CHAPTER - 7

Grid Management

Electricity is produced at lower voltages (10000 volts to 25000 volts *i.e.* 10 kV to 25 kV) at generating stations and is stepped up to higher voltages[62] (220,000 volts to 765,000 volts *i.e* 220 kV to 765 kV) for transportation in bulk over long distances through transmission lines. Transmission lines are interconnected at switching stations and sub stations to form a network called the power 'Grid'.

7.1 Organisation of Power Grid

Power Grid or National Grid in the country is divided into five regional Grids namely Northern, Western, Eastern, North Eastern and Southern Grids. While first four Grids operated in synchronised[63] manner since August 2006, the Southern Grid has also been synchronously connected to the rest of the Grid through commissioning of single circuit of Raichur-Sholapur 765 kV line on 31 December 2013. The Western, Eastern and North Eastern Grids are together called the 'Central' Grid. The Northern and Southern Grids were subsequent addition in August 2006 and December 2013 respectively to the Central Grid. An overview of the components of National Grid is given in ***Annexure 7.1***. Operation of National Grid is a coordinated activity among various interfaces/agencies with MOP at the apex policy level at the Centre and PGCIL/ POSOCO through Load Despatch Centers (LDCs) at the operational level of the hierarchy (Block diagram given in ***Annexure 7.2***).

7.2 Grid Management

Electricity flows at close to the speed of light (2,97,600 kms per second) and must ideally be used, the instant it is produced. Electricity flows freely along all available paths from generators to the loads in accordance with the laws of Physics - dividing among all connected flow paths in the network, in inverse proportion to the resistance to such flow. Power flow in the Grid is managed through a process called 'Load Despatch', which involves balancing the load[64] and generation through a 'Scheduling' mechanism. Under this mechanism, power stations and distribution utilities inform their intended quantum of generation and drawal respectively for the next day to LDCs of their control area[65]. LDCs match the generation and drawal of all utilities in their control area with reference to the power transfer capability[66] and

[62] ***Operating transmission lines at high voltages reduces transmission losses due to heating and allows power to be shipped economically over long distances. Further it is economical to transport electricity than transport fuel for generating power.***

[63] ***Synchronization is the process of matching the speed and frequency of a generator or other source of electricity generation to a running network.***

[64] ***Load – The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumers.***

[65] ***An electrical system bounded by interconnections (tie-lines), metering and telemetry, where it controls its generation and / or load to maintain its interchange schedule with other control areas whenever required to do so and contribute to frequency regulation of the synchonously operating system. There are 150 control areas in the country.***

[66] ***Transfer capability refers to the amount of electric power that can be passed through a transmission network from one place to another having regard to reliability considerations.***

prepare the schedule each day, for the next day. For scheduling, a day is divided into 96 time blocks, each of 15 minutes duration and revisions are carried out in the schedule in real time depending on network conditions and feedback from the utilities. Thus, the 'Schedule' is a program drawn for the generating stations and distribution utilities. However, when power actually flows through the Grid, it may differ from the Schedule due to various reasons such as variation in energy supplied by the generating stations, variation in load from the forecast values, frequency and voltage fluctuations in the Grid, *etc.* Such variations in flows are called 'Unscheduled Interchange' or UI. LDCs, organized in hierarchical form (flow chart given in ***Annexure 7.3***) for smooth functioning of the Grid, monitor the power flows within their control areas through power system visualization tools and give necessary instructions to utilities through telephone calls and fax messages. Control of power flow across the Grid under normal operating conditions is achieved through physical action by utilities *i.e.* increase/decrease in generation by generating stations and connection/disconnection of feeders by distribution utilities as well as switching operations such as taking in/out a line. As these actions take some time, emergencies are handled by automatic actions through 'Special Protection Systems' which would instantaneously trip identified loads whenever a specific contingency occurs.

7.3 Classification of Grid Disturbances

A Grid Disturbance (GD) is a state of the power system under which a set of generating units/transmission elements trip in an abrupt and unplanned manner affecting power supply in a large area and/or causing the system parameters to deviate from normal values in a wider range. CEA is mandated with the responsibility of prescribing Grid Standards. As per CEA's Grid Standards, GDs are classified on a scale of one to five[67] depending on the severity of the antecedent generation or load lost. There were 816 instances of GD between April 2007 and September 2013. Analysis of region-wise and year-wise break-up of GDs for the period revealed that GDs of higher category (GD-3 and above) occurred on 69 occasions (8.46 *per cent* of total 816 instances). Number of GDs showed a mixed trend i.e. increase in numbers from 2008-09 (83 GDs) to 2009-10 (124 GDs); marginal decrease in 2010-11 (112 GDs); increase in 2011-12 (144 GDs) and decrease in 2012-13 (127 GDs). However, during 2013-14, up to September 2013 itself, number of GDs increased sharply to 176 as against 127 during 2012-13. WR had no higher category GDs and had only GD-1 disturbances. ER had the highest number of GDs (276 including 34 ungraded[68] GDs), followed by NR (233). Highest number (59) of GD-3 to GD-5 categories of GDs occurred in NER, out of which 19 were of GD-5 category.

Examination in audit revealed that the classification format of grid disturbances had a further scope for improvement as detailed below:

[67] ***Category GD-1 – When less than 10 per cent of the antecedent generation or load in a regional Grid is lost;***
GD–2-When 10 per cent to less than 20 per cent of the antecedent generation or load in a regional Grid is lost;
GD–3-When 20 per cent to less than 30 per cent of the antecedent generation or load in a regional Grid is lost;
GD–4-When 30 per cent to less than 40 per cent of the antecedent generation or load in a regional Grid is lost;
GD–5-When 40 per cent or more of the antecedent generation or load in a regional Grid is lost.

[68] ***GDs prior to notification of Central Electricity Authority (Grid Standards) Regulations 2010 were not graded.***

(a) There was no system/requirement to capture 'near-miss[69]' situations, though early warning of a major GD could be a near-miss before that[70].

(b) Grid standards did not capture seriousness in cases where load is lost in more than one region or cases where a region gets isolated from inter-connected regions indicating failure of synchronisation.

(c) Reporting framework did not mandate estimation of energy not served due to GD and revenue loss to users of the Grid.

PGCIL appreciated (March 2013) the audit observations and stated that these would be referred to CEA.

In the Exit Conference held on 15 April 2014, CEA agreed to consider the audit suggestion.

7.4 Major Grid Disturbances of 30 and 31 July 2012

There was a major GD in Northern Region at 0233 hours on 30 July 2012 leading to disturbance of the Northern Grid. Subsequently, there was another GD at 1300 hours on 31 July 2012 resulting in disturbance of Northern, Eastern and North-Eastern regional Grids[71]. Estimated population of 30 crore in eight States and one Union Territory[72] and estimated population of 60 crore in 21 States and one Union Territory[73] were affected respectively. The total load affected was 36000 MW on 30 July 2012 and 48000 MW on 31 July 2012.

CERC, in exercise of its power to regulate inter-State transmission of electricity under Section 79 (1) (C) of the Electricity Act, 2003, in its *suo-moto* order dated 1 August 2012 directed CEO of POSOCO and CMD of PGCIL, to investigate these Grid disturbances and submit a report within a week from the date of issue of its order. POSOCO/PGCIL submitted their report to CERC on 9 August 2012. CERC conducted four hearings on this report with the last hearing on 23 April 2013. CERC Order on the GD was issued on 22 February 2014 wherein violations of CERC Regulations by various entities were identified and action was proposed against them.

Besides, in order to investigate the reasons for the above two GDs and to suggest remedial measures, MOP also constituted (3 August 2012) a four member Enquiry Committee. The Committee in its report (GOI Report) dated 16 August 2012 opined that no single factor was responsible for the disturbances. The Committee attributed the disturbances to weak inter-regional corridors due to multiple outages, high loading on 400 kV Bina - Gwalior –Agra link

[69] *'Near miss' may be considered as an event that signals a system weakness that, if not remedied, could lead to significant consequences in the future.*

[70] *The major GD of 30 and 31 July 2012 were preceded by a near-miss situation on 29 July 2012.*

[71] *As per CEA's Grid Standards, the disturbance on 30 July 2012 falls under category GD-5 (GD 5 pertains to those disturbances when 40 per cent or more of the antecedent generation or load in a regional Grid is lost). On 31 July 2012 the disturbances were of GD 5 in three regions viz. NR, ER and NER and GD 1 in WR.*

[72] *Delhi, UP, Haryana, Rajasthan, Himachal Pradesh, Punjab, J & K, Uttaranchal and Chandigarh.*

[73] *Delhi, UP, Haryana, Rajasthan, Himachal Pradesh, Punjab, J & K, Uttarakhand, Sikkim, Assam, Tripura, Mizoram, Manipur, Arunachal Pradesh, Nagaland, Meghalaya, Bihar, Jharkhand, West Bengal, Orissa and parts of Madhya Pradesh and Union Territory of Chandigarh.*

and subsequent loss of the Bina-Gwalior link and inadequate response by State Load Despatch Centres (SLDCs) to RLDCs' instructions to reduce over drawal by power utilities of NR and under drawal/excess generation by utilities of WR.

Examination in audit of occurrence and management of GDs of 30 and 31 July 2012 with reference to above two reports, relevant records of proceedings and order of CERC[74] and the report (April 2004) of the US-Canada Power system Outage Task Force on the causes and recommendations of the US-Canada blackout of August 2003 revealed the following:

7.4.1 Deficiencies in planning shutdown of trunk line

POSOCO/PGCIL's report to CERC stated that transmission links between WR and NR got depleted progressively starting with planned outage on the high capacity Bina-Gwalior-Agra link. Power demand scenario of NR *vis-à-vis* availability of transmission links from WR to NR indicated that:

- Power consumption in NR generally increased during June-August every year during 2007-12 **(**Graph in ***Annexure 7.4)*** mainly due to 'weather beating' and agricultural loads. However, demand in WR remained lower during this period. This led to increased power flow from Western region towards Northern region during this period.
- Nine lines with a total transfer capability (TTC) of 2400 MW were available for flow of power from WR to NR. 72 *per cent* of flow ***(Annexure 7.7*)** during 2011-12 was through 400 kV Gwalior-Agra link (double circuit), which showed that this was the trunk line between WR-NR[75].
- Actual power flow through WR-NR corridor in July 2011 was 2291 MW which exceeded TTC of 1900 MW available at that time, underscoring the WR-NR transmission constraints in July. Existence of congestion in this corridor was further evidenced by the fact that RLDCs/NLDC levied congestion charges[76] on two occasions for the WR-NR corridor in July 2011.

PGCIL sought (e-mail/fax dated 23, 25 and 26 July 2012) shutdown of the Bina-Gwalior-Agra link from POSOCO for upgrading this line from 400 kV to 765 kV. Despite being aware of the criticality of this line for importing power to NR in peak season, the shutdown was allowed by NLDC from 26 to 29 July 2012 after reducing TTC of WR-NR from 2400 MW to 2000 MW[77].

The procedure laid down in IEGC for transmission outage envisaged a three stage outage planning process. In the first stage, annual outage plan is to be finalized by Regional Power

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[74] ***As displayed on website of CERC.***

[75] ***Bina-Gwalior link (double circuit) is the feeder link in WR for the Gwalior-Agra inter-regional link.***

[76] ***CERC Regulations on 'Measures to relieve congestion in real time' permit RLDCs/NLDC to levy congestion charges over and above energy charges if demand for power exceeds TTC.***

[77] ***Shutdown of Agra-Gwalior I line was allowed from 0800 hours to 1900 hours of 26 July 2012 for preparatory work. For Bina-Gwalior II upgradation, shutdown was allowed from 1000 hours of 27 July 2012 to 1800 hours of 29 July 2012; for Agra-Gwalior II, shutdown was allowed from 1000 hours of 28 July 2012 to 1800 hours of 29 July 2012.***

Committee (RPC) in coordination[78] with all parties concerned and in consultation with RLDC/NLDC. In the second stage, monthly review of transmission outage planning is required to be carried out at RPC level through the Operation Coordination sub-committee (OCC) of RPC. In the third stage, any outage approved by RPC is actually availed only after RLDCs permit the same depending on system conditions. Further, outage of inter-regional lines and all outages necessitating reduction in TTC and/or curtailment of transactions are availed only after concurrence of NLDC, which conducts system studies to identify precautions required to be taken for the same.

In the subject shut-down of July 2012, the first two stages were not followed and PGCIL's request was directly handled by Northern Regional Load Despatch Centre (NRLDC) and NLDC. NLDC reduced TTC from 2400 MW to 2000 MW to accommodate the shutdown in high demand period at a time when the users needed it the most, which was not in line with its role to ensure optimum utilization of power resources, as stipulated in Para 1.2.2 of 'Operating Procedures for National Grid'. Thus the shutdown was sought and availed at short notice without timely notice to the constituents, which was against the principle of advance planning envisaged under IEGC through a three stage coordinated process. Moreover, reduction of TTC due to the shut down was uploaded on NLDC web-site at 1000 hours on 26 July 2012 though the actual shut down started at 0825 hours on 26 July 2012.

MOP stated (March 2014) that the shut down became urgent in view of large power exchange requirements of NR through NR-WR interregional links and was planned for commissioning ahead of the Sasan UMPP whose anticipated completion schedule was December 2012; as such all civil and electrical works of line and sub-station were expeditiously completed and up-gradation work was planned for commissioning in July 2012; through various forums and meetings of the RPCs, beneficiaries are made aware of all projects under various stages of execution which is suffice to say that the beneficiaries were kept updated about this shut down also. MOP, however, assured that after the GDs, there has been improvement in outage planning at RPC level and the outage plan is discussed a day in advance of the OCC meeting.

The reply needs to be viewed against the following facts:

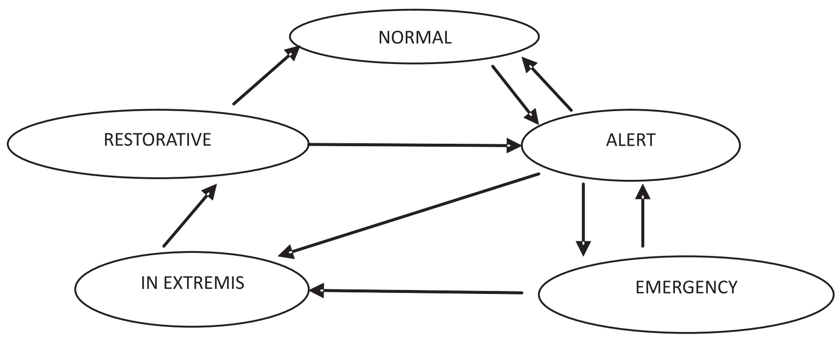
Reply does not address why up-gradation work of the line was not scheduled during lean season; further, the work for up-gradation which was intended to increase the transfer capability was ultimately completed in March 2013 and NLDC allowed higher TTC of 5700 MW in May 2013; however, the increased TTC of 5700 MW was rolled back in October 2013 due to reliability issues encountered in the WR-NR corridor after upgradation. Moreover, knowledge of projects under various stages of execution to constituents cannot be construed as information on outage planning of a crucial transmission element; in this case NRLDC and NLDC not only did not insist on RPC approval i.e. first and second stages of outage planning

[78] ***The advantage of such coordination is that the users of the network are aware of transfer capability that would be affected by the shut down and can seek deferment of shut downs if it affects their requirements and the RPC can take a considered decision.***

but also consciously approved a long outage of an inter-regional trunk line during peak season; presence of the antecedent loading upto 2900 MW which was more than the ATC of 2200 MW on the WR-NR corridor on 25 July 2012 (prior to the outage) gave an indication of what was in store if an outage was allowed on the trunk line of the corridor; it is seen that the first stage of the outage planning process *viz.* annual outage plan has not yet been initiated.

7.4.2 Handling of the disturbance by System Operators at NLDC/RLDCs

In system operator's parlance, a power system can be in any of the five states[79] (as shown below in diagram) and can traverse to any of the states as per the arrows indicated.



(States of Power System[80])

The system operators have their best chance of control in the 'Normal' and 'Alert' states though damage control methods are available for each state[81]. During the Grid disturbaces on 30 and 31 July 2012 also, the system went through these states but RLDCs/NLDC allowed the system to deteriorate to the 'in extremis' (uncontrollable cascade) state as explained below:

(a) Deficiency in declaring TTC and scheduling transfer of power

TTC[82] for inter-regional corridors is declared by NLDC on its web site, based on which RLDCs 'schedule' power. Northern RLDC (NRLDC) was thus expected to ensure that the quantum of power scheduled to be despatched to NR was not in excess of the Available Transfer Capability (ATC)[83] declared by NLDC. While assessing TTC, a principle called 'N-1 criterion' is followed for maintaining reliability which ensures that the system remains in secure condition

[79] ***In the 'normal' state, all system variables are within the normal range and no equipment is being overloaded. The 'Alert' stage denotes onset of instability, the 'emergency' stage denotes abnormal but controllable phase and the 'in extremis' stage refers to the uncontrollable cascade phase. The 'restorative' state represents a condition in which control action is being taken to reconnect all the facilities and to restore system load.***

[80] ***Source: As provided by POSOCO.***

[81] ***'Alert' - Generation re-despatch; 'Emergency' - fault clearing, excitation control, fast valving, generation tripping, generation runback, HVDC modulation and load shedding; 'In extremis' - load shedding and controlled separation.***

[82] ***Total Transfer Capability of a transmission network means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency. Here credible contingency means the likely-to-happen contingency, which would affect the Total Transfer Capability of the inter-control area transmission system.***

[83] ***Available Transfer capability (ATC) is equal to TTC minus transmission reliability margin fixed corridor wise by NLDC to ensure that the interconnected network is secure under a reasonable range of uncertainties in system conditions.***

even after loss of the most important generator or transmission facility (single contingency)[84]. CERC regulations [85] provided that NLDC might revise TTC on day-ahead basis depending upon system conditions.

While permitting shutdown of Bina-Gwalior-Agra line-II, NLDC had reduced TTC of WR-NR from 2400 MW to 2000 MW from 27 to 29 July 2012 (1900 Hrs) which stood restored on 29 July (1900 Hrs) to 2400 MW. NLDC, however, did not consider the need for restricting TTC of WR-NR to 2000 MW for 30 July 2012 on 29 July 2012 itself, though contingencies began to pile up, as explained below:

- While assessing the transfer capability for the WR-NR corridor as 2000 MW on 26 July 2012, the worst credible contingency considered was outage of Gwalior-Agra line I, the most heavily loaded line in the WR-NR corridor. All other lines were assumed to be available. However, after the beginning of shut down on 27 July 2012, three[86] of the remaining seven lines (excluding HVDC) tripped and a 'near-miss' situation happened at 1510 hours on 29 July2012**,** indicating onset of instability and the need to review TTC.
- NLDC did not revise TTC (from 2400 MW to 2000 MW) though the line under shut down (Bina-Gwalior-Agra- line II) was not returned to service[87]. Consequently, NRLDC allowed import of power ranging between 1941 MW and 2139 MW in 10 time blocks from 0000 hours to 0230 hours on 30 July 2012, against actual ATC of 1800 MW.

Similar inadequacies in declaring TTC of WR-NR corridor by NLDC after the Grid disturbance at 0233 hrs on 30 July 2012 were also observed. NLDC's assessment (1100 hours on 30 July 2012) of TTC of WR-NR as 2000 MW (ATC-1800 MW) for 30 and 31 July 2012 based on availability of all lines (except the under shutdown line of Agra-Gwalior-II and Agra-Gwalior-I Line on N-1 criterion), was on the higher side[88] as two more lines (*i.e.*Badod-Kota and Zerda-Kankroli) were also not available at that time. Accordingly, overloading of WR-NR links persisted on 31 July 2012 also and ultimately led to the second Grid disturbance at 1300 hours on 31 July 2012 when actual load of WR-NR corridor reached 1891 MW.

Further, NRLDC scheduled 2442 MW to 2629 MW of power through WR- NR corridor on 30 July 2012 from 0000 hrs to 0230 hrs prior to GD as against the already higher declared TTC of 2400 MW (ATC of 2200 MW). Thus, even the schedule was higher by 642 MW to 829 MW when compared with the ATC of 1800 MW fixed during planned shutdown of lines (26 to 29 July 2012).

[84] ***Single contingency means the worst single outage event of transmission line, generator, transformer, or substation bus bar.***

[85] ***CERC (Measures to relieve congestion in real time operation) Regulations, 2009***

[86] ***(i) 400 kV Zerda-Kankroli, (ii) 200 kV Badod-Morak and (iii) 200 kV Badod-Kota***

[87] ***The probability of extension of shut down was very high in this case because against three days shut down requested by PGCIL for up gradation work at Gwalior end, two days shut down was allowed.***

[88] ***As per the basis used by NLDC for declaring TTC, effect of the outage of Badod-Kota and Zerda-Kankroli links on TTC would have been to the extent of 200 MW reducing the ATC to 1600 MW. e.g. while declaring TTC for 15.9.2012 to 25.9.2012, TTC was enhanced by 100 MW due to restoration of 400 kV Zerda-Kankroli line. Similarly, while declaring TTC for 16.1.2013 to 17.1.2013, TTC was reduced by 100 MW due to shutdown of 220 kV Kota-Badod line.***

Thus, there were weaknesses in due diligence by NLDC and RLDCs in declaring TTC/ATC and scheduling of power across WR-NR corridor on 29 and 30 July 2012 which contributed to GD on 30 and 31 July 2012.

MOP stated (March 2014) that TTC/ATC did not matter for reliability (as per US/Canada Blackout Report) and added that TTC reduction involved detailed simulation studies which would have taken at least two hours, curtailing STOA would have taken another 2 hours and thereafter physical action of restricting over drawal/ under drawal would have taken further time. PGCIL argued that it resorted to the last step as it constituted affirmative physical action. Regarding higher scheduling of power, MOP stated that the operators faced dilemma in such cases; if the operator did not curtail the transactions beyond the planned outage hours and if the transmission system was not restored, there could be a compromise on grid security and the operator would get the blame. If he curtailed the transactions for the entire day and if the transmission system was back, the market players would counter the system operator; either way, the system operator function was tight roped.

The reply needs to be viewed against the following facts:

(i) Power flows through a corridor may be scheduled and unscheduled. While scheduled power flows are planned and regulated by RLDCs on 'day ahead basis' depending on TTC of the corridor, unscheduled power flows happen in real time and need to be controlled through coordinated and physical action by power utilities. Unlike in the USA, where TTC was arrived at a week before, (as mentioned in the USA/Canada blackout Report), in the Indian context, it is on a day ahead basis. Therefore, TTC has relevance in India so far as regulating scheduled power flows is concerned.

(ii) Actual power flow data for 0000 hrs to 0230 hrs on 30 July 2012 just prior to GD at 0233 hrs on 30 July 2012 revealed that overloading on WR-NR corridor beyond 2000 MW (TTC at which the WR-NR corridor was operating during 26 to 29 July 2012 when the Agra-Bina Gwalior-II line was under planned shutdown) was 26 MW to 218 MW[89] indicating that it was possible to relieve overloading through proper scheduling of power within TTC of 2000 MW. Even with Bina-Gwalior-Agra-II line remaining unavailable till 8 August 2012, any further Grid disturbance was averted by reducing TTC to 1250 MW.

(iii) POSOCO clarified that in real time operation, the system operator had little control as actions were generally automatic through relays and System Protection Schemes (SPS). Therefore, day ahead planning called for more diligence, which was not observed in this case.

(iv) The argument regarding operator's dilemma did not stand to reason because in terms of the 'Procedure for scheduling of collective transactions' approved by CERC, the

[89] ***Excluding loading on Mundra- Mohindergarh line for which TTC and scheduling is done separately.***

timeline for scheduling collective transactions did not end at 1300 hours. NLDC could have revisited the same till 1800 hours (i.e. by the time the status of Bina-Gwalior-Agra line II not coming back to service on 29 July 2012, was clear).

(b) WRLDC's role in the grid disturbance

As per report of POSOCO to CERC, the main strategy to control the overloading of WR-NR lines was to back down generation in WR, reduce under-drawal by WR utilities and reduce over drawal by NR utilities. These three activities were required to be carried out simultaneously for the desired result. Voice recordings of conversations between the control room staff of RLDCs and messages issued by them provide the record of steps taken in implementing the strategy. Examination of the voice recording revealed that WRLDC was unwilling to order generators to back down and suggested that NLDC should try to reduce over drawal by NR. (Excerpts from NLDC control room telephonic conversations in **Annexure 7.5**)

WRLDC did not instruct the State power utilities (SPUs) to stop under-drawal which was as high as 50 *per cent* of their scheduled drawal till 2137 hours on 29 July 2012. Thereafter, till 0010 hours of 30 July 2012, the messages did not mention specific action required on the part of SPUs. Generating stations including over-injecting ones were not asked to back down except Sipat unit of NTPC which was injecting 660 MW of infirm power (*i.e.* power generated by a power station prior to its date of commercial operation). Another Generating Station in the private sector *viz*. Coastal Gujarat Power Limited, Mundra having 800 MW capacity was injecting infirm power into the Grid but was not asked to back down. Finally, at 0021 hours of 30 July 2012, WRLDC endorsed a copy of NLDC 'fax' asking the WR States to reduce under drawal, which was the first clear message to SPUs about the action required on their part. Further, WRLDC did not direct Indira Sagar Hydro Power Plant[90] to reduce generation, though specifically instructed by NLDC, in the same message. Thus, GD could not be averted as WRLDC neither ordered generation back down nor issued proper instructions to SPUs in WR to reduce under drawal.

MOP stated (March 2014) that under drawal could be controlled through different methods such as removing load restrictions on consumers so that more load could be served within the State, reducing State's own Generation or reducing State's requisition from central sector plants or IPPs coming under RLDC's jurisdiction. SLDCs were best placed to take a holistic view else it would lead to frequent disputes between the State utilities and generating stations.

The argument that instructing generation back down would have invited commercial disputes is not convincing as IEGC has provisions {Clause 6.5 (27)} empowering RLDCs to order generation back down to protect Grid security. Further, WRLDC did instruct tripping of hydro power station of MPSEB[91] at 0257 hours of 30 July 2012, *i.e.* after the GD.

[90] ***Hydro power plants had the advantage of abrupt tripping unlike thermal generators which are gradually backed down.***
[91] ***Madhya Pradesh State Electricity Board***

(c) Hierarchical differences

NLDC was responsible for monitoring inter-regional lines and though NLDC was at the apex level of LDCs, its control room team was manned by junior staff as compared to those manning RLDCs. Review of voice recordings of telephonic conversations among NLDC and RLDCs revealed that NRLDC and ERLDC had inkling about the impending collapse and ERLDC alerted NLDC about the need to issue firm instructions to WRLDC which was not cooperating in the exercise of relieving loading on WR-NR corridor. However, NLDC operator was not able to assertively convey instructions to his counterpart in WRLDC and there was hesitation in the manner in which the serious subject of under drawal was broached/handled by NLDC operator, with WRLDC. (Excerpts from NLDC control room telephonic conversations in **Annexure 7.5**)

MOP stated (March 2014) that taking suggestions of Audit in a positive manner, POSOCO had already further strengthened posting of staff in NLDC Control Room.

(d) Inadequate off-line simulation study

Off-line simulation studies[92] are undertaken after major GDs to evaluate various alternatives that could have helped in averting the disturbance. One of the sub-groups of the GOI enquiry committee constituted to investigate GDs was assigned "Analysis of Grid disturbance on 30 and 31 July 2012 and simulation of the event". The sub-group stated that for specific answers to the disturbance of the Grids, a detailed load flow and transient stability simulation of the NR, ER- NER and WR Grids was required. The required study was not undertaken by the Task Force which was constituted by MOP in December 2012 for power system analysis.

MOP stated (March 2014) that POSOCO has since conducted the detailed offline simulation study and prepared a Report. MOP agreed that simulation as part of the Enquiry Committee findings would have been a more transparent and credible way rather than any in-house study by one agency considering the significance of assumptions involved in any simulation study.

7.4.3 Role of other agencies which aggravated the disturbance

Ensuring integrated operation of the Grid is a collective responsibility of various agencies. There was scope and need for clearly delineating the responsibilities of other agencies involved in Grid operation, as discussed below:-

(a) Heavy Underdrawal/Overdrawal by State power utilities

As per the hierarchical system in which LDCs operate, the LDCs at the state level are required to comply with the instructions of the respective RLDCs. While RLDCs give verbal/ written instructions, physical action by way of reducing load can be achieved only if the SLDCs,

[92] ***Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer 'what-if' questions to determine whether the system was in a safe operating state at that time. In the offline simulation study, the sequence of events as they occurred during the Grid disturbance is simulated to corroborate the findings of analysis done about the event.***

in turn, go for manual load shedding *i.e*. switching off power supply to areas depending on the quantum of load shedding required, category of consumer *etc*. RLDCs issued fax messages and made phone calls to SLDCs during the night of 29 July 2012 (two messages were also issued on 31 July 2012) to further instruct NR utilities to reduce over drawal and WR utilities to reduce under drawal. Despite this, five states[93] in NR and seven States/UTs[94] in WR did not comply with RLDCs' instructions and resorted to over drawal and under drawal respectively, as shown in ***Annexure 7.6***, which further contributed to Grid disturbance on 30 and 31 July 2012.

PGCIL confirmed (March 2013) the above position.

(b) Non-implementation of Special Protection Scheme

NRLDC moved a proposal (August 2010) to Northern Regional Power Committee (NRPC) for implementation of a Special Protection Scheme (SPS) to handle contingency arising due to sudden interruption of import by NR from WR through 400 kV Agra- Gwalior line. The proposal indicated that tripping of Bina-Gwalior circuits (in Agra-Gwalior-Bina line) resulted in rush of power flow through other interconnections of NR with WR and ER leading to overloading of networks with a potential to cause cascade tripping in large part of Grid. SPS envisaged shedding of loads in NR to be achieved within 500 milliseconds in such a contingency. This particular contingency had actually occurred thrice *i.e*. 28 November 2009, 7 December 2009 and 1 July 2010. NRPC approved (November 2010) the proposal and directed that PGCIL should implement it on priority. However, the target dates for implementation of the SPS were postponed by NRPC with the result that PGCIL did not implement SPS until after two GDs of 30 and 31 July 2012. SPS was partly implemented by PGCIL in August 2012.

MOP stated (March 2014) that generation back down in WR was to be identified and finalised by NRPC in coordination with Western Region Power Committee (WRPC); however, locations of generation back down were not identified; locations of load shedding were also altered many times by state utilities, last in the series was 24 July 2012. MOP, added that NRPC intimated, locations for generation back down in WR on 15 July 2013 and SPS had since been implemented by PGCIL.

The fact remains that timely action on implementation of SPS would have acted as a protective mechanism to avert GDs on 30 and 31 July 2012.

7.4.4 Restoration procedure

'Power System Restoration Procedures' of NLDC recognised that a weaker system that had a well-tested plan for emergency procedures for restoration might be more reliable than a stronger system with no such plan. These procedures further indicated that in the event of a blackout, the initial moments were extremely precious and it required the right decision to be taken at first instance for speedy restoration of the system. Though both the 'Bottoms up' and

[93] ***Uttar Pradesh, Punjab, Haryana, Rajasthan and Uttarakhand***
[94] ***Gujarat, Madhya Pradesh, Maharashtra, Chattisgarh, Goa, Dadra and Nagar Haveli and Daman and Diu.***

'Top down' approaches[95] were adopted while restoring power supply during GDs of 30 and 31 July 2012, 13.27 hours and 2.45 hours to 5 hours were taken for full restoration in different regions, on the two days respectively**.** Priority was given to restore traction (Transmission lines feeding Railway loads) which took one to eight hours on 30 July 2012 and 17 minutes to ten and half hours on 31 July 2012. In this connection, GOI enquiry found that after extending start-up power, most of the generating units took considerable time in 'lighting up[96].

Hydro Stations, which were required to play a significant role in restoration[97] as they had to produce power first, which was then extended through the lines to thermal stations, took time to black start[98]. There was a gap of one hour between the Grid disturbance (0233 hours on 30 July2012) and the time when the first Hydro Station black started (0340 hours on 30 July 2012) indicating loss of precious time. The other Hydro Stations took more time in black starting and took more than seven hours [99] to begin generation.

MOP stated (March 2014) that the restoration involved coordination among various groups (power stations, sub-stations, RLDC, NLDC etc.) and added that on 30 and 31 July 2012, the restoration time had been much less, as compared to other international grid disturbance incidences.

The reply is to be viewed against the fact that the restoration on 30 July 2012 turned out to be 'temporary' as the system collapsed in a bigger way the next day, on 31 July 2012. This would underline the need for putting in place clear benchmarks to assess the status of restoration of the system after a GD.

7.4.5 Long term and systemic issues relating to Grid Management

Examination in audit revealed that there was a scope for eliminating systemic inadequacies such as absence of warning system, weak inter regional connections and so on, in Grid management. These are discussed below:

(a) Warning System

Indian Electricity Grid Code (IEGC) has put in place a system of 'event reporting' as part of Grid management. However, an early warning mechanism by way of declaration of emergency status was not envisaged in IEGC. Report on the US-Canada blackout of August 2003, which offered a case study, had *inter alia*, mentioned that a transmission emergency existed when the system's line loadings and voltage/reactive levels were such that a single

[95] ***Bottoms up approach –Use 'Black start facility (Building the grid after a grid disturbance) available within the region among hydro, gas and some thermal power stations to start producing power, add loads step by step and build blocks of restored areas;***
Top down approach - Take power from other regions which remain connected to initiate restoration in the affected region.

[96] ***Lighting up is used in the context of coal fired generating units and refers to the starting up of the boilers using oil (could be either Light Diesel Oil or Low Sulphur Heavy Stock or Heavy furnace Oil) depending on the boiler design. Only after this process is complete, the steam turbine can be rolled and the generator synchronized to the main grid.***

[97] ***As they can begin generation almost immediately since no 'lighting up' of boiler was involved.***

[98] ***Building the grid after a grid disturbance***

[99] ***Chamera Unit II started at 1017 hours i.e. 0744 hours after the blackout at 0233 hours.***

contingency could threaten the reliability of the interconnection. The Report further stated that the North American Electrical Reliability Council (NERC) Operating Manual defined various types of emergency such as 'capacity emergency' and 'energy emergency'. There would appear to be a need to introduce similar provisions in the IEGC to deal with situations of GD with potential cascading effect.

MOP noted (March 2014) the observation for taking up the matter with appropriate regulatory authorities.

(b) Inter-connection of NR with neighbouring Regions

One of the indicators of strength of bonds between regions is the distribution of power flow among various links during real time operation. *Inter-se* distribution of power flow among inter-regional links indicated that power transmission to and from NR depended on two trunk lines *viz*. 400 kV Agra-Gwalior (for WR-NR) and 400 kV Muzaffarpur– Gorakhpur (for ER-NR). Regular heavy power flows during the last three years **(*Annexure 7.7*)** indicated high-risk of isolation of NR in the event of outage of these lines.

PGCIL went in for a planned shutdown of one of the circuits of the 400 kV Agra-Gwalior link. The power flows, however, could not be handled by other links which tripped/went on forced outage much before their loadable limits and the system eventually collapsed on 30 and 31 July 2012. There is thus, a need to strengthen the bonding of NR with the connecting regions which would ensure more dispersed power flow across existing links.

MOP stated (March 2014) that to address the issue many additional links have already been planned between NR and WR viz. Gwalior(WR) – Jaipur(NR) 765 kV 2x single circuit line, Champa (WR) – Kurukshetra (NR) $\pm$800 kV, 6000 MW HVDC bipole line, Jabalpur(WR)–Orai (NR) 765 kV D/c line which were under different stages of implementation.

MOP may consider advising PGCIL to expedite the commissioning of proposed linkages and review the adequacy thereof to ensure a reasonably dispersed power flow.

(c) *Regulatory tools to deal with congestion*

CERC (Measures to relieve congestion in real time operation) Regulations, 2009 define 'congestion' as a situation where the demand for transmission capacity exceeded ATC. NLDC/RLDCs have been empowered to levy congestion charge[100] to relieve congestion in real time for which CERC approved 'real time congestion management procedure' under clause(2) of Regulation No. 4 *ibid.* On 30 and 31 July 2012, NLDC/NRLDC did not kick-in congestion charges though the WR-NR and ER-NR corridors faced congestion. NLDC attributed this to limiting provisions in CERC Regulations. In this connection, GOI enquiry report had pointed out that there was no provision in regulations that restrained NLDC from applying congestion

[100] ***Congestion charge may be imposed on a regional entity or entities causing congestion and paid to any regional entity or entities relieving congestion. The rate of congestion charge is ₹5.45 per unit which was in the nature of a commercial deterrent in bringing down congestion.***

charges but detailed procedure on 'real time congestion management' did restrain NLDC from applying congestion charges. The GOI enquiry report added that the procedure was inconsistent with the regulations.

There was a scope for further improvement in levy of congestion charges proposed in 'Detailed Procedure for relieving congestion in real time operation' as discussed below:-

(i) NLDC proposed that congestion charges would be applied simultaneously on all entities in the upstream[101] and downstream[102] areas. The approved procedure indicated that at frequency below 50 Hz congestion charge would be levied for over drawal or under injection in the importing control area and at frequency above 50 Hz congestion charge would be levied for under drawal or over injection in the exporting control area.

(ii) As per NLDC's proposal, if congestion is caused by forced outage, open access transactions shall be curtailed first followed by revision of TTC. However, as per approved procedure, no congestion charge was to be applied in such cases.

Application of congestion charge differently for frequencies above and below 50 Hz could give an impression that congestion was a problem linked to frequency. This notion had an adverse impact in controlling congestion on 30 July 2012 as one of the SLDCs, (SLDC, Maharashtra), in response to the line loading message of WRLDC, stated that below 50 Hz overdrawing constituents were responsible (for congestion). The actual situation was that the underdrawal by WR utilities was causing congestion of the WR-NR corridor. The second condition mentioned above prevented RLDCs from levying congestion charge on 30 and 31 July 2012 as there were forced outages.

Apart from the above, clause 5.4.2 of IEGC enjoined upon States to resort to load shedding if the frequency fell below 49.5 Hz. However, problems arising from under drawal and their impact on line loadings needed to be addressed more adequately in IEGC. The focus of the provisions in IEGC was mainly to discourage overdrawal by beneficiaries. Amendments to address the problems arising out of under drawal were introduced in IEGC only after the GDs of 30 and 31 July 2012.

PGCIL stated (March 2013) that they had taken up procedural difficulties in levying congestion charges with CERC which had since amended (April 2013) the procedure accepting the earlier stand of NLDC. In the Exit Conference (April 2014) representative of CERC stated that necessary changes had been carried out in the regulations.

(d) Unscheduled Interchange of power flows

Financial settlement of energy exchanges across the Grid is carried out through a mechanism called Availability Based Tariff (ABT). ABT comprises three components: (a) capacity charge, towards reimbursement of the fixed cost of the plant, linked to the plant's

[101] ***Exporting region***
[102] ***Importing region***

declared capacity to supply MWs[103], (b) energy charge, to reimburse the fuel cost for scheduled generation, and (c) Unscheduled Interchange (UI)[104] charge, a payment for deviations from schedule, at a rate dependent on the system frequency. While 'Scheduled' power is supported by contracts between buyers and sellers, UI flows are settled subsequently by RLDCs which maintain the UI Accounts.

The UI mechanism was based on the philosophy that the 'Schedule' was meant to serve as operational and commercial datum and the parties were perpetually encouraged to deviate in the direction beneficial for the interconnection *i.e*. towards enhancing overall optimization and/or improving frequency. UI was, thus, meant to be a sort of 'Seesaw' to keep the frequency within range through commercial incentives and disincentives[105]. The broad frame work was that the over drawing Discoms and 'under injecting' generators compensated monetarily the under drawing Discoms and over injecting generators respectively. The UI mechanism found wide acceptance among the stakeholders in view of its various benefits[106] and the National Electricity Policy, 2005 stated that the ABT mechanism (UI was a component of ABT) has enabled a credible settlement mechanism for intra-day power transfers from licensees with surpluses to licensees experiencing deficits.

Analysis of power flows across major inter-regional corridors during 2009-10 to 2011-12 revealed that the quantum of UI formed a significant portion of the total flows and was even more than scheduled flows in some months, as can be seen from ***Annexure 7.8.*** However, congestion arose when the cumulative flows *i.e*. Scheduled and UI outstripped the TTC of the corridors **(**illustrated in **Annexure 7.9**).

Though UI mechanism had beneficial results on certain fronts such as frequency control, better utilisation of transmission and generation resources *etc*., there were areas which posed challenges in Grid management as discussed below:

(i) Need for due regard to N-1 principle

Power system operation is based on a principle called the N-1 criterion according to which, transfer capability is assessed considering outage of the most important element. Thus, while

[103] ***In case the average availability actually achieved over the year is higher than the specified norm for plant availability, the generating company gets a higher payment. In case the average availability achieved is lower, the payment is also lower. Hence the name 'Availability Based Tariff'.***

[104] ***UI in a time block is the difference between actual and scheduled generation or actual and scheduled drawal for a generator or a beneficiary respectively.***

[105] ***The fundamental parameter that measures the stability of the grid is its frequency which depends on the number of revolutions per minute (RPM) of the generators that are connected to the Grid. Frequency remains the same throughout an AC electrical system and if the frequency is 50 Hz, it means that all the generators connected to the grid are operating at the same speed. Closer the frequency is to 50 Hz, the better it is both for the power generating equipments at the power stations and the appliances at the consumer end. If persistent under frequency occurs it means that somewhere there is 'leaning on the grid' i.e. drawal of unscheduled electricity from the grid which depresses system frequency. The graded UI table is designed in such a way that in case of low frequency, the Discoms are encouraged to underdraw while the generators are encouraged to over inject. On the other hand, when the frequency is higher than the permitted range, it means that there is less demand for power or the tendency to detach from the grid. Under such conditions, the UI charges encourage the Discoms to overdraw and the generators to back down.***

[106] ***Grid operators – UI brought about frequency control and promoted grid stability; Discoms- Commercial incentives for underdrawals and the facility of overdrawing from the grid depending on the frequency; Generators- Commercial incentives for over-injection depending on frequency; Investors (Beneficiaries, CTU, GOI) – Optimum utilization of resources.***

preparing to schedule energy exchanges across the Grid, a reserve capability is maintained to take care of the worst single contingency in real time operation. Additional reserve by way of a reliability margin is also kept to handle any unforeseen contingencies/errors in assumptions, *etc*. However, both these reserves could get depleted depending on the quantum of UI flows and occurrence of contingencies during real time operation. For example, during GD on 30 and 31 July 2012, the worst single contingency actually happened (outage of Bina Gwalior-I line) and reliability margin of 200 MW for WR-NR proved inadequate to handle additional contingencies. With the depletion of all reserves, the corridor faced a 'cascade' of trippings. Thus, UI mechanism did not factor in the N-1 criterion which is fundamental to power system operation.

(ii) Commercial considerations by Discoms

It may be economical for a Discom to draw power through UI, even at penal slabs, rather than purchase power through organised sale channels like power exchanges or bilateral trade. This is because Unscheduled Interchange (UI) charges are levied at rates stipulated in CERC Regulations (rates notified in April 2010), while short term sale prices are market determined and vary according to demand-supply gap. In majority of the months during April 2011 to October 2012, the average UI rate was lower than the short term sale price for power sold through bilateral trades. Test check of two overdrawing States *viz.* Uttar Pradesh and Haryana, during April 2011 to September 2012, indicated that out of 14 months when overdrawal was made by these states, UI rates were less than bilateral trade rates in 11 and 10 months respectively.

Commercial considerations of Discoms to purchase power through UI instead of power exchanges/bilateral trades which are part of scheduled flows, may have the tendency to escalate congestion in the Grid. Therefore, there is a need for POSOCO to take up with CERC, the desirability of linking UI prices with exchange prices. It is also relevant to note, in this connection that, though as per CERC Regulations, UI rates were required to be notified by CERC every six months, the rates were not notified for more than two years, until September 2012, which was after the GD on 30 and 31 July 2012.

(iii) Demand-supply gap of States

Electricity being a concurrent subject under the Constitution of India, ensuring power supply involves combined efforts of the Central and State Governments. State Governments have their own generating stations and undertake efforts like capacity addition, bilateral procurement from surplus states, buying power from power exchanges *etc*, to meet the increasing demand for power. While States can avail entire power generated from the power plants owned by their respective SPUs, power generated by central sector power plants located in States is allocated as per fixed guidelines which stipulated as follows:-

- Up to 2010:

  (a) 15 *per cent* capacity was kept at the disposal of GOI

  (b) 10 *per cent was* allocated to the State in which the project was located (Home State)

  (c) 75 *per cent* of power was allocated to the States in the region including Home State

- From January 2011

  Modified guidelines, as below, for application in respect of thermal power plants of NTPC and Nuclear Power Corporation of India were approved by Cabinet in January 2011.

  (a) 15 *per cent* capacity is kept at the disposal of GOI

  (b) 50 *per cent* allocated to the State in which the project is located (Home State)

  (c) 35 *per cent* of power is allocated to other States in the region excluding Home State.

  Analysis of demand-supply data in NR during 2011-12 in audit revealed that:

- Demand-supply gap was not uniform among States. In eight States and one Union Territory in NR, demand supply deficit in Delhi, Haryana and Chandigarh was less than 100 MUs during the year while the same was significantly high ranging from 305 MUs to 9223 MUs in remaining six states. Normally a power deficient State might tend to overdraw from the Grid while a power surplus State might tend to under draw. This trend was seen in six out of eight States and one Union Territory of NR (***Annexure 7.10***). Delhi had consistently under drawn and earned UI revenue of ₹1261.44 crore during April 2011 to October 2012 while Uttar Pradesh had consistently overdrawn during 2011-12 and dues on account of UI had accumulated to ₹974.42 crore as on 31 March 2012 and further increased to ₹2529.71 crore as on 31 March 2013.

- It was possible for Discoms of power surplus States to seek a higher schedule of power and actually draw less power than the schedule in real time. Through under drawal of power as compared to the power scheduled for them, it was possible for power surplus States to earn UI revenue. As large inequalities in availability of power have the potential of increasing UI which may contribute to congestion in the Grid, it is necessary for MOP to address this issue during the process of allocation of power to States from central sector power plants.

- Over dues of UI payments aggregating ₹ 2570.86 crore as of March 2013 indicated that States were able to overdraw from the Grid without immediately paying for it. There is thus, a need for MOP to curb the practice through appropriate penal provisions[107].

(iv) Inter play between UI and congestion mitigation measures

UI mechanism is focussed on frequency based control whereas 'line loading' may or may not be dependent on frequency. There may be situations when the frequency is within the operating range but one or more critical elements of the transmission system may be overloaded. However, UI mechanism remunerates under drawing and over injecting SPUs for all frequencies within the prescribed frequency band. This may run counter to congestion mitigation measures being tried by RLDCs to bring down 'line loading'.

[107] ***CERC has levied (May 2006) a token penalty of ₹ one lakh on UPPCL for in-disciplined over drawal from the Grid.***

During the GD of 30 July 2012, the frequency was within the prescribed band. It was thus favourable for SPUs in WR to earn UI income through under drawals and over injection and they were reluctant to reduce under drawals or over injection as is evident from communication received (at 22.33 Hrs on 29 July 2012) from SLDC, Maharashtra. Such reduction could have relieved the heavy loading of WR-NR corridor. UI Regulations did not have provisions to suspend UI mechanism during times of congestion and emergency which may affect the efforts of RLDCs to ease congestion aggravated by under drawals.

WR Utilities {Generating Stations (Regional) and State Discoms} had earned UI income of ₹73.05 core during the four days from 27 July 2012 to 30 July 2012, though under drawal and over injection by WR utilities was causing congestion in the WR-NR corridor. It was possible for an SPU to earn UI income either by seeking a higher schedule than what was required or through load shedding and both the strategies were being adopted by Discoms in WR. Hence under drawal and over injection got rewarded in the UI mechanism even as it had the potential to aggravate congestion and threaten Grid security. This anomaly needs to be addressed.

POSOCO stated (June2013) that they had taken up the issue of restriction of UI volumes with CERC.

In the Exit Conference (April 2014) CERC representative stated that the new Regulations have been notified recently which limit UI irrespective of the frequency of the system and that time may be given to see their impact.

(e) Inadequacies in human resource management

RLDCs/NLDC operate a shift system while deploying personnel for manning the control rooms. Review of the procedures in this regard revealed the following:

➢ ***Long night shifts***

The duration of night shift is 11 hours 20 minutes as against six hours 40 minutes for morning and afternoon shifts. Long night shifts are likely to cause fatigue and loss of concentration among personnel. Duration of night shift needs to be reviewed *vis-à-vis* time duration of day shifts so as to reduce the possibility of errors due to fatigue.

➢ ***Capacity building of system operators***

Broad requirements of training/capacity building prescribed for system operators were 'three' level certification of system operators (basic, specialist and management level); renewal of certificate every three years and continuing professional development through various refresher courses and advanced level training courses. A comparison of the status of fulfilment of the requirements by the system operators employed in RLDCs/NLDC indicated that 58 *per cent* of the control room staff had not undergone the basic level training (Short term course of power system operators). Advanced level training was yet to be imparted to operators (March 2013). Non-executives were also deployed in the control rooms (nearly 50 *per cent* in shift groups) and no minimum requirement of certification was prescribed for them.

PGCIL appreciated (March 2013) the audit observations.

7.4.6 Impact of Grid disturbances on 30 and 31 July 2012

Grid disturbances cause economic loss to Generating Stations, Distribution Utilities, Trading agencies and end users such as households, industrial units, *etc*. who have to incur extra expenditure on alternative sources to produce power during the outage period. These also have an unquantifiable adverse impact on maintenance and delivery of essential services including medical treatment and emergencies. Neither GOI Enquiry Report of August 2012 nor PGCIL/POSOCO's report dated 9 August 2012 to CERC mentioned about these losses. In reply to an Audit query, POSOCO informed that energy not served *i.e*. energy that would have been served to consumers on a normal day of the same period, due to two GDs was 390 million units on 30 July 2012 and 366.80 million units (MUs) on 31 July 2012. This works out to around one third of total average energy produced in a day (average energy per day is 2400 MUs while the energy not served for the two days was 757 MUs).

Thus, a large part of the country had to go without electricity for hours due to GDs on 30 and 31 July 2012. As discussed in the preceding paragraphs, the situation was possible to have been avoided if

(i) PGCIL had carried out outage planning during lean season,

(ii) NLDC had reviewed TTC and contingency status timely and conveyed instructions to WRLDC assertively,

(iii) SLDCs had acted upon the instructions of RLDCs promptly to reduce over drawal/ under drawal/ over injection.

Systemic improvements by way of introduction of warning system to convey emergencies to constituents, strengthening of interregional corridors, effective regulatory tools to deal with congestion and UI mechanism would further improve Grid Management.

MOP stated (March 2014) that the high level Technical Enquiry Committee constituted by the Government of India after the GDs had already analyzed the incident in depth and came to the conclusion that no single factor was responsible for grid disturbances on 30th and 31st July 2012. Similarly, POSOCO and CTU's report to the CERC had also highlighted the systemic issues which needed serious attention. MOP was of the view that highlighting issues such as approval of 400 kV Bina-Gwalior-Agra outage during peak season, non-revision of TTC and lack of actions in real time by RLDCs/NLDC as the reasons for the grid disturbances would result in the larger issues getting lost.

MOP however assured that the observations by Audit had been taken note of and efforts were being made to continuously improve the system by all concerned.

The fact remains that the GDs were initiated by the outage of the Bina-Gwalior-Agra link during peak season which was planned without following the due procedure (Para 7.4.1). This was further compounded by non-revision of TTC and higher scheduling of power (para 7.4.2 (a)).

During discussion in the Exit Conference (April 2014), MOP accepted that the happenings leading to GDs of 30 and 31 July 2012 as brought out by Audit point to the need for bringing out systemic changes and a tighter control over TTC.

7.4.7 Remedial measures taken after GDs of July 2012

POSOCO and PGCIL have, however, taken remedial measures to improve grid operation after the two GDs of 30 and 31 July 2012,which included the following:

(i) Senior officials were deployed on control room duty.

(ii) Special Protection Scheme was implemented for the contingency of outage of Agra-Gwalior circuit.

(iii) Permissible frequency band was tightened from 49.5 – 50.2 Hz to 49.7– 50.2 Hz.

(iv) The procedure for congestion management was amended to give more operational freedom to RLDCs to handle congestion.

(v) An advanced version of software was procured to improve the quality of power system simulation studies.

Apart from the above, petitions filed by POSOCO in CERC to improve real time data availability (called 'telemetry') at RLDCs, amendments to Indian Electricity Grid Code, new deviation settlement mechanism, automatic demand management by SLDCs, *etc* were under various stages of consideration by CERC. These are expected to further improve Grid Management.