsons	50	Solar	GOKPK	28 Dec 2015
93	Siddiqsons	50	Solar	GOKPK	28 Dec 2015
94	Assal Solar Power	49.5	Solar	GOKPK	21 Jul 2016
95	FAS Energy	50	Solar	GOKPK	22 Sep 2016

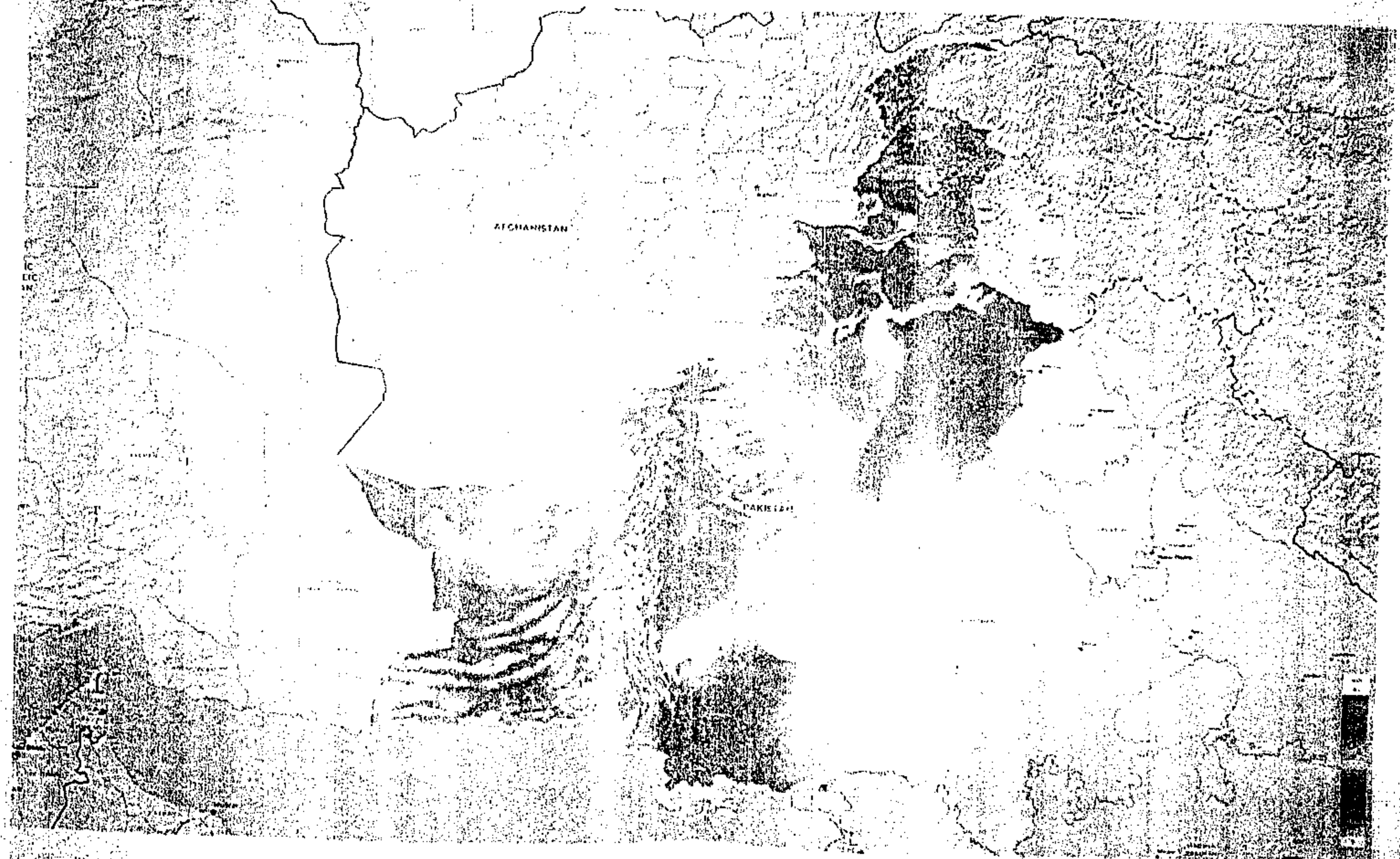
96	Target Energy	50	Solar	GOKPK	20 Oct 2016
		4143.5			
97	Safina Sugar Mills Ltd.	20	Bagasse	AEDB	9 May 2014
98	Alman Seyyam (Pvt.) Ltd.	34.5	Bagasse	AEDB	25 Jan 2017
99	Al-Mughni Industries (Pvt.) Ltd	40	Bagasse	AEDB	5 May 2017
100	Digri Gen Ltd.	25	Bagasse	AEDB	26 Apr 2017
101	Ranipur Energy (Pvt.) Ltd	60	Bagasse	AEDB	24 May 2017
102	Popular Energy Pvt. Ltd.	30	Bagasse	AEDB	15 Aug 2017
103	Hamza Sugar Mills (Unit-III)	15	Bagasse	AEDB	21 Jul 2017
		224.5			
104	Lahore Xingzhong Renewable Energy Co. Ltd.	40	MSW	GOPb	19 Oct 2016
	Total	6547			

ANNEX – B

GLOBAL WIND ATLAS

MEAN WIND SPEED AT 100m

PAKISTAN WIND POWER POTENTIAL



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01. 50X01 MW SOLAR POWER PROJECT OF P&G , IB-VOGT IN GWADAR

a. Balochistan Power Development Board (BPDB) Quetta on 23rd February, 2019 issued a Letter of Intent (LoI) to M/S IB-Vogt GMBH 50 MW Solar Power Plant in Gawadar.

b. The project secured tariff from NEPRA, Evacuation consent from Quetta Electric Supply Company (QESCO) Limited and NOC from EPA Balochistan

c. Projects is included in the Category-III as per decision of Cabinet Committee on Energy (CCoE).

02. 50X2 MW SOLAR POWER PROJECTS OF ENERTECH

a). M/S Enertech is a Kuwaiti Company and it formed two companies namely Enertech Bostan Solar (Pvt.) limited and Enertech, Quetta Solar (Pvt.) limited is a company formed to develop solar PV power project having capacity of 50 MW each in Bostan, district Pishin.

b). In the year 2018 the company expressed its interest in establishing 02 Solar Power Projects of 50 MW Each in Balochistan. In 2018 the Balochistan Power Development Board (BPDB) issued the Letters of Intent (LoI) to the Company for establishment of 2x50 MW Solar Power Plants in Bostan.

c). Land has been allotted to the project company by Government of Balochistan and the project got NOC from the Environment Protection Agency Balochistan, and the Tariff determination from NEPRA .

d) Both the projects are included in the Category-III as per decision of Cabinet Committee on Energy (CCoE).