National Transmission & Despatch Company Ltd.

Deputy Managging Director (System Operation)

No.433-37 /DMD (SO)/RA/ NEPRA Dated: 01-09-2023

Registrar,
National Electric Power Regulatory Authority,
NEPRA Tower, G-5/1,
Islamabad

Subject: Authority Directions w.r.t. submission of System Needs Assessment Report to enhance reliability & stability of National Grid for Security Constrained Economic Dispatch.

It is apprised that The Authority during Monthly Fuel Charge Adjustment (FCA) hearing of July 2023, directed System Operator to share a detailed Report of the challenges System Operator is facing with respect to network stability, reliability which subsequently is hindering effective utilization of economical plants. It is worth mentioning that this office has already submitted a comprehensive System Needs Assessment (SNA) report vide letter No. 297-298/DMD(SO)/NPCC Dated June 14, 2023 to MoE (attached herewith as Annex-A), where vulnerable areas in network and subsequent constraints of the system have been highlighted.

System Needs Assessment report is prepared in accordance with Grid Code 2023 & System Operator License (specifically as per Section 3, Section 22 & Section 33). The report highlights two key vulnerable areas of grid system i.e. The Southern Grid and Lahore Ring. Report also mentions the limitation to fully utilize HVDC link until adequate reactive power compensation is not provided on AC corridor. Effective & optimum availability of operating reserves (as mandated under Grid Code 2023) is also been presented in report.

During the hearing, Worthy Chairman of The Authority also highlighted the importance of improved demand forecasting, in this regard a Deviation Settlement Mechanism (DSM) is proposed in report to improve demand forecasting by DISCOs. Additionally, a trial has also been started to provide real time forecast error by wind farms.

It is worth mentioning that after issuance System Operator License where Power System Planning function has been allocated in domain of System Operator, The System Operator is actively carrying out its capacity building to carry out functions of Planning in close coordination with Power System Planning department of NTDC.

Ali Zain Banatwala
Deputy Managing Director (System Operation)
NPCC, NTDC, Islamabad

Copy to:

1. Managing Director, NTDC, WAPDA House Lahore.
2. General Manager (System Operation, NPCC, NTDC, Islamabad.
3. Chief Executive Office, CPPA (G), Islamabad.
4. PS to Chairman NEPRA, Ataturk Avenue, Islamabad.

National Transmission & Despatch Company Ltd.

Dy. Managing Director (System Operation)
National Power Control Centre.

No. 297-298/DMD(SO)/NPCC

June 14th, 2023

Secretary Power Division
Ministry of Energy
Islamabad

Subject: System Needs Assessment

The attached Technical Note on System Operation entitled "System Needs Assessment" is prepared in accordance with the Grid Code and the System Operator License, specifically Article-3 (Functions of the Licensee), Article-22 (Power System Planning) and Article-33 (Administration of Ancillary Services).

The Technical Note provides a roadmap to supplement the Transmission System Expansion Plan (TSEP) to ensure that in addition to interconnection of new generators and removal of constraints, system security and reliability needs are addressed and that economic merit order violations are reduced.

Two Vulnerable Areas are highlighted – the Southern Grid and the Lahore Ring. Increasing wind power generation capacity without adequate wind forecasting, without adequate Operating Reserves and without addressing the vulnerabilities in the South would lead to increased wind power curtailments. Similarly, the HVDC link cannot be utilized to its full capacity until and unless adequate reactive power compensation is provided on the AC Corridor and on the Lahore Ring.

The Technical Note also proposes a roadmap for Operating Reserves (Ancillary Services), a load forecast Deviation Settlement Mechanism for DISCOs (like the one implemented in India), and wheeling of power by KE from Jamshoro Unit-1.

Ali Zain Banatwala
Deputy Managing Director (System Operation)

Copy to:

- Additional Secretary I, Power Division, Ministry of Energy, Islamabad
- *Master File*

TECHNICAL NOTE ON SYSTEM OPERATION

SYSTEM NEEDS ASSESSMENT

NATIONAL POWER CONTROL CENTRE

JUNE 2023

1. Power system reliability is defined as the probability that an electrical power system can perform a required function under given conditions for a given time interval. Power system reliability consists of power system security and power system adequacy. An adequate power system has sufficient generation, transmission and distribution facilities in the system to satisfy aggregate energy demand taking into account scheduled and unscheduled outages of the system components. System security on the other hand describes the ability of the system to handle disturbances, such as the loss of major generators or transmission facilities.

2. A vulnerable system is a system that operates with a reduced level of security. A Vulnerable Area is a specific section of the system where vulnerability begins to develop. The occurrence of an abnormal contingency and highly stressed operating conditions define a system in the Verge of Collapse State. Vulnerable Areas are characterized by five types of system stress: transient instability, poorly damped power oscillations, voltage instability, frequency deviations outside permissible limits and thermal overloading, i.e., congestion.

3. Deviation from the Economic Merit Order (EMO) is commonly referred in the industry as a "redispatch". Redispatch is required if the market-clearing / EMO-based generation schedules result in Vulnerable Areas. In case of congestion or stability constraints, redispatch shifts generation away from export-constrained zones to import-constrained / unconstrained zones.

4. The primary focus of power system planning in NTDC in recent years has been interconnection of new generators, removal of system constraints and associated transmission expansion plans which are either inadequate or delayed in their implementation which has comprised system security. As a result, two permanent Vulnerable Areas have been inadvertently created, i.e., the Southern half of the 500kV network (which includes the AC Corridor) and the Lahore ring.

Vulnerable Area 1: Southern network

5. Jamshoro grid station is a one of the most important nodes in the network. It is the:
   a) Sole transit point for cheap power generated by K2, K3, China Power Hub and Hubco to meet demand in the north.
   b) One of two transit point for Port Qasim, Lucky and Thar coal power plants using the AC Corridor after maximum utilization of HVDC Available Transfer Capacity (ATC).
   c) Only transit point for evacuation of wind power from Jhimpir/Gharo (after transformation from 220kV to 500kV).
   d) Primary common delivery point (CDP) for supplying power to HESCO and one of two CDPs for KE with the national grid (up to 350 MW on 220kV via Jhimpir-2 to KDA).

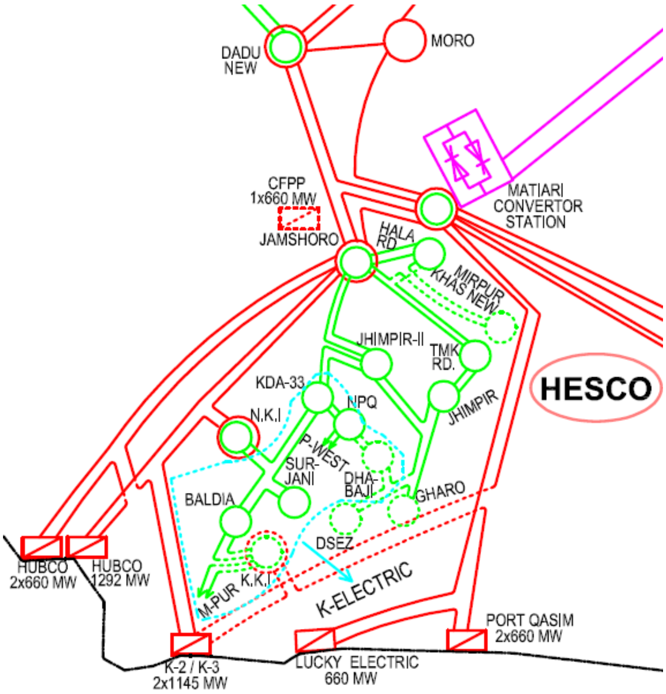

Figure 1: Southern network

6. Jamshoro grid station is a major congestion point due to both insufficient incoming and outgoing transmission capacity. All bulk power generation that is either directly or indirectly connected to Jamshoro lies in an export-constrained zone. This includes:
    a) Direct (on 500kV): K2 (1050 MW), K3 (1050 MW), China Power Hub (1250 MW)/HUBCO (1200 MW) less KE demand at NKI (-850 MW) = 3700 MW
    b) Direct (after step-up transformation from 220kV): Wind IPPs (1845 MW)
    c) Indirect via Matiari (on 500kV): Thar coal (2400 MW), Lucky (600 MW), Port Qasim (1250 MW) = 4250 MW

7. Due to *oscillatory stability* concerns, power flow is limited to 800 MW on the Jamshoro-Dadu circuit (which is tri-bundle) and 1000 MW on the two Jamshoro-Matiari circuits (which are quad-bundle). To maintain N-1 contingency compliance, total power flow on this section (known as AC Corridor Interface-1) is restricted to 1800 MW under normal conditions. In case any of these three circuits is unavailable, loading is restricted to 800-1000 MW.

8. Due to *transient stability* concerns, the Available Transfer Capacity (ATC) from south to north on the combined AC/DC Corridors is restricted to 4500 MW in summer and 2500 MW in winter under normal operations (**Annex 1**). Under maintenance mode, the limits reduce to 2000 MW in winter. Therefore, if AC Interface-1 is loaded at 1800 MW, the maximum loading for the HVDC line would be 2700 MW, i.e., 1300 MW of HVDC capacity would be unutilized. Conversely, if HVDC is carrying 3200 MW, AC Corridor section-1 would be restricted to 1300 MW. **Annex 2** contains the EMO-based generation dispatched in the North and South from 10 GW to 20 GW. For example, if generation is 10 GW, 4784 MW should be dispatched in the south as per EMO. However, since ATC is only 2500 MW in winter, 2284 MW has to be redispatched in the North.

EMO-based day-ahead unit commitment	6350 MW (Thar Coal, K2, K3, China Power Hub, Lucky)
Wind power generation forecast	1500 MW
Demand	-500 MW (HESCO) -1100 MW (KE)
Transfer capacity required	6250 MW
Available Transfer Capacity (ATC)	4500 MW (2700 DC, 1800 AC)
SCS[1] tripping strategy (bipole failure)	2640 MW (Engro Thar, TEL, SECL, Thal Nova)
SCS tripping strategy (monopole failure)	990 MW (Engro Thar Unit-1, SECL Unit-1)
Redispatch / curtailment	1750 MW (China Power Hub, Lucky / wind power)

Table 1: Export constraint example under normal operating conditions (all lines in service)

9. Jamshoro grid station is also extremely vulnerable due to its ageing infrastructure:
    a) Transformer T1 was installed in 1987, T2 in 2007 and T8 in 2020. T8 has an ongoing problem with its tertiary busbar which fails periodically resulting in wind power curtailments.
    b) The 220kV yard dates back even further, with T3 installed in 1984 and T7 in 2003.
    c) Shunt reactors: 2 x 66 MVAR was installed in 1987, 2 x 66 MVAR in 1995 and 3 x 111 MVAR in 2007, 2018 and 2021.
    d) The two oldest 500kV circuits connected to Jamshoro date back to 1987, i.e., Jamshoro-Dadu and Jamshoro-Matiari-Dadu.

10. In addition to the technical vulnerabilities due to ageing infrastructure, Jamshoro grid station is also understaffed. 37 operations staff and 33 maintenance staff are sanctioned whereas the actual deployment is 20 operations staff and 13 maintenance staff. (**Annex 3**).

11. As explained in paras 5-8, all bulk power generation connected directly or indirectly to Jamshoro grid station lies in an export constrained zone. Any additional power generation (e.g., Jamshoro coal Unit-1 or 500 MW wind power) would only result in additional redispatch and curtailment. It should be noted that due to its location on the 500kV AC Corridor, Jamshoro CPP Unit-1 is beneficial for system security. Operating Jamshoro CPP Unit-1 would improve both transient (rotor-angle) stability and oscillatory stability. However, as it is an export constrained zone, operating Jamshoro CPP Unit-1 may require offsetting the equivalent power from Thar Coal.

12. A 100km 500kV double circuit transmission line from K3 up to the existing double circuit from Port Qasim / Lucky to Matiari is currently under construction. These two new circuits would improve network capacity and redundancy (N-1 contingency compliance) south of Jamshoro. However, the new circuits do not alleviate the export capacity constraints on the AC Corridor.

13. KE's transmission investment plan has the potential to reduce power exports from the south by increasing local consumption of southern power generation:

[1] SCS (Stability Control System) is a Special Protection Scheme designed to trip generators in the south in case the HVDC link fails or is temporarily blocked. The instantaneous increase in power flow on the AC Corridor would result in an increase in load angle past the transient (rotor-angle) stability limit. Without generator tripping, the generators north of the AC Corridor would lose synchronism with the generators clustered in the south. To avoid network protections tripping the AC Corridor forming two unconnected unstable islands, the SCS trips generators to reduce the load angle on the AC corridor.

KKI	900 MW	This grid station is to be looped in/out on one of the two new transmission lines being constructed by NTDC described in para 12.
NKI	1100 MW	Presently 2 x 600 MVA 500/220kV autotransformers are installed and up to 850 MW is drawn by KE. As per KE's investment plan, installation of a third 600 MVA transformer at a cost of PKR 7.604 billion would increase capacity to 1100 MW (with N-1 contingency compliance). However, this does not consider the rating of the connecting transmission lines, i.e., K2/K3-NKI and NKI-Jamshoro. The maximum rating of the shorter, heavier loaded line from K2/K3 to NKI is 1350 MW. The conductors for these two transmission lines would also have to be replaced (at KE's cost). This cost is not included in the transmission plan submitted to NEPRA.
Jhimpir-2	500 MW	ATC restricted to 350 MW due to thermal rating of the 220kV transmission lines, not 500 MW.
Dhabeji	350 MW	direct interconnection of wind and solar plants to KE on 220kV. Also connected to NTDC 220kV network via Dhabeji SEZ. This connection does not impact the 500kV Southern Network from an export constraint perspective.

14. Increasing tie-lines with KE would not change the Available Transfer Capacity on NTDC's AC/DC Corridors. However, it would increase the capacity factor for some of the cheaper (baseload) generation located in the south as it would then be used to serve Karachi's demand instead of being constrained-off due to insufficient ATC.

15. KE's investment plan states that the enhancement in interconnection capacity is necessary to evacuate power from 82 MW hydropower plant (in KPK) and 330 MW Thar Coal power plant. As per NEPRA's Open Access Regulations, NTDC must allow wheeling on its network. Wheeling of power from 82 MW HPP is not a concern as the contract path is in the opposite direction of network congestion. There is presently no interconnection scheme for 330 MW Thar Coal power plant. Wheeling on the existing 500kV lines would have to be studied for N-1 contingency compliance. In case curtailment of the existing power plants is required in an N-1 contingency case, the cost would be allocated to KE on a Last-In-First-Out (LIFO) basis.

16. Interconnection of Jamshoro CPP via Jamshoro grid station increases the risk associated with the ageing and vulnerable infrastructure. Without an increase in export capacity or net increase in demand in KE or HESCO, any additional generation transiting via Jamshoro would be redispatched (thermal) or curtailed (wind).

17. The system needs a new 500kV grid station in the South. The new grid station (NGS) would de-risk Jamshoro by interconnecting with existing 500kV transmission lines. Step-up transformation from 132kV/220kV to 500kV can be used to connect new wind farms. The 220kV busbar may be used to supply KE through looping/in out of the existing Jhimpir2-KDA transmission lines or through additional 220kV lines. With 4 x 200kV circuits, KE's 330 MW Thar Coal power plant may also be connected to this grid station, so that it may serve KE's load directly with N-1 contingency compliance.

18. The export constraints or the stability constraints on the AC Corridor can only be resolved by constructing new 500kV transmission lines with adequate VAR compensation. Without the

additional AC transmission lines, EMO violations cannot be avoided, and system security cannot be improved.

a) Option 1: 500kV single/double circuits to Shikarpur. One 500kV bay is readily available at Shikarpur.
b) Option 2 (Figure 2): 500kV single/double circuits to Rahim Yar Khan (via Moro).

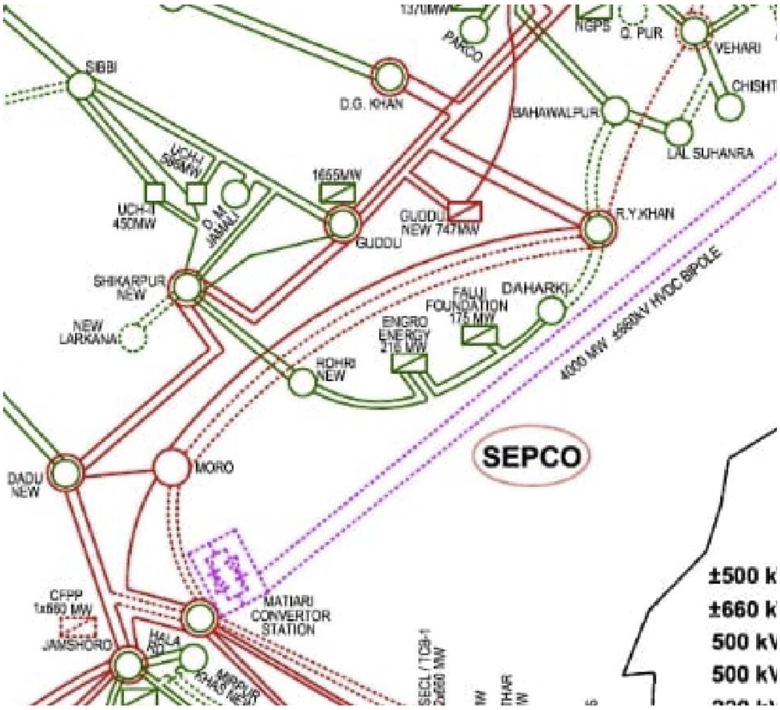

Figure 2

19. Expanding Total Transfer Capacity on the AC Corridor would also increase Available Transfer Capacity on the DC Corridor as it would increase the stability margin for instantaneous power transfer from DC to AC in the event of an HVDC failure or blocking event. The overload capacity of a single monopole is 2200 MW. Therefore, to avail the full 4000 MW capacity of the HVDC link, the capacity of the AC Corridor must at least be increased to absorb an additional 1800 MW transfer from HVDC (in case of a monopole failure) without causing transient instability, poorly damped power oscillations, or thermal overloading (congestion).

20. It should be highlighted that Option 2 (Figure 2) was included in the system expansion plan for 2025/26 prepared by Planning Department in 2021. However, the latest expansion plan for 2025/26 does not include this line. As per feedback from the Planning Department, the line has been postponed indefinitely due to budget limitations.

21. In case NTDC is unable to commit funds to either build a new substation to de-risk Jamshoro or build new transmission lines to expand the Total Transfer Capacity, the Sindh Transmission & Despatch Company (STDC) and/or private investors may be approached. Section 4.3 of NEPRA's Open Access Regulations 2022 states that:

(3) In the event where network licensee shows its inability to construct the interconnection facilities due to technical and/or financial constraints following options may be exercised for the interconnection purposes:

(a) The generation company may arrange the financing required for the construction of interconnection facilities by the network licensee. The network licensee and generation company shall enter into an agreement to mutually decide the terms and conditions for reimbursement of financing to the generation company; or

(b) A special purpose company, may construct, operate and maintain the dedicated network and interconnection facilities for connecting with the national grid after obtaining relevant licence from the Authority.

22. <u>It is important to note that expanding the active power Transfer Capacity requires the equivalent investment in reactive power compensation in both Vulnerable Areas.</u> The capacitive effect of lightly loaded transmission lines (typically when system load is below 15000 MW) raises voltages on the AC Corridor (D.G.Khan, Muzaffargarh, RYK). Without reactive power compensation, the System Operator is forced to remove 500kV transmission lines from service as a voltage reduction measure. Removing transmission lines from service increases the network's impedance making the system vulnerable to both oscillatory instability (under normal operations) and transient instability (after large disturbances such as a generator tripping). Removing transmission lines also creates congestion, violates N-1 contingency compliance and generally weakens the system.

Vulnerable Area 2: Lahore Ring & HVDC Commutation Failure

23. For line-commutated converter (LCC)-based high voltage direct current (HVDC) systems, commutation failure (CF) is a frequent dynamic event that takes place at the inverter side, i.e., Lahore Converter Station (LCS). It is caused by AC system faults. CF leads to a temporary cessation of active power transfer. In asynchronous power systems connected through an HVDC link, CF can severely impact the frequency stability of the AC systems. In the case of the Pakistani power system, Matiari-Lahore is an *embedded* DC link as it is connected to the same synchronous power system at both ends. Therefore, while a CF event does not cause a frequency event, the instantaneous transfer of power to the AC Corridor results in other security violations that have already been listed in para 22.

24. Under normal HVDC operation, the operation point is determined by constant current (CC) control at the rectifier and constant extinction angle (CEA) control at the inverter. The occurrence of commutation failure is related to the transformer reactance, operating extinction angle, smoothing reactor characteristics, and short circuit ratio (SCR). It may occur frequently at the inverter side because of the low extinction angle. In addition, the probability of its occurrence increases if an AC system connected to the inverter has low SCR owing to the weak AC network. However, these parameters are primarily determined pre-construction. Since the SCR depends on proximity of voltage sources, the SCR is lower in winter when fewer RLNG power plants are in operation. To ensure voltage stability in winter, an alternate source of short-circuit power such as enhanced (super capacitor equipped) Static Synchronous Compensators (STATCOM)s or battery energy storage systems (BESS) are required.

25. A single CF event may last between 40 and 200 milliseconds. However, if the AC system fault at the receiving end (Lahore side) is not cleared in time, it may result in subsequent commutation failures, reduction of DC transmission power, DC bias of converter transformer, and voltage instability of the weak AC system on the inverter side causing additional successive CF events. Reactive power balance of the converter station may also be upset after AC faults, resulting in excess reactive power or insufficient reactive power which is a deterrent to system recovery and may also lead to subsequent commutation failures. The Matiari-Lahore DC link is designed to block after three successive CF events.

26. CF mitigation from HVDC modification such as improving the critical extinction angle (CEA) to advance the firing angle is difficult once the system is in operation. Therefore, the only option for CF mitigation is to stiffen the AC system near LCS, as recommended by PMLTC in the Joint Working Committee on CF mitigation. It is important to mention that it is not just faults on the NTDC network that result in CF events. In fact, a large percentage of CF events are due to faults occurring in the LESCO 132kV network. A list of CF events from January to May 2023 are listed in **Annex 4**.

27. The primary mitigation measure for reducing CF is dynamic reactive power compensation from Flexible AC Transmission Systems (FACTS) devices such as Static VAR Compensators (SVC) and STATCOMs. There is currently a 450 MVAR SVC installed at 132kV Kot Lakh Pat grid station. However, this is insufficient to regulate the voltage on the entire Lahore Ring. In addition to a high SCR, the System requires:

    a) Delicensed generators converted to synchronous condensers. Feasibility studies should be conducted for synchronous condensers at Guddu, Muzaffargarh and Jamshoro.
    b) STATCOMs for the Lahore Ring for fast voltage regulation to avert CF. The exact amount of reactive compensation that is required will be established by the CESI Study on system stability. That Study is expected to be completed by October 2023. Enhanced STATCOMs provide rapid voltage support as well as increase of system strength and system inertia. An indicative non-binding estimate (on FOB basis) for a 400 MVAR STATCOM (without any civil, installation/site works etc. and without duties & taxes) is ca. USD 36 million whereas the cost for a 400 MVAR enhanced STATCOM is ca. USD 58 million.

28. Despite the System Need for reactive compensation, the System Operator is wary of NTDC's ability to adequately maintain FACTS devices. Firstly, Asset Management is grossly underfunded – <u>only PKR 2.046 billion was allocated to Repair & Maintenance out of the operating budget of PKR 74.343 billion for 2022/23.</u> Secondly, the Asset Management department consists primarily of Grid Station Operator (GSO) staff that lack the requisite expertise in power electronics (PE) and FACTS devices. The chequered history of the "pilot" SVC installed at Kot Lakh Pat[2] serves as a cautionary example. It is currently operating

[2] The contract was signed with ABB in January 2011 with a delivery period of 18 months. The contractor received the project completion certificate in January 2106 (invoking the five-year warranty period) but NTDC was unable to provide the 132kV busbar until two years later. Energisation finally took place on 14.05.2018. After suffering 17 outages in 20 months, the contractor went into dispute when the 18th outage took place in January 2020. After 23 months, the SVC was eventually reenergized on 24.11.2022. It suffered yet another outage on 04.01.2023. It was last reenergized on 28.03.2023.

without sufficient spare parts and no mechanism exists for the supply of spares. Once the spares run out the SVC will stop operating which would be extremely detrimental to voltage stability on the Lahore ring as well as to the HVDC system.

29. NTDC also lacks the technical expertise to design (EMT, RTDS) and tender (evaluate technical bids) fast switching PE-based transmission systems such as HVDC or FACTS devices. Despite the SVC contract being signed in 2011 and in operation since 2018, no FACTS expert is to be found in the company. Therefore, it is recommended that a subsidiary company with experts in power electronics be considered for the complete lifecycle of FACTS devices. This specialised company could have a business model such as NESPAK's, whereby it may eventually target business outside Pakistan. Incidentally, NTDC has already established a company by the name of Transerv Private Limited in 2017. Rapid global deployment of HVDC, FACTS and PE-based generation (i.e., inverter-based generation such as wind and solar) is an opportunity for NTDC to tap the burgeoning international market for technical experts and project consultants in power electronics. Power Grid India is already benefitting from international projects using this business model.

30. The first version of the Transmission System Expansion Plan (TSEP) covering new projects up to the year 2025-26 was prepared by Planning Department with the help of USAID's Power Sector Improvement Activity (PSIA) program in 2022. The TSEP recommends 450 MVAR SVC/STATCOM in the QESCO area and 17 x 100 MVAR switched shunt capacitors in various areas to address low voltage concerns and reduce transformer loading. Switched capacitors only provide steady-state voltage support. They do not provide dynamic voltage support needed for mitigation of CF events which occur after AC system disturbances. Only dynamic reactive compensation elements such as STATCOMs can provide the requisite voltage stiffness required adjacent to Lahore Converter Station to mitigate CF. Switched capacitors on the Lahore Ring (132kV Ravi, Ghazi Road, Wapda Town, Punjab University and Lahore North) may not be needed once the requisite STATCOMs are installed. As per feedback received from PSIA, additional dynamic reactive compensation devices (FACTS) would be identified in TSEP 2023, studies of which are currently underway.

Table 5.20: Newly Proposed Projects for Voltage Control and Reliability Improvement

Sr. No.	Name of Project	Project Description	Expected Completion Date	Estimated Cost (MUSD)
1	250 MVAR SVS at 132 kV Quetta Industrial	100 MVAR Switched Shunt	2023-24	22.5
		+150, -150 MVAR STATCOM	2024-25	
2	200 MVAR SVS at 132 kV Khuzdar	100 MVAR Switched Shunt	2023-24	16.3
		+100, -100 MVAR STATCOM	2024-25	
3	Reactive Power Compensation at 220 kV and 132 kV Grid Stations	100 MVAR Switched Shunt each at 132 kV Ravi, Ghazi Road, Wapda Town, Punjab University, Lahore North, Lalian New, Nishatabad, Nokhar, KAPCO, Piranghaib, Bahawalpur, Sahuwala, Jaranwala Road, Yousafwala, Vehari, Mastung and 220 kV Kala Shah Kaku	2023-24 & 2025-26	47.6
4	Mitigation of high fault level at 132 kV Burhan	16 Ohm inter bus Current Limiting Reactor (CLR) between 132 kV bus bars of Burhan 220/132 kV Grid station	2025-26	1.0
			TOTAL COST	87.4

Table 2: TSEP 2022 (Phase-1) proposed projects for voltage control & reliability improvement

Ancillary Services

31. The System Operator License issued by NEPRA defines Ancillary Services as system services that are required to operate and maintain power quality and a stable and reliable power system including reactive power support, operating reserve, frequency control and black start. Article 33 states that "the Licensee shall purchase or otherwise acquire ancillary services from the most economical sources available to it, keeping in view the quantity and nature of the services required to ensure system security."

32. OC 5.4.13.1 of the Grid Code states that "The SO shall determine any reserve requirements, including the amount of Primary Operating Reserve, Secondary Operating Reserve and Tertiary Operating Reserve to ensure system security. For such reason, within twelve (12) months of the approval of this Grid Code, the SO shall establish, and maintain permanently updated, GCOP for Operating Reserve Requirements, detailing the methodology to be used to determine the amounts of different types of reserve required by the Transmission System in different operational conditions."

33. The System Operator has entered into a technical assistance agreement with National Renewable Energy Laboratory (NREL) to conduct a gap assessment of its Operations Planning processes and to conduct a detailed analysis and recommend the optimal mix of Operating Reserves required to maintain load-frequency control. The analysis will also be applied to a higher penetration of VRE generation. Discussions are also underway with USAID and with Energinet, the Danish Transmission System Operator (TSO), to support the System Operator in developing a framework for procurement, prequalification, and compliance testing for delivery of ancillary services.

34. Many of the properties of the power system, including its generation output, load levels, and transmission equipment availability are both variable and unpredictable. Therefore, additional generation capacity is made available either on-line or on-standby. This capacity, herein referred to as operating reserves, is principally divided into two categories – non-event reserves and event reserves. Non-event Reserves are Spinning Reserves that include Regulating Reserves (fast) and Load Following Reserves (slower) that are used to correct imbalances during normal conditions. Event-based (Contingency) reserves are generally divided into three groups – Primary Reserve, Secondary Reserve and Tertiary Reserve.

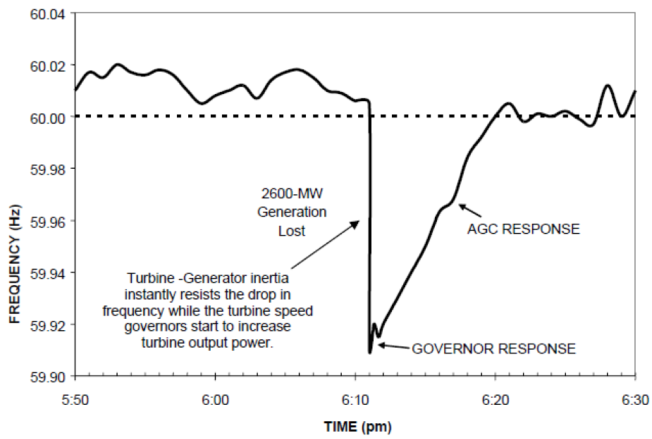

Figure 3: Primary Reserve and Secondary Reserve (AGC)

Service / Purpose	Control Requirement	Response (OC 5.4)	Current practice / compliance
Primary Reserve: Post-event frequency containment	**Automatic** (Power Plant): Under FGMO[3], the turbine speed controller responds to instantaneous active power imbalances for frequency excursions outside the dead-band.	Reach max value within 10 seconds; sustainable for 30 seconds	FGMO tests listed in the PPAs are inadequate. The plants that do have FGMO active have a very wide dead-band (49.5Hz-50.5Hz) due to the excessive frequency excursions. Compliance monitoring by SO has revealed frequency response is not being provided. (**Annex 5**)
Secondary Reserve: A) Post-event frequency restoration to 50 Hz; and B) Regulating Reserve under normal conditions	**Automatic** (System Operator): SCADA signal known as Automatic Generation Control (AGC).	Response time of 5 seconds; reach max value within 30 seconds; sustainable for 30 minutes	AGC is unavailable due to inadequate SCADA connectivity. As a result, Secondary Reserve continues to be dispatched manually.
Tertiary Reserve: Replaces Secondary Reserve	**Manual** (System Operator)	Depends on power plant's ramp rate & start time.	Manual dispatch. Include both spinning and non-spinning reserves.

35. The current modus operandi of System Operation is as follows:

Timeframe	Purpose	Modus Operandi
Day-Ahead	Indicative Operating Schedule (IOS)	Power plant and transmission network availabilities, generation costs (merit order), DISCO demands, etc. are fed into NCP unit commitment software. Tarbela, Mangla and Ghazi Barotha HPPs are optimized to ensure full energy utilization over the coming twenty-four hours.
Real-Time: normal conditions	Load-Following / Regulation	Dispatcher faces many challenges in minimizing deviations from IOS: 1. DISCO day-ahead demand forecasts are completely inaccurate. 2. HVAC/HVDC corridor capacity constraints and SCS tripping requirement. 3. Thermal constraints, low power factor and low voltages. Forced outages of power plants and transmission lines creates new constraints. 4. IRSA makes ad hoc intraday changes to Tarbela & Mangla indents. 5. Wind power has a large forecast error. 6. During peak demand when Tarbela, Ghazi Barotha & RLNG plants are fully utilized, fast responding upward regulation is exhausted. Therefore, Load Management has to be recalculated in response to the frequency deviations.
Real-Time: contingency	Frequency Containment & Restoration	On a generator tripping event, the frequency drop is contained by Automatic Under Frequency Load Shedding (AUFLS) which starts at 49.4 Hz and continues in eleven stages until 48.5 Hz for a total 25% of system load, Rate-of-Change-of-Frequency (RoCoF)-based Load Shedding. Frequency Restoration comprises of power plant redispatch and manual Load Shedding by Regional Control Centre (RCC) North.

[3] Free Governor Mode of Operation (FGMO)

36. Operating Reserves have historically not featured in system operation. Although the generation adequacy problem has now largely been addressed, (the occasional fuel shortages aside), neither Primary Reserve nor Secondary Reserve is currently available. Dispatch commands are relayed manually via telephone. As a result, the system frequency varies from 49.5 Hz to 50.5 Hz during normal operating conditions.

37. The generation stack (ca. 40,000 MW) is skewed towards baseload thermal generation, hydropower which is seasonal, and variable renewable energy (VRE). There is a notable scarcity of Regulation / Load-Following generators. Generators that could be used for Regulation do not have an open cycle tariff. This creates major problems in system operation.
    a) Summer demand of 20,000 MW less 10,000 MW baseload = 10,000 MW that can be attributed to cooling demand which is weather driven.
    b) Approx. 2000 MW of variable and intermittent wind and solar power generation further complicates operations planning and real-time system operation.
    c) Increasingly occurrences of freak weather which drops system demand by as much as 40% as cooling demand recedes.

6th June 2023: high winds, hail	System generation was 18,000 MW at 15:30 and expected to climb to 20,000 MW at 19:30. However, as windstorms gathered in SEPCO, MEPCO, FESCO and LESCO, system demand fell abruptly, and generation was reduced to under 15,000 MW.
10th June 2023: high winds	System generation dropped from 21,263 MW at 14:45 to less than 12,500 MW by 18:45 – a drop of more than 40% in three and a half hours! LESCO's load reduced from 4,350 MW to 1,630 MW and GEPCO reduced from 1,850 MW to 630 MW.

Figure 4: hailstorm in T.M.Khan on 30th May 2023

38. Since it is not possible to operate a power system without Load-Following, baseload thermal generators are utilized for Load-Following. This leads to increased wear and tear as baseload generators are not designed to be ramped up and down multiple times a day to follow the daily load pattern. A complaint from Lucky coal power plant is attached as **Annex 6**. NEPRA in fact considers not using a thermal generator at full capacity as "inefficient" use of generation that incurs Part-Load Adjustment Costs (PLAC). Alternatively, the System Operator could increase the number of start-ups and shutdowns. However, this would lead to even further

plant degradation and even higher costs as the cost of a start-up for a single 660 MW coal-fired generator can range from USD 80,000 to USD 220,000 depending on its idle time.

39. IPPs and GENCOs equipped with FGMO are for the most part either unwillingness or wary of providing the requisite Primary Reserve due to the wide variation in the system frequency and the inadequate coverage of FGMO tests in the approved technical schedules of PPAs[4]. Furthermore, Primary Reserve cannot be sustained without replacement by Secondary Reserve. AGC connectivity for all power plants will take at least one year after the completion of the SCADA-3 project.

40. Power System Stabilizers (PSS) have been installed at all major power plants, but they have not been tuned for inter-area oscillations. Without a wide-area monitoring system (WAMS) based on synchronized phasor measurements, it is not possible to tune the PSS to damp inter-area oscillations or even to know when oscillations occur other than direct observation in the system frequency. By then it may be too late if the oscillation is undamped. Physical tests at certain participating generators would also be required.

41. The majority of wind power plants (WPPs) do not have binding forecasts in their energy purchase agreements (EPAs). Only the most recently commissioned 12 WPPs have binding forecasts and forecast error penalties (on an annual basis). These EPAs place the wind risk on the seller. The forecast is to be provided four hours ahead and updated at the top of each hour. The remaining 24 WPPs either have no binding forecast or no forecast at all. In terms of real-time forecast error, NPCC is almost in the dark as it receives real-time data from only 4 WPPs. As a result, it is next to impossible to track the real-time wind power generation or the forecast error four hours prior to dispatch.

42. Given the current operating limitations described in paras 34-41, the addition of further VRE generation without improving VRE forecasting and real-time forecast error, especially wind power in the Vulnerable Area in the south, will further reduce power system security.

43. The System Operator proposes the following solution for improving system security and reliability:
    a) **VRE**: Grid Station-wise aggregated forecasts and real-time forecast error to be provided by the wind farms. A trial has started this month.
    b) **DISCOs**: A Deviation Settlement Mechanism (DSM[5]) like the one implemented in India to improve the load forecasts submitted by DISCOs.
    c) **Primary Reserve**: Battery Energy Storage System (BESS[6]) for fast frequency response. Simulation studies to determine the exact quantum will be conducted once the CESI study is completed. At least a 500 MW BESS is required in the south.

[4] In some cases, the Technical Schedules are still unapproved.

[5] T. Bharath Kumar, Anoop Singh: "Ancillary services in the Indian power sector – A look at recent developments and prospects", Energy Policy, Volume 149: "The DSM is one of the regulatory mechanisms to achieve the grid stability, reliability and security by imposing penalties and incentives for over drawl/injection and under drawl/injection from the schedule. The DSM has achieved the grid discipline in terms of consumption as per schedule across the distribution companies. The deviation charges are primarily linked with the volume of deviation and corresponding frequency during such drawl/injection scenarios."

[6] A 20 MW pilot project at 220kV Jhimpir-1 grid station is scheduled for completion in April 2024 but will likely be delayed.

44. The immediate System Need is Primary Reserve (frequency bias) and regulation of interface flows on the stability-constrained 500kV AC Corridor (tie-line bias). Unlike a power plant which takes a few seconds to provide Primary Reserve, a BESS can provide full power output near instantaneously (100-200 milliseconds). The BESS would be configured to operate in the Tolerance Frequency Band whereas the generators on FGMO would be configured to operate in the Frequency Sensitive Band with a slight overlap. This would allay many of the concerns of the power plants as the excursions outside the Frequency Sensitive Band would be greatly reduced.

Table OC 2: Operating Frequency Limits

Sr. No.	Description	Frequency Limits
1	Target Frequency	50 ± 0.05 Hz
2	Frequency Sensitive Band	49.8 Hz to 50.2 Hz
3	Tolerance Frequency Band	49.5 Hz to 50.5 Hz
4	Contingency Frequency Band	49.3 Hz to 50.5 Hz

45. Large-scale introduction of solar power in MEPCO region at 220kV and especially at 500kV would also benefit from BESS support. In addition to Primary Reserve, the MEPCO-located BESS would also provide short-circuit power and smoothen out the variability of solar power during cloudy spells for regulation of interface flows on the 500kV AC Corridor.

46. The fact that manual frequency regulation from RLNG-fired CCGTs and hydropower plants is only available in the north whereas wind power plants, a major source of variability are in the south, render manual frequency regulation a security risk. This was exemplified by the blackout of 23rd January 2023. Wind power cannot be balanced by the inflexible coal and nuclear power plants in the south. When the AC/DC Corridors reach their stability-constrained Transfer Capacity limits, wind power cannot be balanced from Regulating Reserves. Only KE's 900 MW CCGT (Bin Qasim 3) with a ramp rate of 36 MW/min fulfils the criteria for frequency regulation in the south. However, manual frequency regulation is only possible for power plants dispatched by NPCC. In a meeting on 5th June 2023, the System Operator conveyed to KE its obligation to provide Primary Reserve in accordance with its share of system demand. In case KE is unable to provision adequate Operating Reserves from its own generation, the System Operator would provision KE's share and charge KE accordingly. A joint committee has been created to work out the details.

47. KE is presently discussing a wheeling arrangement for 600 MW from Jamshoro Coal power plant (J-CPP) Unit-1. In an informal meeting between KE, PPIB and the System Operator in NPCC on 7th June 2023, the System Operator explained that as J-CPP is connected to the national grid at 500kV, the power plant would be under the control of the System Operator. The power plant will likely always be running (when available) due to its critical location in the AC Corridor which provides power oscillation damping (POD) and improves transient stability. However, as per OC 5.4, the System Operator will ensure sufficient Primary and Secondary Reserve is provided from this power plant. Therefore, for a wheeling agreement of 600 MW at 500kV Kanupp-Karachi-Interchange (KKI), an average dispatch of 450 MW with 50 MW Primary Reserve and 100 MW Secondary Reserve may be considered for pricing purposes, whereas the over/under from Operating Reserves be proportionally allocated to CPPA-G/KE consumers as Ancillary Services. The remaining 150 MW "firm capacity" may be purchased at the basket price.