REPORT

OF

THE TASK FORCE

ON

POWER SYSTEM ANALYSIS UNDER CONTINGENCIES

AUGUST 2013
NEW DELHI

CONTENTS

ACKNOWLEDGEMENT

The Task Force acknowledges the contributions of the various officers of CTU, POSOCO, ABB & Tata Power who assisted the Task Force in its deliberations.

The Task Force would specifically like to acknowledge the assistance given by Shri S.R.Narasimhan, DGM, POSOCO and other officers of POSOCO & CTU, Shri B.S.Palki and Shri R.S.Moni, ABB in carrying out the relevant studies.

The Task Force would also like to acknowledge the assistance of CTU & Shri P.K.Pahwa, Member Secretary, NRPC for providing the logistics for conduct of the Meeting of the Task Force.

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EXECUTIVE SUMMARY

(1) As a follow up of one of the recommendations of Enquiry Committee headed by Chairman, CEA on grid disturbances that took place in Indian grid on 30th and 31st July 2012, Ministry of Power constituted a 'Task Force on Power System Analysis under Contingencies' in December 2012. The Terms of Reference of Task Force broadly cover analysis of the network behavior under normal conditions and contingencies, review of the philosophy of operation of protection relays, review of islanding schemes and technological options to improve the performance of the grid.

(2) The Task Force included representatives from the utilities, grid operators, academia & manufacturers. Shri A.K.Asthana, Advisor, Reliance Power Transmission (former Chief Engineer, CEA) and Shri. P.K.Pahwa, Member Secretary, NRPC were co-opted to assist the Task Force. The Task Force had seven meetings in which operational practices were reviewed and discussion held on various issues concerning safe and secure operation of grid. The Task Force also constituted two sub-committees – one for system studies for July-September 2013 conditions and one for examining philosophy of relay and protection coordination – and reports submitted by these sub-committees were discussed and analyzed in detail. The Task Force also had benefit of advice from industry experts who were invited to participate in deliberations on issues relating to new technologies and performance of operation of existing islanding schemes etc. Based on these exercises, the Task Force has arrived at specific recommendations on plan of action for operation of the grid in a secure manner.

(3) **CONTINGENCY AND STABILITY STUDIES :** Exercises such as analysis of grid conditions and factors affecting operation of grid and simulation of system conditions corresponding to critical operation conditions expected in forthcoming seasons should be done on a regular basis and suitable operation strategy worked out. Exercise for present grid conditions and forthcoming season e.g. peak load conditions of July-September 2013 have been done and the same are reported in Chapter-3 and Chapter-4 of this report, Similar exercises should be done on a regular basis and load dispatchers appraised of findings so that suitable operation strategy is worked and implemented. Load dispatchers at National, Regional and State level should also be equipped to carryout load flow, contingency and stability studies of real-time network taking data from SCADA system for assessing safe transmission capacity on a real-time basis for having a vivid picture of security impact of various contingency depletions under real time operating conditions and taking necessary actions towards ensuring grid security in best possible manner.

(4) **ISLANDING SCHEMES:** The Task Force has felt that having a very large number of islanding schemes may not be in interest of secure integrated operation of grid. It also observed that in the proposed islanding scheme for Delhi, opening of a large number of elements has been envisaged. For the island formation, all the elements connecting to rest of grid have to be opened simultaneously. Failure in simultaneous opening of interconnecting feeders can happen due to communication failure or mal operation. This may jeopardize successful formation of Delhi Island. Also, the rest of grid would lose all interconnecting lines along with islanding sub part and it would cause major depletion in an already distressed grid. If trigger occurs due to mal-operation, the islanding scheme itself would become a cause of grid disturbance. The Task Force felt that instead of planning large number of islanding schemes in an ad hoc manner, it would be better to evolve some guidelines based on which proposals for islanding schemes could be formulated. There is also a need to review the settings

of under frequency relays and also the quantum of load shedding to be done under various system operating conditions. Suggested guidelines as emerged from discussions held in the Task Force, are given in Chapter-5.

(5) **TRANSMISSION OPERATIONAL PLANNING CRITERIA :** The Task Force has felt that there is a need of having a Transmission Operational Planning Criteria different from Transmission Planning Criteria of CEA which forms basis for network expansion planning. While 'N-1' or 'N-1-1' may suffice for expansion planning, operational security may require 'N-x-1', "N-x-1-1' or 'N-x-2' or even higher particularly in view of outage of multiple elements. However, it needs to be kept in view that restricting dispatches based on security criteria much higher than that adopted for planning would result in drastically curtailing power supplies in an already deficit scenario. As such, violation of higher security criteria has to be used as a trigger for alert, alarmed or emergency status. The issues require further deliberations to evolve optimal operational strategy.

(6) **FREQUENCY REGULATION :** It is seen that although there is improvement in average frequency, there is not much improvement in narrowing down the frequency band. With increase in average frequency, increase in percentage of time frequency is above 50.2 HZ is also being observed. This is not a good indication. There is scope for improvement towards tighter frequency band of operation together with reduction in load curtailment with increased utilization of generation while maintaining better grid security. This requires better management of the schedules by all utilities by proper load management and ensuring stable frequency through Free Governor Mode of Operation of the generators. This will have to be complimented with improved day ahead and real time load forecast together with mechanism for secondary and tertiary control through maintaining of spinning reserves. Mechanism for settlement of

deviations would also require a change from frequency linked UI tariff regime to a system of settlement in kind and penalty for exceeding deviations from specified limits. The existing UI mechanism needs to be reviewed and conflicts removed so that it does not come in the way of governor mode of operation. Unless the FGMO and ancillary services are introduced along with tight frequency band and real-time balancing mechanism the stable frequency operation will be difficult to achieve.

(7) **INTEGRATION OF RENEWABLE ENERGY IN THE GRID:** Integration of renewable energy in the grid is one of the biggest thrust areas. The installed generation capacity of renewable generators is expected to grow manifold in the coming years. Considering the variability and infirmity of generation from renewable resources, there is a need to have strong interconnections together with stable grid frequency maintained close to the nominal operating frequency in a narrower band so that energy injection from renewable sources can be safely absorbed in the grid.

(8) **CONTROLLING HIGH VOLTAGES IN GRID DURING PERIODS OF LOW LINE LOADINGS:** One of the problems affecting the operation of the grid is high voltages in the grid during period of low line loadings. Under such conditions, even after exhausting management of all reactive power elements there is a need to open number of 400 kV lines to control the high voltages which results in reduced system reliability. The Central Transmission Utility (CTU) has planned installation of number of shunt reactors in the grid to control the over voltages. However, it is observed that even the generator buses face high voltages. Therefore, there is need to review the tap setting on all generator transformers and take advantage of the reactive capability of the generators and regulation of the excitation system so that the voltage profile of the grid is properly managed. It is also observed that generators shy away from providing full reactive support taking shelter under pretext of operating conditions

limiting their capabilities. In this context, there is a need to validate reactive capabilities of generators to arrive at realistically attainable values which should be used in planning and operation of grid. Additionally tariff incentives may need to be considered for facilitating operation of hydro generators in synchronous condenser mode. It is also necessary that schedules are issued so that the transmissions lines are loaded to their capability. Conservative approach in loading transmission lines would result in high voltages and opening of lines to control the overvoltage will result in depleting the transmission capability and under utilization available generation capacity.

(9) **LOW VOLTAGE PROBLEM :** Certain parts of the Northern grid specifically in Punjab, Western UP, Uttarakhand & J&K face severe low voltage problems especially in July to September in Punjab and during winter months in the hill states. There is need for installation of adequate shunt capacitors to address the issue of low power factor of incident loads. There is an urgent need to address this issue as otherwise there an apprehension of voltage instability. SVC schemes are under implementation which would address this issue to some extent. For further improvement in this area, application of STATCOM, which are state of art equipment for providing dynamic Var support for better voltage stability, should also be considered.

(10) **OPERATIONAL CRITICALITIES PREVAILING IN GRID REQUIRING ATTENTION OF LOAD DISPATCHER**

Analysis and Studies got carried out by the Task Force has emphasized need for higher attention of grid managers and load dispatcher to monitor and take appropriate real time actions to following operational constrains:

(10)-a **ER-SR and S1-S2 constraints :** Sustained high loadings on 400 kV D/C Vijaywada-Nellore line and on 400 kV Hosur-Salem cause ER-SR and S1-S2 constraints. These would get relieved on commissioning of new generating units in Tamil Nadu and southern Andhra Pradesh on addition of new lines in corridor. Addition of Vijayawada-Nellore-Thiruvalam-Kalivandapattu 400kV D/c line, under construction on priority by CTU, would relieve the constraints.

(10)-b **High loading of 400 kV Rourkela-Talcher D/C** is experienced during April to June when availability of hydro power in ER as well as in SR is low whereas the demand is high. To limit the loading on Rourkela-Talcher to its thermal limit (approx. 850 MW) on N-1 contingency of the other circuit, either line is not allowed to get loaded beyond 530 MW. Talcher – Rourkela 400 kV D/c (quad) which may have mitigated the problem, was awarded for implementation by private sector under competitive bidding route more than three years ago. However, work on the line has not yet started. Issues with implementation of this line need to be resolved at the earliest.

(10)-c **Evacuation Constraints from Nathpa Jhakri, Karcham Wangtoo and Baspa Hydro Projects :** Power evacuation from these projects is through 400 kV Jhakri-Nalagarh D/C, 400 kV Jhakri-Panchkula-Abdullapur D/C and 400 kV Karcham-Abdullapur D/C. During monsoon period when all these hydro plants generate their maximum, lines from Jhakri towards Nalagarh/Patiala (Punjab) get loaded to their full capacity. Shutdown on these evacuation lines should not be allowed during monsoon period and under emergency shutdown or forced outage, adequate backing down of generation at Nathpa Jhakri, Karcham Wangtoo, Baspa and also at AD Hydro and Malana HEPs should be done to ensure secure grid operation. Commissioning of Parbati(III)-Amritsar and Koldam-Ludhiana 400kV D/c lines and connection of additional load of at Panchkula 400/220kV substation would relieve Nathpa Jhakri – Patiala 400kV D/C line.

(10)-d **High Loading of 400 kV Purnea-Muzaffarpur** is experienced during the period of monsoon (July to September) when generation at Teesta, Tala & Chukha along with power from NER is transmitted towards NR. Due scheduling restrictions and close monitoring should be done to keep power flow on Purnea-Muzzaffarpur D/C line with in secure limits. Purnea-Biharsharif 400kV (quad) D/c being implemented under private sector and Kishangarh-Patna 400kV (quad) D/c being implemented by POWERGRID would mitigate the problem

(10)-e **Constraints due to wind generation in South TN:** Installed capacity of Wind Energy in Tamil Nadu is about 7000 MW with peak generation reaching about 3900 MW. Many 230 kV/110 kV lines and 400/230kV ICTs at Tirunelvelli get severely stressed during wind peak in Tirunelveli area. For this quantum of wind power, operational dispatch and load management alone is not adequate to mitigate the impact of its intermittence and variability on grid parameters. For facilitating further increase in wind power appropriate technical solution of this problem should be explored and implemented. Tamil Nadu has to implement 400kV network from that area to Chennai area. This needs to be completed on priority to relieve the congestion in the corridor.

(10)-f **High loading of 400 kV Farraka-Malda D/C** is experienced during the period from October to March, when NER draws power from ER due to low generation at Tala, Chukka and Teesta. Dispatches are regulated to restrict loading on each circuit below 500 MW so that under contingency outage of any one of the circuits, loading on other circuit does not exceed its thermal limit (approx. 850 MW). Commissoning of Rajarhat – Purnea 400kV D/c (one ckt. via Farakka & other ckt. via Gokarna), would mitigate the problem

(10)-g **400 kV Khalgaon-Biharsariff corridor :** Barh and Patna are high voltage prone areas, particularly during October to March. Operational measures to control voltage should be taken so to avoid opening of lines in Khalgaon-Barh-Patan-Balia corridor to the extent possible.

(10)-h **Constraints in export of power from W3 zone :** To minimize congestion in export of power from W3 zone in Chattisgarh, all efforts should be made to minimise outage of lines emanating from this zone to the neighbouring parts of the Grid. High capacity corridor for transfer of power from IPP projects being implemented with commissioning targets from Nov'13 to Dec'15, would relieve the constraints.

(11) **IMPORT LIMIT FOR NORTHERN REGION FOR JULY 2013:** System Studies for peak demand scenario of July 2013 were carried out for cases of import by Northern Region varying from 8200MW to 11300MW. Load flow and stability studies were carried out for base cases and all critical contingency cases. The studies have established that Northern Region can import up to 9750 MW in a reliable manner and the system would remain secure under all critical 'N-1' as well as 'N-1-1' contingency outages as per planning criteria.

(12) **OPERATION OF MUNDRA – MAHENDRAGARH HVDC LINK :** Power flow on the ± 500 kV, 2500 MW HVDC bi-pole line from Mundra-Adani to Mohindergarh in Haryana, is being restricted to 1500MW (1250 MW + 20% over load). A run back scheme to trip some of the generating units at Mundra has been implemented as a Special Protection Scheme (SPS) which caters to operational 'N-1' contingency without causing any power flow diversion on to AC network. In view of this, the line can be operated at higher power order and operational security of grid can be increased as this would enable to regulate flow on AC lines in WR-NR corridor. It is also desirable to take advantage of the inherent power modulation capability of the HVDC and enhance the transfer capability between the Western & Eastern Regions. In situation like the ones under which grid disturbances of July 2012 occurred, this can help in maintaining grid security. The Task Force would therefore suggest that capability of the Mundra-Mohindergarh HVDC line be optimally utilized by enhancing the power order with the availability of the run back scheme. It would also be helpful to take advantage of any capacity available on this HVDC link under contingency of outage on any NR – WR inter-regional line. The HVDC Talcher Kolar line is being operated at its full capacity with SPS for shedding of loads in Southern region and simultaneous tripping of units in Tacher STPS. The

Mundra HVDC should also be operated on similar principle. Increased power dispatch through Mundra-Mohindrgarh HVDC line factoring SPS will facilitate transfer of additional power to Northern region during its need in summer peak period.

(13) **DATA TELEMETRY AND PHASOR MEASUREMENT :** Real time data is vital for taking decisions during grid operation. There are Regulatory provisions putting the responsibility of providing telemetry to the Load Dispatch Centre on the individual users who get connected to the grid. However, this has not yielded desired results and data from a number of Generating Stations / Substations is still not available at the LDCs. The Task Force is of the view that a pragmatic approach in ensuring data availability is needed. Effective solution would be to have an integrated approach with single agency responsibility. The Task Force also deliberated upon the benefits of the scheme for enhancement of data acquisition through synchro-phasor based WAMS, employing PMUs and it emerged that there was a need for understanding the benefits and development of applications related to synchro-phasor based monitoring system.

(14) **REACTIVE SUPPORT BY GENERATORS FOR MAINTAINING PROPER VOLTAGE PROFILE IN THE GRID:** During the Task Force deliberations, issue of participation of generations in reactive power management towards controlling voltage profile in grid also came for discussion. Generating units have reactive capability which is meant for providing operational reactive support to grid for maintaining proper system voltages, appropriate dynamic response and service reliability. However, it was generally observed that generators shy away from providing full reactive support taking shelter under pretext of operating conditions limiting their capabilities. In this context, there is a need to validate reactive

capabilities of generators in a uniform manner to arrive at capability parameters which should be used in planning and operation of grid. Voltage profile management through reactive power control by coordinated adjustment of tap ratio of generator transformers is also an important area requiring attention. The task force recommends that full reactive capability of generators should be available for voltage regulation and there should be mechanism to compensate the generator for any loss of active generation in process of providing required reactive support.

(15) **TUNING OF POWER ELECTRONIC DEVICES AND PSS :** The Indian power network has several HVDC links and FACTS devices installed at various points of time. The HVDC and FACTS devices have controllers embedded in them to take advantage of their capability to assist in stabilising the network during disturbed conditions. These controllers were tuned during their commissioning phase as per simulation studies based on network configuration as envisaged at that stage. However, while the network has been expanding, only occasional re-tuning of some of the controllers has been done on specific requirement but no comprehensive retuning of HVDC/FACTS controllers has been undertaken. Some of these systems like the 2 x 250 MW, Vindhyachal back-to-back link and the Rihand - Dadri 1500 MW HVDC bipole have been tested and commissioned in the late 80's/ early 90's and the grid network in which they are operating today is significantly different from that for which their controllers were tuned. For ensuring their optimal support for grid stability, all these devices should be re-tuned corresponding to simulation of updated network and in future, regular update at interval of 3-4 years should also be done.

Power System Stabilizers (PSS) as part of the generators installed in the network are also critical for damping the local area oscillations and imparting stability to the networks. Optimal tuning of PSS also enhance effectiveness of other HVDC and FACTs controllers in supporting overall/

inter-area stability. Necessary exercise to retune PSS should be undertaken at interval of 3-4 years or even earlier depending on network additions in vicinity of specific generators.

(16) **REVIEW AND CORRECTION OF RELAY SETTINGS:**

The Enquiry Committee under Chairman, CEA which analyzed the grid disturbance recommended an extensive review and the audit of the protection system. The Task Force constituted a Sub-Committee comprising engineers from CTU, STU, NTPC, Tata Power, ABB and IPPs which deliberated on the issues concerning protection system and submitted its report covering recommendations on methodology for relay settings, format for audit data & check list for protection audit and on protection system management issues. The recommendations of the protection sub-committee are given in Chapter-9 of the report. The sub-committee is further in process of carrying out a case study to serve as model for calculations of relay settings and a report thereon will be submitted shortly.

The Task Force is of the view that for proper protection coordination, all utilities should follow the guide lines and get their protection system audited from time to time as per the recommended methodology for relay settings, data format and checklist as specified in Chapter-9 of this report. A data base of the settings of various relays also needs to be created, kept updated and verified during the relay audit. The data based may be maintained with the Regional Power Committees. Audit of protection system should be made mandatory by the CERC and SERC's in their regulations.

The Task Force is also of the opinion that an Internationally reputed consultant may be appointed to carry out studies to determine the relay settings for the complete network at 220kV and above and also carry out the settings at site in coordination with the CTU and STU's. The comprehensive exercise should be completed in a time bound manner in the next one year.

The Task Force has also observed that many of the utilities do not possess well trained and dedicated group to carry out studies for calculations for relay settings. The Task force strongly recommends that a dedicated group is required to be constituted and trained in all Utilities to carry out computer aided studies for relay settings. It also recommends that for settings of critical transmission lines and corridors the relay setting calculations be validated by simulations on the Real time digital simulator (RTDS) available with CPRI and PGCIL.

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CHAPTER – I

1. INTRODUCTION

1.1 Two major grid disturbances took place in the NEW Indian grid on the last two consecutive days of July 2012. The first disturbance took place in the Northern Region in the early hours of 30th July 2012 which resulted in failure of the Northern Regional Grid which was at that time meeting a load of around 36,000 MW. Subsequently, there was another grid disturbance in the Noon of 31st July 2012 resulting in failure of the Northern, Eastern and the North Eastern Regional grids. Ministry of Power constituted an Enquiry Committee headed by Chairman, CEA to analyze the causes of these disturbances and to suggest measures to avoid recurrence of such disturbances. The Committee inter alia recommended (Para 9.19) constitution of a Task Force to study the grid security issues.

"9.19 Formation of a task force to study the grid security issues:

It was felt that a separate task force may be formed, involving experts from academics, power utilities and system operators, to carry out a detailed analysis of the present grid conditions and anticipated scenarios which might lead to any such disturbances in future. The committee may identify medium and long term corrective measures as well as technological solutions to improve the health of the grid."

1.2 Accordingly, Ministry of Power vide letter No. 11/48/2012-PG dated the 13th December 2012, constituted a Task Force on Power System Analysis under Contingencies. The Terms of Reference and the composition of Task Force are given in Annexure-I. The Terms of Reference of Task Force broadly cover detailed analysis of the network behavior under normal conditions, under line outage and generator outage contingencies and under faulted conditions, review of the philosophy of operation of protection relays, review of defense mechanism viz. islanding & load shedding schemes and technological options to improve the performance of the grid. The Task Force included representatives from the utilities, grid operators, academia & manufacturers. Shri A.K.Asthana, Advisor, Reliance Power Transmission (former Chief Engineer CEA), and Shri P.K.Pahwa, Member Secretary, NRPC were co-opted to assist the Task Force.

1.3 The Task Force met seven times and discussed at length the various issues affecting the operation of the grid in a secure manner. The Task Force also invited several experts from the industry to deliberate on various issues relating to new technologies and performance of operation of existing islanding schemes etc and has greatly benefited by these discussions. The Task Force constituted two Sub-Committees – Study Sub-Committee for carrying out the system simulation studies corresponding to various extreme operation conditions in the grid both under normal and faulted conditions; and Protection Sub-Committee to examine the philosophy of relay and protection coordination adopted by the various utilities and also to evolve a common philosophy for relay and protection coordination in the integrated grid and also methodology for auditing and revision of protective relay setting at frequent intervals. The Task Force also deliberated on other important issues concerning safe and secure operation of grid such as operational frequency band, Special System Protection Schemes (SPS) and islanding schemes, operation of HVDC and TCSC controllers and security criteria for operational planning. Issues that emerged in these discussions and specific recommendations there on are detailed in subsequent chapters of this report.

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Annexure-I

अध्यक्ष का कार्यालय
डा०सं० 5301
दिनांक 18/12/12
कें० वि० प्रा०

Sent to M(GO&D)/M(PS)
17/12

No. 11/48/2012-PG
Government of India
Ministry of Power
*****

Shram Shakti Bhawan, Rafi Marg,
New Delhi, December 13, 2012

ORDER

Subject: Constitution of a Task Force on Power System Analysis Under Contingencies - regarding.

In pursuance of the recommendation 9.19 contained in the Report of the Enquiry Committee constituted by Ministry of Power after the grid disturbance of 30-31 July, 2012, it has been decided to set-up a Task Force on power system analysis under contingencies to carry out a detailed analysis of the present grid conditions and anticipated scenarios which might lead to any such disturbance in future.

2. The composition of the Task Force is as under:

(i)	Sh. V. Ramakrishna, Retd. Member (PS), CEA	-	Chairman
(ii)	Prof. S.C. Srivastava, Electrical Engineering Deptt., IIT(K)	-	Member
(iii)	Prof. A. Kulkarni, Electrical Engineering Deptt., IIT(B)	-	Member
(iv)	Representative of POSOCO (GM level or above)	-	Member
(v)	Representative of CTU (GM level or above)	-	Member
(vi)	Representative of ABB India (GM level or above)	-	Member
(vii)	Representative of Tata Power Delhi Distribution Ltd (GM level or above)	-	Member
(viii)	Shri D. K. Srivastava, Director, GM Div., CEA	-	Member Secretary

3. The Terms of Reference of the Task Force are as follows:

(i) To carry out a detailed analysis of the present grid conditions and anticipated scenarios which might lead to any such disturbances in future.

(ii) To identify medium and long term corrective measures as well as technological solutions to improve the health of the grid.

(iii) To analyse the system behavior under different network status (Sub-transient State / Transient State)

(iv) To analyse the system behavior in case of tripping of lines at 400 kV / 765 kV/ HVDC.

(v) To analyse the system behavior under outage of generators affecting the frequency of the grid.

(vi) To suggest the remedial measures for preventing the grid disturbance on account of the above contingencies.

CE|GM Member(GO&D)

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(vii) To study other relevant issues related to grid security in totality.

(viii) To study defense mechanism adequacy and supplementary requirements.

(ix) To suggest setting of relays for under frequency and rate of change of frequency relays.

4. The Chairman of Task Force, if deemed necessary, may co-opt/invite additional experts/members.

5. The Task Force will submit its report to the Ministry of Power within a period of 6 months from the date of this order.

6. All administrative and logistics expenses on account of this Task Force will be borne by the Central Transmission Utility i.e. Power Grid Corporation of India Limited.

7. An honorarium/sitting fee of Rs. 3000/- per meeting subject to the ceiling of Rs. 15000/- per month will be paid to the non- official members by the Central Electricity Authority.

Yours faithfully,

(G. Kanishka)
Under Secretary (PG)
Telefax : 23730264

Distribution:

Chairman & all Members of the Task Force

Copy to :

1. Secretary (Power)
2. Chairperson, CEA alongwith copies for distribution to the Members of Task Force.
3. Additional Secretary (AL), Ministry of Power
4. Additional Secretary (DC), Ministry of Power
5. Member (GOD), CEA
6. All JSs/JS&FA/EA in the Ministry of Power
7. Chief Controller of Accounts, Ministry of Power
8. NIC for updating the website.

CHAPTER – II

2. CRITICAL ISSUES AFFECTING GRID SECURITY

2.1 In the First Meeting of the Task Force held on 8th January 2013, the Members of the Task Force discussed in detail, the Terms of Reference of the Task Force. It was noted that the Task Force was mandated to carry out the detailed analysis of the present grid conditions and the anticipated scenarios in future, to analyze the system behavior under normal conditions, contingency of outage of EHV transmission system at 400 kV/765 kV/HVDC, outage of generators and under different network status viz. sub-transient & transient conditions.

2.2 Towards the above objective, as a first step, an analysis of present grid conditions and factors affecting operation of grid was done as detailed in Chapter-3 of this report.

2.3 For the near future, it was felt that critical operation conditions were likely to prevail during the summer peak load conditions of Northern Region when it is likely to import substantial power from the neighboring regions. Therefore, it was proposed to simulate the system conditions corresponding to July – September 2013 and to study the performance of the grid under normal and abnormal conditions. A Sub-Committee was constituted with engineers from CTU, POSOCO, Prof. Kulkarni from IIT, Mumbai & Shri A.K.Asthana Co-opted Member. Study Report for July – September 2013 prepared by this sub-committee is included in Chapter-4 of this report with the objective that this should serve as a sample report for all future studies.

2.4 It was noted by the Task Force that such exercises (as in Chapter-3 and Chapter-4 of this report) should be done on a regular basis and suitable operation strategy worked out. Studies are required for all time horizons starting from network expansion planning for long-term to operational planning in the short term as well as the medium term conditions. The exercises should be repeated taking into account the anticipated network topology and the anticipated generation and load patterns. This exercise should be done by a dedicated group of System Experts and the strategy for real time operation should be based on these operational planning studies. Load dispatchers should also be appraised of findings of operational planning studies on a regular basis.

2.5 Load dispatcher needs a vivid picture of security impact of various contingency depletions under real time operating conditions so that he may take necessary actions towards ensuring grid security in best possible manner. For this, the load dispatchers at National, Regional and State levels should be equipped to carryout loadflow, contingency and stability studies taking data from SCADA system for assessing safe transmission capacity on a real-time basis. It was noted that real time contingency analysis software exists at the load dispatch centers. However, due to quality of real time data, this tool was not being utilized effectively. Necessary mechanism to improve real time data quality so as implement real time contingency analysis and stability studies needs to be put in place at the earliest.

2.6 The Task Force also debated on the need of having a Transmission Operational Planning Criteria different from Transmission Planning Criteria of CEA which forms basis for network expansion planning. It was debated that while ‘N-1’ or ‘N-1-1’ may suffice for expansion planning, operational security may require ‘N-x-1’ , “N-x-1-1’ or ‘N-x-2’ or even higher, particularly in view of outage of multiple elements. However, it needs to be kept in view that restricting dispatches based on security criteria much higher than that adopted for planning would result in drastically curtailing power supplies in an already deficit scenario. As such, violation of higher security criteria has to be used as a trigger for alert, alarmed or emergency status. Further, Special Protection Schemes (SPS) which are kept as reserve to take care of expansion uncertainties may be factored in operational planning so as to arrive at enhanced transmission capacities without any compromise on grid security. It is felt that further detailed deliberations on this subject are required.

2.7 The Task Force further noted that following the grid disturbance and the intervention of the Central Regulatory Commission, the integrated grid was operating in a much narrower band of frequency regime and the percentage of time the system was operating below 49.7 Hz was very small. To further narrow down the frequency regime of operation, the Enquiry Committee had also recommended that the provisions of IEGC with regard to governor action should be implemented so that primary frequency response from the generators was available in the real time operation. The Task Force debated further on issues. It was noted that system operation based on day ahead and real time load forecast together with mechanism for secondary and tertiary control through maintaining of spinning reserves has to be implemented expeditiously so that auto-controlled Load Generation Balance mechanism through governor action can be implemented. Balancing power can be requisitioned either through a mandatory participation enforced through regulation or better through creation of market for ancillary services. Mechanism for settlement of deviations would also require a change from frequency linked UI tariff regime to a system of settlement in kind and penalty for exceeding deviations from specified limits. The existing UI mechanism needs to be reviewed and conflicts removed so that it does not come in the way of governor mode of operation. The Task Force suggests further deliberations on these issues so as to bring out suitable changes in regulations for consideration of the Central Regulatory Commission.

2.8 The task force also observed that integration of renewable energy in the grid is one of the biggest thrust areas. The installed generation capacity of renewable generators is expected to grow manifold in the coming years. Considering the variability and infirmity of generation from renewable resources, there was a need to have strong interconnections together with the frequency in the grid maintained in a narrower band so that energy injection from renewable sources can be safely absorbed in the grid.

2.9 During the course of the deliberations of the Task Force, it was observed that following the grid disturbance, many of the utilities were planning to have number of islanding schemes basically covering some of the generators along with some loads connected to them. The basic objective of system operation is to have an integrated grid operating with normal system parameters. Indiscriminate breaking up of the system by formation of electrical islands by removing a part of the generation and loads from the integrated grid may not be in the interest of safe and secure operation of the integrated grid. The Task Force felt that instead of planning large number of islanding scheme in an adhoc manner, it would be better to evolve some guidelines based on which proposals for islanding schemes could be formulated There is also a need to review the settings of under frequency relays and also the quantum of load shedding to be done under various system operating conditions. The issues were deliberated upon and recommendations arrived at as detailed in Chapter-5 of this report.

2.10 Real time data is vital for taking decisions during grid operation. The Task Force observed that relevant data from a number of Generating Stations / Substations was still not available at the Load Dispatch Centers despite RLDCs taking-up the issue with CERC through individual petitions. However, this is a long discussed issue in which desired success has not been achieved even after more than two decades of efforts, The Task Force is of the view that a pragmatic approach in ensuring data availability is needed. Effective solution would be to have an integrated approach with single agency responsibility. The Task Force also deliberated upon the scheme for enhancement of data acquisition through synchro-phasor based Wide Area Measurement System (WAMS), employing Phasor Measurement Units (PMUs). It emerged that there was a need for understanding the benefits and development of applications related to synchro-phasor based monitoring system. Issues on data telemetry and phasor measurement based on inputs from NLDC, POSOCO and CTU, POWERGRID and Task Force deliberations on the same are discussed in Chapter-6 of this report.

2.11 During the Task Force deliberations, issue of participation of generations in reactive power management towards controlling voltage profile in grid also came for discussion. Generator reactive capability is required to maintain proper system voltage levels, provide appropriate dynamic reserves and assure service reliability. However, it was generally observed that generators shy away from providing full support taking shelter under pretext of operating conditions limiting their capabilities. In this context, there is a need to validate reactive capabilities of generators in a uniform manner so as to arrive at realistically attainable values which should be used in planning and operation of grid. Voltage profile management through reactive power control by coordinated adjustment of tap ratio of generator transformers is also an important area requiring attention. Notes on Reactive capability testing of generators and Generator tap co-ordination for reactive power control contributed by Shri P. Pentayya, GM, WRLDC is being included as Chapter-7 of this report. The Task Force recommends that full reactive capability of generators should be available for voltage regulation and there should be mechanism to compensate the generator for any loss of active generation in process of providing required reactive support.

2.12 The Task Force also reviewed the operation of Controllers of Power Electronic Devices (PED) viz. HVDC links and TCSCs. It was observed that the settings of the controllers of the PEDs were done at the time of commissioning of these devices and were not very effective under the present conditions. The Task Force deliberated on the performance of the PEDs with the experts from the Manufacturers and is proposing to address the issue/methodology and frequency for revising/modifications to the Controllers of PEDs. This would require intricate studies and tuning/re-tuning of PEDs based on results of studies. Task force recommends that consultant of international repute should carry out studies and retuning of controllers should be done. This should be reviewed regularly after every 3-4 years. Recommendations on the issue, is included in Chapter-8 of this report.

2.13 The Task Force also noted from the Enquiry Committee report that one of the factors that led to the initiation of the grid disturbance on 30th & 31st July 2012 was the tripping of lines in the major inter-regional corridors in a mal operation of distance relay known as 'Load Encroachment' which may happen even if there is no fault in the nearby transmission system, and may occur when the line carries very heavy load. The Enquiry Committee under Chairman, CEA which analyzed the grid disturbance recommended an extensive review and the audit of the protection system. The Task Force noted that though there is a CBIP manual delineating the philosophy for coordinated operation of the relay system, practice adopted in protection coordination of transmission lines, transformers and generators was at variance with respect to CBIP manual and it also varied from utility to utility. It was, therefore, felt by the Task Force that a separate Sub-Committee constituting Engineers from industry and utilities who are specifically dealing with protection/relay issues should analyze the practice being adopted by the various utilities and evolve a common philosophy so that the settings of the various relays are suitably coordinated and the protection system operates in an efficient manner.

2.14 Accordingly, a sub-committee was constituted which has deliberated on the philosophy of relay and protection coordination and has come out with detailed recommendations on methodology for relay settings, audit of protection system and on management issues related to protection system. Recommendations of the protection sub-committee are included in Chapter-9 of this report. Further to this, the sub-committee is in process of carrying out a case study to serve as model for calculations of relay settings, and a report thereon will be submitted shortly. The Task Force is of the view that for proper protection coordination, all utilities should follow the guide lines and get their protection system audited from time to time as per the recommended methodology for relay settings, data format and checklist as recommended by the Protection Sub-Committee.

2.15 A data base of the settings of various relays also needs to be created, kept updated and verified during the audit. Data regarding settings of relays in their network should be compiled by the CTU and STUs and furnished to the RLDC and SLDC respectively and a copy should also submitted to RPC for maintaining the data base. Report of every audit should be submitted to RPC and also the RLDC/NLDC by the CTU and to the SLDCs by the STU's. Audit of protection system should be made mandatory by the CERC and SERC's in their regulations. This should be specified by the regulatory commissions in their Grid Code.

2.16 The Task Force is of the opinion that an Internationally reputed consultant may be appointed to carry out studies to determine the relay settings for the complete network and also carry out the settings at site in coordination with the CTU and STU's. The comprehensive exercise should be completed in a time bound manner within the next one year.

2.17 The Task Force has also observed that many of the utilities do not possess well trained and dedicated group to carry out studies for calculations for relay settings. The Task force strongly recommends that a dedicated group is required to be constituted and trained in all Utilities to carry out computer aided studies for relay settings. It also recommends that for settings of critical transmission lines and corridors the relay setting calculations be validated by simulations on the Real time digital simulator (RTDS) available with CPRI and PGCIL.

2.18 There is also a need for periodic review of protection coordination and relay settings to take care of changes in network topology due to addition of new system elements – generating units, transmission lines, etc. The Regional Power Committee which is mandated to discuss issues relating to coordination of grid operation among the various utilities in the Region should on a quarterly basis review the protection & relay coordination issues and ensure carrying out of the necessary modifications in the relay settings.

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CHAPTER - III

3. ANALYSIS OF PRESENT GRID CONDITIONS

3.1 As on 31.03.2013, the total installed generation capacity on all India basis was 223,343 MW including an installed capacity of 167,408 MW (NEW) in the Northern, Eastern, Northern Eastern and Western grid and 55,859 MW in the Southern Regional grid. In addition, there was 34,444 MW of grid interactive captive generation (1 MW and above). The details of the installed capacity is given in the Table below:

(As on 31-03-13)

SL. NO.	REGION	THERMAL COAL	GAS	DSL	TOTAL	Nuclear	HYDRO (Renewable)	R.E.S.@ (MNRE)	TOTAL
1	Northern	32413.50	4781.26	12.99	37207.75	1620.00	15467.75	5589.25	59884.75
2	Western	49257.01	8988.31	17.48	58262.80	1840.00	7447.50	8986.93	76537.23
3	Southern	25032.50	4962.78	939.32	30934.60	1320.00	11353.03	12251.85	55859.48
4	Eastern	23457.88	190.00	17.20	23665.08	0.00	3981.12	454.91	28101.11
5	N. Eastern	60.00	1187.50	142.74	1390.24	0.00	1242.00	252.68	2884.92
6	Islands	0.00	0.00	70.02	70.02	0.00	0.00	6.10	76.12
7	All India	130220.89	20109.85	1199.75	151530.49	4780.00	39491.40	27541.71	223343.60

Captive Generation Capcity in Industries having demand of 1 MW or above, Grid interactive(as on 31-03-2011)=34444.12 MW

@ Renewable Energy Sources (RES) includes Small Hydro Project(SHP),Biomass Power(BP), Urban & Industrial waste Power(U&I), Wind Energy and Solar Power.

3.2 The above installed capacity of 223 GW was able to meet peak demand of the order of only 123 GW. Utilization of installed capacity was on lower side due to lack of adequate availability of Coal and Gas and other factors including dispatch restrictions due to transmission congestion. As a result, we could not meet the peak demand and energy requirements and deficits were in the range of 4-15.5% of energy requirement and 5.5-16.5% of peak requirements. Typical values region wise for the month of January, 2013 was as under:

Region	Energy (MU) Requirement	Deficit %	Peak Demand (MW)	Deficit %
Northern	24,875	-10.2	39,861	-10.9
Western	25,561	-5.9	39,644	-5.8
Southern	24,628	-15.6	35,648	-16.6
Eastern	8,560	-3.7	13,905	-5.4
North Eastern	992	-6.8	1,943	-6.6

3.3 The frequency profile of the grid has improved over the years and in the recent past the frequency profile is mostly in the range of 49.7 – 50.2 Hz in the NEW grid as well as in the SR grid. Details of frequency profile in the NEW grid and SR grid are given in the table below:

NEW GRID										
FREQUENCY PROFILE		< 48.5	48.5 - 49.5	< 49.5	49.5 - 50.2	>50.2		Max. Freq	Min. Freq	Avg. Freq
% TIME	Apr-12	0.00	2.38	2.38	93.68	3.94		50.66	49.08	49.9
	May-12	0.00	10.82	10.82	87.82	1.36		50.75	48.82	49.8
	Jun-12	0.00	19.95	19.95	78.66	1.39		50.68	48.75	49.7
	Jul-12	0.00	24.38	24.38	73.59	2.03		51.21	49.79	49.68
	Aug-12	0.00	1.57	1.57	89.72	8.71		50.65	48.82	49.95
	Sep-12 (till 16 sep)	0.00	0.60	0.60	83.73	15.67		50.65	48.96	50.02
FREQUENCY PROFILE		<49.0	49.0-49.7	<49.7	49.7-50.2	>50.2		Max. Freq	Min. Freq	Avg. Freq
% TIME	Sep-12 (17 Sep onwards)	0.00	3.22	3.22	84.09	12.69		50.65	48.96	50.03
	Oct-12	0.00	3.33	3.33	90.39	6.28		50.61	49.37	49.98
	Nov-12	0.00	0.05	1.79	85.83	12.38		50.63	49.33	50.02
	Dec-12	0.00	4.39	4.39	84.1	11.51		50.63	49.25	50
	Jan-13	0.00	4.63	4.63	80.95	14.42		50.78	49.3	50.01

SR GRID										
FREQUENCY PROFILE		< 48.5	48.5 - 49.5	< 49.5	49.5 - 50.2	>50.2		Max. Freq	Min. Freq	Avg. Freq
% TIME	Apr-12	0.00	7.79	7.79	91.28	0.93		50.66	48.66	49.69
	May-12	0.00	5.61	5.61	94.01	0.38		50.63	48.81	49.7
	Jun-12	0.00	7.83	7.83	91.03	1.14		50.79	48.86	49.68
	Jul-12	0.00	0.00	6.95	92.18	0.87		50.61	48.81	49.69
	Aug-12	0.00	3.17	3.17	95.57	1.26		50.55	48.86	49.75
	Sep-12 (till 16 sep)	0.00	1.68	1.68	95.88	2.44		50.58	49.12	49.81
FREQUENCY PROFILE		<49.0	49.0-49.7	<49.7	49.7-50.2	>50.2		Max. Freq	Min. Freq	Avg. Freq
% TIME	Sep-12 (17 Sep onwards)	0.00	0.00	18.37	81.43	0.2		50.51	49.12	49.79
	Oct-12	0.00	8.26	8.26	89.38	2.36		50.73	49.19	49.86
	Nov-12	0.00	0.00	4.16	91.85	3.99		50.69	49.15	49.91
	Dec-12	0.00	3.68	3.68	93.4	2.92		50.87	49.28	49.9
	Jan-13	0.00	0.00	3.78	91.41	4.81		50.87	49.24	49.94

3.4 It is seen that improvement in frequency is in term of overall increase in average level and not that much in narrowing down the frequency band. With increase in average frequency, increase in percentage of time frequency is above 50.2 Hz is also being observed. This is not a good indication. It also noted that the frequency has not gone below 49.0 Hz after

September 2012.There is scope for improvement and establishment of the tighter frequency band of operation together with reduction in load curtailment with increased utilization of generation while maintaining better grid security. This requires better management of the schedules by the various utilities by proper load management and ensuring stable frequency through Free Governor Mode of Operation of the generators together with secondary and tertiary control mechanism.

3.5 Integration of renewable energy in the grid is one of the biggest thrust areas. The installed generation capacity of renewable generators is expected to grow manifold in the coming years. Considering the high variability and unpredictability of generation from renewable, the injection from renewable sources can be safely absorbed in the grid if the frequency in the grid is maintained close to the nominal operating frequency.

3.6 One of the problems affecting the operation of the grid is prevailing high voltages in the grid especially in the Western Region during May to October. This partly due to less loading of 400 kV lines and even after exhausting management of all other reactive power sources there is a need to open number of 400 kV lines to control the high voltages which results in reduced system reliability.

3.7 The Central Transmission Utility (CTU) has planned installation of number of shunt reactors in the grid to control the over voltages. However, it is observed that even the generator buses face high voltages. Therefore, there is need to review the tap setting on all generator transformers and take advantage of the reactive capability of the generators and regulation of the excitation system so that the voltage profile of the grid is properly managed. Additionally arrangements may need to be made for allowing operation of hydro generators in synchronous condenser mode. In fact, the CEA (Technical Standards for Connectivity to Grid) Regulation 2007, specifies synchronous condenser operation as a desirable feature in hydro generators of 50MW and above. To encourage synchronous condenser operation of hydro generators, CERC may like to consider some tariff incentives to these generators.

3.8 Certain parts of the Northern grid specifically in Punjab, Western Uttar Pradesh, Uttarakhand & J&K face severe low voltage problems especially in July to September in Punjab and during winter months in the hill states.. There is need for installation of adequate shunt capacitors to address the issue of low power factor of incident loads. There is an urgent need to address this issue as otherwise there an apprehension of voltage instability. Powergrid is also embarking on a program of installation of number of Static VAR Compensators (SVC) in the grid to provide dynamic reactive support. The location and size of SVCs have been finalized in consultation with CEA and the state utilities and the process of implementation has taken off. It is anticipated that these SVCs will be commissioned in a progressive manner from 2015 to 2017. For further improvement in this area, application of STATCOM, which are state of art equipment for providing dynamic Var support for better voltage stability, should also be considered.

3.9 **General Aspects Impacting System Security**

3.9.1 The transmission system is planned based on certain assumptions like generation, demand projection, dispatch scenarios and credible contingencies. However, many a times, there is large mismatch between projection and actual scenario due to factors beyond control of transmission planners. Under skewed dispatch like high surplus in one part of the country and deficit in another part, transmission constraints are experienced.

3.9.2 It has been observed that many of the constraints are diurnal or seasonal in nature. The constraints keep moving from one corridor to other based on load and generation disposition, commissioning or delay in commissioning of generation / transmission projects etc. Transmission Constraints experienced during different seasons are detailed in the subsequent sections of this report.

3.9.3 **Uncertainty in growth rate:** Planning of transmission system is done on the basis of anticipated generation growth and demand projections in National Electricity Plans and Electric Power Surveys. However, in actual operation the demand incident in each state or region or country as a whole is dependent inter-alia on the following factors:

- Growth in other sectors of the economy
- Behaviour of the South West monsoon and/or North East monsoon
- Supply side constraints within each state or region.
- Transmission constraints
- Financial viability of DISCOMs in the state which has a bearing on power purchase
- Rural electrification programs

3.10 **Transmission Constraints in the System:**

3.10.1 **Congestion in ER-SR and S1-S2 corridors – Transmission constraint experienced throughout the year.**

(a) 400 kV Vijaywada-Nellore is an approximately 350 km long line with line reactors at both ends. The sustained loading on this line is around 540 MW per circuit. Under N-1 condition the flow on the remaining circuit touches 750 MW and the angular difference between Vijaywada and Nellore exceeds 30 degrees. The D/C line is loaded heavily due to increase in upstream generation in Vemagiri area, increase in import from eastern region through Gazuwaka and delay in downstream generation (including Kudankulam). Import transfer capability of Southern Region is limited by the high loading of this corridor.

(b) S1 bid area consists of Andhra Pradesh and Karnataka and S2 comprises of Tamil Nadu and Kerala. High loading of 400 kV Hosur-Salem restricts the transfer from S1 to S2 area. Constraint is due to Delay of commissioning of Generating units in S2 area and no addition of internal generation in Tamilnadu.

(c) The above ER-SR and S1-S2 constraints would get relieved on addition new generating units in Tamil Nadu and southern Andhra Pradesh. and the additional Vijayawada-Nellore-Thiruvalam-

Kalivandapattu 400kV D/c line is under construction on priority by CTU.

3.10.2 Generation evacuation from Mundra generation pocket in coastal Gujarat – Transmission constraint experienced throughout the year:

Three large power stations with an aggregate capacity of close to 10,000 MW have come up near Mundra in coastal Gujarat as under with the indicated evacuation

i. APL Mundra having 4620 MW capacity (entire capacity commissioned) planned with eight (8) 400 kV outlets with Twin Moose and one 2 x 1250 MW HVDC bipole as well as four (4) 220 kV outlets.

ii. CGPL Mundra UMPP having 4150 MW ultimate capacity (four units with total installed capacity equivalent to 3320 MW already in commercial operation) with six (6) 400 kV outlets with Triple Snowbird conductors.

iii. Essar Vadinar having 1200 MW capacity (entire capacity commissioned) planned with four (4) 400 kV outlets with Twin Moose.

The Mundra area in Kutch Gujarat is also a high wind zone with substantial wind generation capacity which peaks during the April-August period. While other transmission lines planned for power evacuation from this area have been commissioned, 400kV APL Mundra – Zerda two double circuit lines (twin Moose conductor) and 400kV Essar Vadinar – Amreli double circuit line (twin Moose conductor) are yet to be commissioned. Delay in commissioning of these AC lines in Gujarat and also absence of adequate parallel AC system from Mundra to Mahendragarh, led to a situation in which full capacity of the 2 x 1250 MW HVDC bi-pole from Mundra to Mahendragarh along with its AC interconnecting lines to Dhanaunda(HVPNL) and Bhiwani(PGCIL) is not usable. Delay in commissioning of HVPNL transmission system from Dhanaunda to Daulatabad to Gurgaon and from Dhanaunda to Sonipat is also a factor in this. Earlier dispatch on this was being restricted to 1250 MW and subsequently the restriction level was increased to 1500MW factoring 20% overload capacity of HVDC terminals. Dispatch restriction on this HVDC link also constraints other dispatches from Mundra complex. System Protection Schemes (SPS) have been installed at APL Mundra to take care of the eventuality of tripping of any of the lines from the Mundra complex. Safe operating limit evaluated factoring SPS scheme and integrated operation of HVDC and AC system, could give increased dispatch with enhanced security.

Mundra – Mahendragarh HVDC is a tie line established under Section 10 of Electricity Act, 2003. It is not a radial line. As such its loading with respect to N-1 criteria should be based on testing the networks through load flow and stability studies taking parallel operation of integrated system. Higher dispatch on this line would also facilitate achieving higher grid security. In a situation, like the one which caused grid disturbance on 30th and 31st July, 2012, increasing dispatch on Mundra – Mahendragarh HVDC bi-pole line could be helpful.

It may further be noted that a similar HVDC line of 2000MW capacity from Talcher STPS to Kolar in Southern region has been constructed by Powergrid for evacuation of 2000 MW capacity. This link has subsequently been upgraded to 2500 MW by providing more cooling on the converter transformers and additional filters for the enhanced capacity. The link is operated to its full capacity as and when required. For ‘N-1’ contingency of outage of a pole, relief is made available through SPS by load relief from constituents in Southern Region and tripping of units at Talcher.

The Mundra – Mahendragarh HVDC line connects Western region, which has surplus power in the monsoon months, and Northern region, which has high load during summers on account of weather beating loads as well as agricultural loads of Kharif crops in Haryana, Punjab and Western UP. In the interest of both the regions, the Mundra – Mahendragarh bi-pole needs to be operated with enhanced dispatch.

3.10.3 **High loading of 400 kV Rourkela-Talcher D/C – Transmission Constraint Experienced during April to June:**

This constraint is experienced when availability of hydro power in ER as well as in SR is low whereas the demand is high. Low generation at

Talcher complex also aggravates the high loading on Rourkela-Talcher. 400kV Rourkela-Talcher D/C is the common corridor for transferring power both for Orissa as well as for SR.

High import by Orissa (particularly in south Orissa) together with export to SR via HVDC Talcher_Kolar and Gazuwaka B/B, leads to increased loading of 400 kV Rourkela-Talcher D/C. In addition, occasional over drawal by West Bengal and high injection from WR caused further increase in loading of this line as it reduces the counter flow from Kolaghat to Baripada. High loading of this corridor limits the export transfer capability of ER towards SR. The sensitivity of outage of one circuit of Rourkela-Talcher on the other circuit is around 60%. In order to limit the loading on Rourkela-Talcher to its thermal limit (approx. 850 MW) on N-1 contingency of the other circuit, either line is not allowed to get loaded beyond 530 MW. Talcher – Rourkela 400 kV D/c (quad) which may have mitigated the problem, was awarded for implementation by private sector under competitive bidding route more than three years ago. However, work on the line has not yet started. Issues with implementation of this line need to be resolved at the earliest.

3.10.4 Lack of redundancy in Nathpa Jhakri, Karcham Wangtoo and Baspa evacuation system – Transmission constraints experienced during July to September :

Evacuation of 1500 MW NJHPS, 1000 MW KWHEP & 300 MW Baspa HEP is through 400 kV Jhakri-Nalagarh D/C, 400 kV Jhakri-Panchkula-Abdullapur D/C and 400 kV Karcham-Abdullapur D/C. All the generators in the complex generate at sustained overload of 10-20 %. The load on evacuating lines is unevenly distributed. The lines from Jhakri towards Nalagarh/Patiala (Punjab) are generally more loaded than those from Karcham towards Abdullapur (Haryana). Any N-1 contingency causes the flow on remaining circuits from Jhakri to reach close to the thermal capacity of the conductors. The emergency shutdown of 400 kV Nalagarh-Patiala-I requested on 19-08-2012 could be facilitated only after backing down of generation at Karcham, AD Hydro and Malana HEP. Oscillations were observed on 23rd August 2012 after the simultaneous tripping of 400 kV Karcham-Abdullapur D//C and one of 400 kV Panchkula-Abdullapur D/C lines (SPS did not operate). The generation in the complex was 3000 MW. This establishes the need for tuning of Power System Stabilizers (PSS) of the generating units. At Karcham Wangtoo such an exercise was done in April 2013 and similar exercise is also required at Nathpa Jhakri. With the commissioning of Parbati (III)-Amritsar and Koldam-Ludhiana 400kV D/c alternate paths would exist to supply power to Punjab. POWERGRID has commissioned a 400/220kV substation at Panchkula. It is, however, understood that the power drawn through this ICT is very low. Commissioning of above lines and connection of additional load at Panchkula would relieve Nathpa Jhakri – Patiala 400kV D/C line. Further series compensation of Karcham Wangtoo - Abdullapur 40kV D/C line and a new 400kV D/C line from Abdullapur to Patiala has been approved. Commissioning of these elements would relieve the unbalanced loading.

3.10.5 **High Loading of 400 kV Purnea-Muzaffarpur – Transmission constraint experienced during July to September :**

During the period of monsoon high generation is available at Teesta, Tala & Chukha. Most of this excess generation along with import from NER is exported to NR through 400 kV Purnea-Muzzaffarpur D/C lines as this line provides a least impedance path since it has series compensation. This evacuation of the surplus hydro power from north-eastern part of eastern region to the northern region causes the severe overloading of 400 kV Purnea-Muzzaffarpur D/C and during July, many a times its flow crossed even 800 MW each circuit. Purnea-Biharsharif 400kV (quad) D/c being implemented by private sector under competitive bidding route and Kishanganj-Patna 400kV (quad) D/c being implemented by POWERGRID would mitigate the problem.

3.10.6 **Constraints due to wind generation in South TN – Transmission constraints experienced during July to September :**

Wind Gen. IC in TN is about 7000 MW with peak gen. reaching about 3900 MW. Many 230 kV/110 kV lines and 400/230kV ICTs at Tirunelvelli get severely stressed during wind peak in Tirunelveli area. With

Kudankulam generation commissioning the network would be additionally stressed. For this quantum of wind power, operational dispatch and load management alone is not adequate to mitigate the impact of its intermittence and variability on grid parameters. Further increase in wind power should be disallowed till appropriate technical solution of this problem is explored and implemented. Tamil Nadu has to implement 400kV D/C line from that area to Chennai area. This needs to be completed on priority to relieve the congestion in the corridor.

3.10.7 **High loading of 400 kV Farraka-Malda D/C – Transmission constraints experienced during October to March :**

(a) As monsoon depletes and winter approaches the generation at hydro stations situated at north-east part of eastern region and Bhutan start depleting. Consequently, the excess hydro power that North Eastern Region injects in ER grid decreases and subsequently NER starts drawing power from ER to meets it demand. High drawal by NER along with low generation at Tala, Chukka and Teesta causes high loading of 400 kV Farraka-Malda D/C.

(b) The 400 kV Farraka-Malda D/C is approximately 40 Km long line. The power flows through it during low hydro condition is normally utilized to meet the demand of North Bengal and contains exported power to NER and NR. This high export scenario to NER and NR and less generation at Northeast Part of ER causes a severe overloading of this line.

(c) The sensitivity of outage of one circuit of Farakka-Malda on the other circuit is around 75%. In order to limit the loading on Farakka-Malda to its thermal limit (approx. 850 MW) on n-1 contingency of the other circuit, either line is not allowed to reach 500 MW. Tripping of one circuit followed by the other can cause a partial system separation within Eastern Grid. The FSC at Purnea is also kept by-passed to reduce high loading at Farakka – Malda D/C. Rajarhat – Purnea 400kV D/c (one ckt. Via Farakka & other ckt. via Gokarna) under Eastern Region Strengthening Scheme-V would mitigate the problem.

3.10.8 **400 kV Khalgaon-Biharsariff corridor – Transmission constraints experienced during October to March :**

400 kV Khalgaon substation is connected with Biharsariff with four 400kV line among which two are direct and other two are via Banka. Power which lands at Khalgaon from Farakka and Maithon along with the power

generated by Khalgaon is evacuated through these lines. Since Barh and Patna are high voltage prone areas, many a times lines are kept open in Kahalgaon-Barh-Patan-Balia corridor to limit high voltage. Due to opening of lines the impedance of Kahalgaon-Barh path increases and more power is diverted on Kahalgaon-Biharsariff Corridor.

3.10.9 Constraint in export of power from W3 zone – Transmission constraint experienced during July to March :

The important lines emanating from this region to the neighbouring parts of the Grid are:

A. Towards Eastern Region

a. 400 kV Sterlite-Rourkela-1
b. 400 kV Sterlite-Rourkela-2
c. 400 kV Sipat-Ranchi-1
d. 400 kV Sipat-Ranchi-2
e. 220 kV Korba East-Budhipadar-2
f. 220 kV Korba East-Budhipadar-3
g. 220 kV Raigarh-Budhipadar S/C

B. Towards Madhya Pradesh

a. 765 kV Bilaspur-Seoni -1
b. 765 kV Bilaspur-Seoni-2
c. 400 kV Bhilai-Seoni S/C
d. 400 kV Korba-Vindhyachal
e. 400 kV Korba-Essar Mahan
f. 400 kV Korba-Birsinghpur S/C
g. 400 kV BALCO-Birsinghpur
h. 220 kV Kotmikala-Amarkantak-1
i. 220 kV Kotmikala-Amarkantak-2

C. Towards Maharashtra

a. 400 kV Raipur-Bhadrawati-1
b. 400 kV Raipur-Bhadrawati-2
c. 400 kV Raipur-Bhadrawati-3
d. 400 kV Bhilai-Bhadrawati
e. 400 kV Bhilai-Koradi
f. 400 kV Raipur-Wardha-1
g. 400 kV Raipur-Wardha-2

Congestion in lines towards Eastern Region (lines in **A** above) occurs during July-September when there is high demand in Northern Region and power gets wheeled from W3 to NR via Eastern Region.

Congestion in lines towards Maharashtra (lines in **C** above) occurs during October-March when there is high demand in Maharashtra which leads to high loading of Raipur-Bhadrawati, Raipur-Wardha and Bhilai-Koradi sections. Export transfer capability from W3 has increased after commissioning of 400 kV Raipur-Wardha (series compensated) D/C line but it still gets restricted when there is outage on other parallel circuits.

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CHAPTER – IV

4. CONTINGENCY STUDIES FOR JULY TO SEPTEMBER 2013 CONDITIONS

4.1 From the discussions held in the Task Force meetings, it emerged that the system conditions anticipated to occur in the coming summer months especially when Northern Region would be meeting weather beating loads along with the agricultural loads due to Kharif crops in Punjab, Haryana and Western UP simultaneously with reduced loads in WR and SR due to onset of monsoon conditions in these regions would be the most severe with the NR likely to import large quantum of power from the neighboring regions. In view of this, it was decided that the sample studies would be carried out for July 2013 conditions. To carry out the above Studies, a Sub-committee was constituted with the following Members:

1. Shri A.K. Asthana, Co-opted Member (Task Force)
2. Prof. Anil Kulkarni, IITB, Mumbai
3. Shri S.R. Narasimhan, DGM, POSOCO
4. Shri Y. K. Sehgal, COO, CTU

4.2 Load flow and dynamic simulation studies were conducted at POSOCO by the sub-committee, and report covering results of studies along with analysis of findings was brought out and the same is including, assumptions and methodology adopted for carrying out studies and the analysis of the results of the studies are given in this chapter.

4.3 The sub-committee took into account the revised manual on transmission planning criteria brought out by CEA in January 2013. With a view to start with pre-validated data and to complete the studies in the time frame available to the study sub-committee, system data files available with CTU for their planning studies corresponding to 2016-17 conditions was taken as the starting point and the data base was modified in respect of system topology and generation and load conditions corresponding to July 2013. In this process, it was noted that there were certain differences in basic network topology especially at lower voltage levels in the existing network vis-à-vis as was adopted by CTU. Accordingly, necessary validation and correction of data was ensured. Load demands were arrived from base data of July 2012 and one year growth to scale up the demands to July 2013 anticipated conditions. For the States which faced heavy deficit in July 2012 and where new generating capacity under the state control have been commissioned, the demand of the state was scaled up taking that the new generation would be used to release the unmet/dormant demand of the home state.

4.4 New generation units (Annex-I) and transmission elements (Annex-II) commissioned after July 2012 and those expected by July 2013, as listed below, were taken into account in the generation dispatch.

Annex I: New Generating Units expected by July 2013

New Units Commissioned since July 2012			Additional Units expected by July 2013		
S. No	**New Units**	**Installed capacity (MW)**	**S. No**	**Units Expected**	**Installed Capacity (MW)**
1	Rihand Stage 3	500	1	Vindhyachal St IV U#I	500
2	Chamera 3 (Unit 2 & 3)	154	2	Essar Mahan U#1	600
3	Rajwest (5 & 6)	270	3	Pipavav U#1	350
4	Paricha (Unit 5)	250	4	Ukai U#6	500
5	Rosa II (Unit 1 & 2)	300	5	Adhunik U#1	270
6	Bhilangana (Unit 1,2 & 3)	8	6	GMR U#1 and 2	700
7	CGPL (U# 1,2,3 & 4)	3200	7	NLC Exp II U#I	250
8	Sipat	660	8	Mettur St III U#1	600
9	J P Bina	250	9	North Chennai	600
10	ACBL	270	10	Palatana U#2	363
11	APL Tiroda	660	11	BALCO	600
12	Vallur (U#1)	500	12	Kudankulam APS	1000
13	MEPL	150			
14	Simhadri	1000			
15	Palatana U#1	363			
16	Koderma	500			

Annex II: New Transmission Elements expected to be commission by July 2013

Sl. No.	Region	Name of the Transmission line

1	NR	LILO of 400 KV D/C Lucknow-Bareilly at Sahajahanpur
2	NR	765 kV S/C Sasaram Fatehpur Line -II
3	NR	LILO of both ckt. of 400 KV D/C Kishenpur-Wagoora at Wanpoh
4	NR	LILO of Parbati Pooling Station-Amritsar at Hamirpur
5	NR	400 kV Bhiwani - Jind TL
6	WR	400 kV D/C Raipur-Wardha TL
7	WR	Upgradation of Bina-Agra-Gwalior Ckt- I
8	WR	Upgradation of Bina-Agra-Gwalior Ckt -II
9	NER	LILO of 220kV Misa – Kathalguri Transmission Line at Mariani
10	NER	132/33kV Imphal Substation(New) and LILO of 132kV S/C Ningthoukhong – Yurembam line at Imphal(New) S/S
11	NER	400 kV D/C Balipara - Bongaigaon (Quad) Transmission Line and 30% FSC at Balipara S/S
12	SR	400KV D/C Nellore - Gooty line (Quad)
13	SR	LILO of Simhapuri - Nellore - at nellore Pooling station under ISGS
14	SR	400 kV D/C Vallur-Mallerkotiyar TL
15	WR	1500 MVA 765/400 kV ICT -II at Gwalior
16	WR	1000 MVA 765/400 kV ICT -II at Bina

4.5 Base Cases

4.5.1 An all India load flow base case was prepared for July 2013 conditions. Dispatch summary after arriving at load generation balance for the base case are given below:

Generation Despatch	121 006 MW
Active load, P	117,763 MW
Reactive load, Q	37,792 MVAR
Reactors	11,334 MVAR
Capacitors	17,478 MVAR

4.5.2 Load generation balance and inter-regional flows for the scenario are listed below:

Region-wise Generation and Load demand			Inter-regional Power flows	
Region	**Generation (MW)**	**Load (MW)**	**Inter-regional Corridor**	**Power flow (MW)**
			ER – SR	2505
Northern	34430	40912	WR – ER	451
North Eastern	1757	1512	ER – NR	3522
Western	38121	31791	NER – ER	201
Eastern	19469	13614	WR – NR	2838
Southern	27296 (including wind generation)	29932	WR – SR	895

4.5.3 Base Cases with high import by Northern Region

Total import by NR in base case is 6360 MW. Northern Region (NR) is the main importing region during the monsoon season because of its high agricultural load. Transmission constraints are generally experienced during high import by NR. The focus of studies therefore was to analyse system conditions and constraints with high NR import. Accordingly, variation in base case was considered to arrive at scenarios of higher import by NR. The following four power flow cases were prepared for this purpose:

4.5.4 Case-1: 8200 MW Import by NR

Demand in Northern Region in the base case was scaled up in the ratio of energy shortages reported in July'12 till the total import of NR reached 8200 MW (approx) – Total NR import 8230MW of which 4470 MW through WR (including 1250 through Mundra-Mahendragarh HVDC bipole) and 3760 MW through ER.

4.5.5 Case-2: 9200 MW Import of NR

Northern Region Import was further increased by 1000 MW by taking outage of 2-units at Nathpa Jhakri (230*2) and 2-units at Karcham Wangtoo (225*2) and increasing corresponding generation in Western Region i.e., CGPL Mundra 730 MW) and Adani Mundra (300 MW) – Total NR import 9190 MW of which 5205 through WR (including 1250 through Mundra-Mahendragarh HVDC bipole) and 3985 MW through ER.

4.5.6 Case-3: 10300 MW Import of NR

Total import of Northern Region was further increased to 10300 MW by 1000 MW Load Increase in NR and 1100 MW Load Decrease in WR – Total NR import 10297 MW of which 6046 through WR (including 1250 through Mundra-Mahendragarh HVDC bipole) and 4251 MW through ER.

4.5.7 Case-4: 11300 MW Import of NR

NR import was made 11300 MW by 1000 MW Load Increase in Northern Region and 1100 MW Load reduction in Western Region – Total NR import 11343 MW of which 6807 through WR (including 1250 through Mundra-Mahendragarh HVDC bipole) and 4536 MW through ER.

4.5.8 For analyzing criticalities for the various study cases, maximized dispatch from specific pockets were considered and the LGB arrived at by taking maximum dispatch from one area / generation complex and adjusting the generation in other areas to arrive at overall load generation balance. Generation areas / complexs analyzed for criticality included the following specific packets :

(a) Singrauli/Anpara complex in NR;
(b) Orissa in Eastern Region;
(c) Chattisgarh & Eastern MP generation complex in WR; and
(d) Coastal Gujarat and Mundra in Western Region;

4.5.9 Topology: It may be noted that a few 125 MVAR bus reactors have been commissioned to control high voltage. Howeve,r new 765 kV and 400 kV lines have also been added and the problem of high voltage during light load condition is expected to continue. Therefore, it is expected that a few lines will have to be kept open to control high voltage and the same has accordingly been assumed in the studies.

4.6 **Summary Results of Base Cases** :

4.6.1 Inter-regional flows corresponding to the four base cases of different import scenarios by NR are given in the following table:

S.No.	Inter-regional Corridor	8200 MW Import by NR	9200 MW Import by NR	10300 MW Import by NR	11300 MW Import by NR
1	WR-NR	4470	5205	6046	6807
2	WR-ER	602	840	1136	1452
3	ER-NR	3759	3983	4251	4536
4	ER-SR	2511	2511	2511	2511
5	WR-SR	904	904	904	904
6	NER-ER	202	202	202	202

4.6.2 Summary results of power flow for the above four cases in the critical WR-NR transmission corridor in the West to North direction line-wise are indicated in the Table below.

Sl no	Inter-regional line in WR-NR corridor	Import by Northern Region			
		8200 MW	**9200 MW**	**10300 MW**	**11300 MW**
1	765 kV Gwalior-Agra D/C	2322	2716	3226	3664

2	500 kV Mundra-Mahendargarh Bipole HVDC	1252	1252	1252	1252
3	500kV Vindhyachal BTB HVDC	300	300	300	300
4	400kV Zerda-Bhinmal	271	409	525	639
5	400kV Zerda-Kankroli	200	327	432	535
6	220kV Badod-Modak	70	95	131	167
7	220 kV Badod-Kota	70	95	131	167
8	220 kV Malanpur-Auraiya	-7	5	24	41
9	220 kV Mehagaon-Auraiya	-7	5	24	41
	WR-NR Flow	4471	5204	6045	6806

4.6.3 As would be observed from the above, an incremental increase of 100 MW in demand in Northern Region to be served from source in Western Region leads to 70 MW increase in the West to North corridor with the balance being routed via the West-East-North route. 60% of this incremental flow from West to North gets routed through the 765 kV Bina-Gwalior-Agra route.

4.6.4 The Bina-Gwalior-Agra section is also the first instance in the country where the 765 kV and 220 kV systems are operating in parallel to each other without any 400 kV line in this section. The 220 kV section would not carry much power in normal circumstances; even for a single circuit 765 kV outage. However with both 765 kV circuits out under heavy power flow conditions, the 220 kV section would also trip in cascade. Thus in case the 765 kV Bina-Gwalior D/C line trips, the 220 kV outlets from Gwalior (PG) to Gwalior(MP) needs to be tripped automatically to avoid tripping of 220 kV Bina(MP)-Gwalior(MP) D/C in cascade.

4.6.5 Power flows in inter-regional lines in ER-NR, NER-ER and WR-ER corridors are given in the following table:

S. No	**Inter-regional line in ER-NR Corridor**	**8200 MW Import by NR**	**9200 MW Import by NR**	**10300 MW Import by NR**	**11300 MW Import by NR**
1	400 kV Muzaffarpur-Gorakhpur Ckt-1	437	462	499	539
2	400 kV Muzaffarpur-Gorakhpur Ckt-2	437	462	499	539
3	400 kV Biharshariff-Balia Ckt-1	364	381	404	427
4	400 kV Biharshariff-Balia Ckt-2	364	381	404	427
5	400 kV Patna-Balia Ckt-1	263	279	295	313

6	400 kV Patna-Balia Ckt-2	263	279	295	313
7	400 kV Patna-Balia Ckt-3	297	314	333	353
8	400 kV Patna-Balia Ckt-4	297	314	333	353
9	400 kV Pusauli-Sarnath	272	269	270	269
10	400 kV Pusauli-Allahabad	226	228	228	228
11	765 kV Sasaram-Fatehpur	31	58	85	115
12	765 kV Gaya-Fatehpur	510	556	608	660
	ER-NR Flow	3759	3983	4251	4536

S. No	Inter-regional line in NER-ER Corridor	8200 MW Import by NR	9200 MW Import by NR	10300 MW Import by NR	11300 MW Import by NR
1	220 kV Bongaigaon - Birpara Ckt-1	-7	-7	-7	-7
2	220 kV Bongaigaon - Birpara Ckt-2	-7	-7	-7	-7
3	400 kV Bongaigaon-Binaguri Ckt-1	108	108	108	108
4	400 kV Bongaigaon-Binaguri Ckt-2	108	108	108	108
	NER-ER Flow	202	202	202	202

S. No	Inter-regional line in WR-ER Corridor	8200 MW Import by NR	9200 MW Import by NR	10300 MW Import by NR	11300 MW Import by NR
1	220 kV Korba(E)-Budhipadar Ckt-1	103	112	124	135
2	220 kV Korba(E)- udhipadar Ckt-2	103	112	124	135
3	220 kV Raigarh – Budhipadar	-31	-22	-10	3
4	400 kV Sipat - Ranchi Ckt-1	245	294	353	416
5	400 kV Sipat - Ranchi Ckt-1	245	294	353	416
6	400 kV Raigarh - Rourkela Ckt-1	89	120	160	202
7	400 kV Raigarh - Rourkela Ckt-2	89	120	160	202
8	400 kV Raigarh - Sterlite Ckt-1	-121	-96	-63	-28
9	400 kV Raigarh - Sterlite Ckt-2	-121	-96	-63	-28
	WR-ER Flow	602	840	1136	1452

4.6.6 Power flows in inter-regional lines in ER-SR and WR-SR corridors are given in the following table:

S. No	Inter-regional line in ER-SR and WR-SR Corridor	8200 MW Import by NR	9200 MW Import by NR	10300 MW Import by NR	11300 MW Import by NR
1	500kV Talcher-Kolar HVDC Pole1	954	954	954	954
2	500kV Talcher-Kolar HVDC Pole2	954	954	954	954
3	500 kV Gazuwaka HVDC Pole-1	301	301	301	301
4	500 kV Gazuwaka HVDC Pole-2	301	301	301	301

5	500 kV Bhadrwati Pole-1	452	452	452	452
6	500 kV Bhadrwati Pole-2	452	452	452	452
	Total Import of SR	3415	3415	3415	3415

4.7 Contingency Cases

For assessing the permissible dispatch, all critical outages as apparent to study group based on experience were studied and analysed. High rank contingency cases as obtained from contingency ranking method were also analysed. Contingency Ranking function in PSS/E version 33.2 estimates the severity of designated single branch outage contingencies and ranks them in order of their severity. The severity of a contingency is measured by the Performance Index (PI).

Performance Index Computation

$$PI = \sum_{i=1}^{L} \left(\frac{P_i}{PMAX_i} \right)^2$$

where:

P_i	Is the active power flow on branch i.
$PMAX_i$	Is the rating of branch i.
L	Is the set of monitored branches contributing to PI.

The thermal rating was entered in the above branch ratings. The contingency ranking function was run in the 8200 MW import case of Northern Region and the following top ten contingencies were listed out based on PI ranking:

- Outage of 765 kV Anpara-Unnao (1195 MW)
- Outage of 765 kV Agra-Jhatikara (1411 MW)
- Outage of 765 kV Seoni-Bina (1263 MW)
- Outage of 400 kV Lucknow-Singrauli (396 MW)
- Outage of 765 kV Bhiwani-Jhatikaran (847 MW)
- Outage of 400 kV Singrauli –Fatehpur (446 MW)
- Outage of 765 kV Bina - Gwalior one circuit (1302 MW)
- Outage of 765 kV Bhiwani-Moga (680 MW)
- Outage of 400 kV Anpara-Mau (487 MW)
- Outage of 400 kV Farakka-Jeerat (443 MW)

4.8 Broad conclusions from contingency analysis for the above cases

4.8.1 For the 11300 MW import by Northern Region case, it was observed that the single contingency of outage of one circuit of 765 kV Bina-Gwalior carrying 1950 MW led to the voltage at Gwalior 765 kV dipping to 720 kV from the initial value of 741 kV. The minimum allowable value of 765 kV bus voltage both as per the Indian Electricity Grid Code (IEGC) and the Manual on Transmission Planning Criteria is 728 kV.

4.8.2 For the case 10300 MW import by Northern Region, tripping of 765 kV Agra-Jhatikara S/C line led to loading on the 2 x 1500 MVA, 765/400 kV ICTs at Agra exceeding rated capacity. The loading on Agra ICTs increased further when power flow on Balia-Bhiwadi HVDC bi-pole was reduced. As against its full capacity of 2500MW, power dispatch on Balia-Bhiwadi HVDC link is normally kept around 1200 MW to take care of the line loadings/voltages in the parallel AC network. Therefore the 10300 MW import case was not considered to be fully meeting 'N-1' and 'N-1-1' contingency outage as per planning criteria.

4.8.3 For 9200 MW import by Northern Region, all contingency cases were seen OK. As such this case was found to be fully meeting 'N-1' and "N-1-1' contingency outage as per planning criteria.

4.9 **Case for 9750 MW Import by NR** :

4.9.1 In order to find out maximum sustainable import by Northern Region, the import of NR was gradually enhanced from 9200 MW. It was observed that import by the Northern region can be maximised to 9750 MW (new Case no 2A), at which the 765/400 kV ICTs at Agra get loaded to their full capacity. The load generation balance corresponding to the 9750 MW import case for different control areas is enclosed at Annexe-IV. The contingency ranking function was run in the 9750 MW import case of Northern Region and the following top ten contingencies were listed out based on PI ranking:

- Outage of 765 kV Anpara-Unnao (1209 MW)
- Outage of 765 kV Agra-Jhatikara (1699 MW)
- Outage of 765 kV Seoni-Bina (1444 MW)
- Outage of 765 kV Jhatikaran- Bhiwani (988 MW)
- Outage of 400 kV Singrauli- Lucknow (400 MW)

- Outage of 765 kV Bina - Gwalior one circuit (1559 MW)
- Outage of 765 kV Bhiwani-Moga (742 MW)
- Outage of 400 kV Singrauli –Fatehpur (444 MW)
- Outage of 400 kV Anpara-Mau (474 MW)
- Outage of 400 kV Adani-Sami (482 MW)

4.9.2 Power flows in inter-regional lines in WR-NR and ER-NR corridors for the 9750 MW case are given in the following table:

Inter-regional line in WR-NR corridor			**Inter-regional line in ER-NR Corridor**		
Transmission Line		**Flow (MW)**	**Transmission Line**		**Flow (MW)**
1	765kV Gwalior-Agra D/C	3052	1	400kV Muzaffarpur-Gorakhpur Ckt-1	498
2	500kV Mundra-Mahendargarh HVDC Bipole	1252	2	400kV Muzaffarpur-Gorakhpur Ckt-2	498
3	500kV Vindhyachal HVDC back-to-back	250	3	400kV Biharshariff-Balia Ckt-1	328
4	400kV Zerda-Bhinmal	494	4	400kV Biharshariff-Balia Ckt-2	328
5	400kV Zerda-Kankroli	404	5	400kV Patna-Balia Ckt-1	256
6	220kV Badod-Modak	122	6	400kV Patna-Balia Ckt-2	256
7	220kV Badod-Kota	122	7	400kV Patna-Balia Ckt-3	289
8	220kV Malanpur-Auraiya	13	8	400kV Patna-Balia Ckt-4	289
9	220kV Mehagaon-Auraiya	13	9	400kV Pusauli-Sarnath	250
	WR-NR Flow	**5722**	10	400kV Pusauli-Allahabad	247
			11	765kV Sasaram-Fatehpur	156
			12	765 kV Gaya-Fatehpur	644
				ER-NR Flow	**4039**

4.9.3 Based on above, 9750 MW import by Northern Region case was considered to be fully meeting 'N-1' and "N-1-1" contingency outage as per planning criteria.. Load generation balance and inter-regional flows for the 9750 MW import by NR case are listed below :

Region-wise Generation and Load demand			**Inter-regional Power flows**	
Region	**Generation (MW)**	**Load (MW)**	**Inter-regional Corridor**	**Power flow (MW)**
			ER – SR	2511
Northern	33580	41967	WR – ER	911
North Eastern	1757	1512	ER – NR	4040
Western	40124	31673	NER – ER	202
Eastern	19469	13615	WR – NR	5721
Southern	27296 (including wind generation)	29932	WR – SR	904

4.9.4 State-wise Load and generation for the 9750 MW import by Northern Region case are listed below :

Region / State	**Load (MW)**	**Generation (MW)**	**Region / State**	**Load (MW)**	**Generation (MW)**

Northern Region			**Eastern Region**		
Punjab	8968	2941	West Bengal	5284	3735
Haryana	6497	2212	Jharkhand	1029	367
Rajasthan	6298	3320	Orissa	2877	1625
Delhi	4851	835	Bihar	1853	139
Uttar Pradesh	11186	5317	DVC	2512	4373
Jammu & Kashmir	1103	641	Sikkim	60	0
Uttarakhand	1452	648	ISGS/IPP	0	9260
Himachal Pradesh	975	628	Total ER	**13615**	**19499**
ISGS/IPP	636	17037			
Total NR	**41967**	**33580**	**North-eastern Region**		
Western Region			Manipur	87	0
Chhattisgarh	2421	1869	Meghalaya	214	54
Madhya Pradesh	5246	1961	Mizoram	53	0
Maharashtra	12824	8003	Nagaland	74	0
Gujarat	11182	8628	Assam	839	186
ISGS /IPP	0	19663	Tripura	153	80
Total WR	**31673**	**40124**	Arunachal Pradesh	93	0
Southern Region			ISGS/IPP	0	1437
Andhra Pradesh	9183	6695	Total NER	**1512**	**1757**
Tamil Nadu	11527	7573			
Karnataka	7121	5232			
Kerala	2101	617			
ISGS/IPP	0	7180			
Total SR	**29932**	**27296**			

4.9.5 Dispatches for ISGS and IPPs generation plants for the 9750 MW import by NR case are listed below :

GENERATION PLANT	Dispatch (MW)	**GENERATION PLANT**	Dispatch (MW)	**GENERATION PLANT**	Dispatch (MW)
Northern Region		**Western Region**		**Eastern Region**	
SEWA-II	30	PENCH	74	FARAKKA	1208
SALAL	661	EMCO	253	KAHALGAON	1830
NIMOO	11	APL-GONDA	555	TALA	1020
CHUTAK	11	VADINAR	449	TEESTA	510
DHAULIGANGA	269	MAHAN	509	RANGEET	60
CHAMERA	510	BINA POWER	210	TALCHER Stg-I	940
CHAMERA-2	270	VSTPP EXT	407	TALCHER Stg-II	1568
DULHASTI	96	KORBA STPS	2451	ADHUNIK	240
URI	480	VINDHYACHAL	2681	CHUKKA	300
KOTESHWAR	163	PATHADI	559	GMR	561
TEHRI	240	NSPCL	450	STERLITE	901
NATHPA JHAKRI	920	JINDAL	1000	TEESTA III	120
SIUL2	45	ACBL	231	**TOTAL ER**	**9260**
JHAJJAR	900	SIPAT	2560		

RAPP2	267	TARAPUR2	401		
RAPPBG	392	MAUDA	420	**NE Region**	
NAPP	392	TAPP4	832	LOKTAK	67
TANDA	392	DHABOL	500	KHANDONG	48
BTPP	627	GNTPC	240	KOPILI	125
FARIDABAD	384	KAWAS	176	KATHALGURI	175
AURYA	394	KAPP	407	RANGNADI	391
ANTA	374	CGPL MUNDRA	3800	PALLATANA	580
DADRI	460	TORRENT	245	**TOTAL NER**	**1437**
UNCHAHAR	1021	BALCO	255		
SINGRAULI	1851	**TOTAL WR**	**19663**		
DADRI	920				
RIHAND	2225				
CHAMERA-III	210	**Southern Region**			
KARCHAM WANGTOO	450	RAMAGUNDAM	1610		
DADRI THERMAL	706	NLC	1768		
TANAKPUR	23	MAPS	313		
BHAKRAL6	211	KAIGA	600		
BHAKRAL2	211	SIMHADRI	900		
BHAKRA RB	242	VALLUR	430		
DEHAR2	301	KUDANKULAM	800		
DEHAR4	272	MEPL	136		
GANGUWAL	19	SEPL	273		
PONG	89	LANCO	350		
TOTAL NR	**17037**	**TOTAL SR**	**7180**		

4.10 **Stability studies** both under N-1 and N-1-1 scenario were performed for the following contingencies.

1) Three phase to ground fault on 765 kV Bina-Gwalior-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Zerda-Kankroli line 10 seconds later, which is cleared by a three phase trip.

2) Three phase to ground fault on 765 kV Seoni-Bina line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Seoni-Khandwa line 10 seconds later, which is cleared by a three phase trip.

3) Three phase to ground fault on 765 kV Agra-Jhatikara line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Agra(PG)-Agra(UP)-1 line 10 seconds later, which is cleared by a three phase trip.

4) Three phase to ground fault on 765 kV Anpara-Unnao line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Anpara-Sarnath-1 line 10 seconds later, which is cleared by a three phase trip.

5) Three phase to ground fault on 765 kV Gaya-Fatehpur line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Muzaffarpur-Gorakhpur-1 line 10 seconds later, which is cleared by a three phase trip.

6) Three phase to ground fault on 400 kV CGPL Mundra-Bachau-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV CGPL Mundra-Bachau-2 line 10 seconds later, which is cleared by a three phase trip.

7) Three phase to ground fault on 400 kV Jhakri-Panchkula-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Karcham-Abdullapur-1 line 10 seconds later, which is cleared by a three phase trip.

8) Three phase to ground fault on 765 kV Bilaspur-Seoni-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Bhilai-Seoni line 10 seconds later, which is cleared by a three phase trip.

Stability analysis plots for all the above contingencies under the case of **9750 MW import by Northern Region** (Case- 2A) are enclosed as **Appendix 4.1** at the end of this chapter. From these, it is concluded that 9750 MW import by NR case fully meets ‘N-1’ as well as ‘N-1-1’ contingency outages as per planning criteria.

It may be noted that the simulations done did not indicate any problem of small signal stability. However, in actual operation, ,POSOCO has reported that as detected through Phasor Measurement Units(PMUs), both inter-area as well as local modes of oscillation are experienced at times which get damped out in most of the cases. Worldwide, large power systems have experienced small signal stability problems which have in some cases led to a disturbance. Presence of oscillations with a few modes having negative damping is a matter of concern in the Indian grid also and this aspect needs to be monitored closely and studied further. To improve small signal stability of the system, all the upcoming new generators have to ensure that properly tuned PSS is commissioned before COD of the units and with regards to existing units, the PSS re-tuning may be required based on need as seen from the WAMS/PMU data and advised by the system operators - SLDC/RLDC. Validation/ re-tuning of all controllers needs to be done once every three years and a certificate should be submitted to the concerned RLDC/RPC.

4.11 **Timely clearance of fault** has been an issue in several instances in the past and NLDC, in its feedback to CEA and CTU, has reported several instances of multiple element outages. These occur mainly due to mal-operation of protective systems. It is not possible to plan the transmission system for such multiple element outages. However, in order to simulate this scenario, the second fault (single phase to ground) duration (N-1-1 scenario) was kept at 500 msec corresponding to the Zone-2 timings. It was observed that for all the cases above, the system was stable except in S no 6 where the system was unstable. The stability plots for this unstable case are enclosed as case-9 of Appendix 4.1 given at end of this chapter. This suggests that for Mundra UMPP of CGPL under full generation conditions, a System Protection Scheme (SPS) for automatic reduction of generation in case of 'N-1-1' contingency is necessary.

4.12 **Operation of Mundra – Mahendragarh HVDC link :** The Mundra-Mahendragarh HVDC line is a tie line of Mundra Adani Power Project. In the system simulation studies corresponding to July 2013 conditions, the power flow on the ± 500 kV, 2500 MW HVDC bi-pole line from Mundra-Adani to Mahendragarh in Haryana, the power order on the HVDC was kept limited to 1250 MW as per operational practice at the time of studies. Factoring its 20% overload capability, power order on the link has since been increased to 1500MW. Power flow on this HVDC link can be further increased taking advantage of SPS installed at APL Mundra. The Task Force would suggest that capability of the Mundra - Mahendragarh HVDC line to be optimally utilized. Increase in power transfer through Mundra-Mahendragarh HVDC link will result in further increase in maximum safe import by Northern Region and would also be helpful contingency of outage on any NR – WR inter-regional line.

4.13 **Other special dispatch scenarios in case 2A**

In the above Case 2A, scenarios of **(a)** increasing 1000 MW generation in Eastern Region (DVC and West Bengal system) in lieu of W3 zone; and **(b)** full generation at Singrauli/Rihand/Anpara complex; were also studied to examine whether any new constraints show up.

In studies for scenario **(a)** above, it was observed that the W3 Chhattisgarh zone generation in Case 2A was 8650 MW (for all regional entities). This was increased by 1100 MW with corresponding reduction in generation in CGPL Mundra, Gujarat and Maharashtra. No constraint was observed. Further increase in W3 generation from the level of 9750 MW could also be possible if generation is reduced in pockets other than W3 zone in Western region and/or further load increase takes place within Western Region. However, in the absence of any such change (which is most probable also, as per the expected load generation scenario), if this increase in generation in W3 is accompanied by an increase in load in Northern Region, the West to North inter-regional constraint will arise. Hence during the month of July 2013, any constraint in W3 would be governed mainly by the constraints in West to North corridor limits. During other period such as say the October-May period when Western region load is high, the studies for W3 zone would have to be done, which in any case is a continuous process as stated earlier.

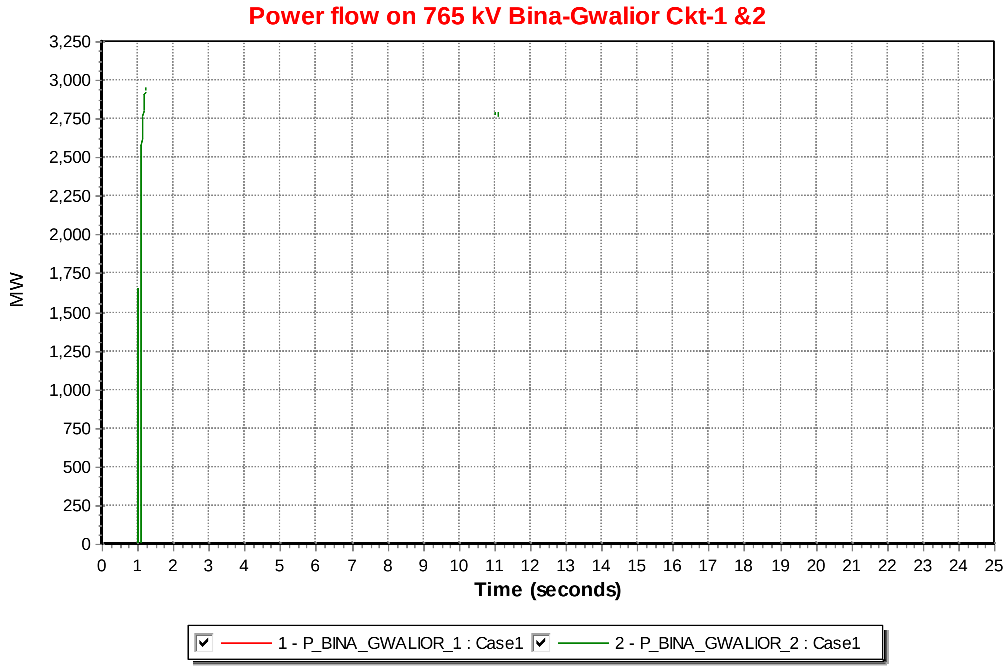
In studies for scenario **(b)** above, with full generation at Singrauli/Rihand/Anpara complex (6600 MW), there was no problem of stability; however loading on 400 kV Anpara-Obra section was quite high and under N-1 contingency, it crosses thermal limit. This is mainly on account of low despatch at Obra TPS of the order of 450 MW.

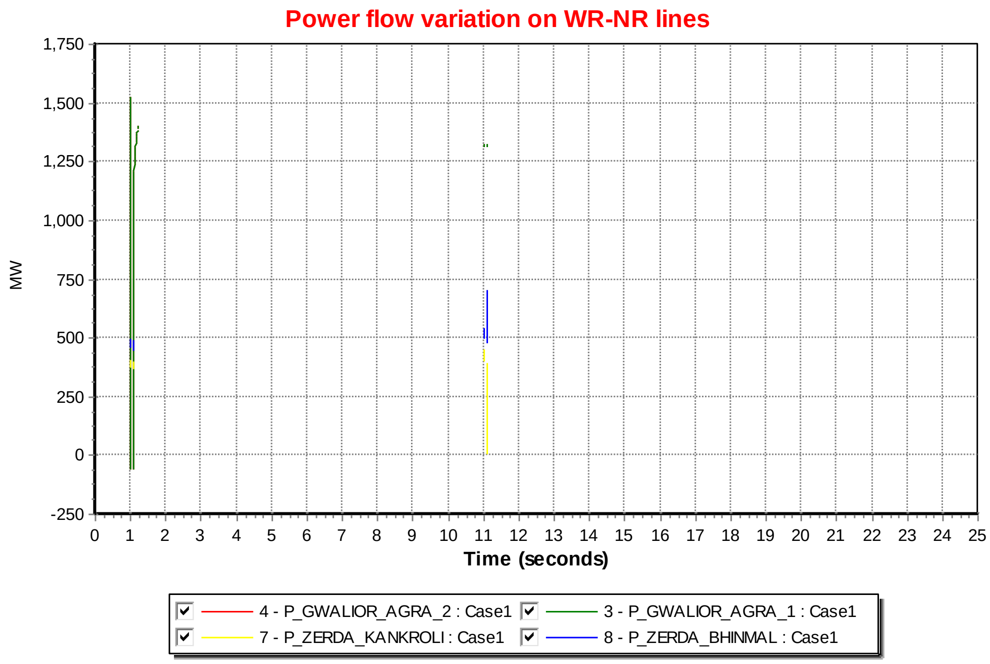
4.14 **Addressing Short Circuit Levels through Bus-Splitting**: Increase in short circuit levels due to the expansion of the power system has led to a decision in the planning horizon to split the 400 kV buses at several places. In actual operation these have not yet been implemented. In case the splitting of buses at all these 400 kV buses envisaged in the planning horizon are implemented it would lead to a reduction in reliability. In all the simulations performed for these studies, interconnected system has been considered without bus splitting. Operational studies need to be updated factoring the planned bus-splitting when studies are carried out for the post bus-splitting conditions. implementation.

Appendix 4.1

Stability Plots Case-1, Page-1/3

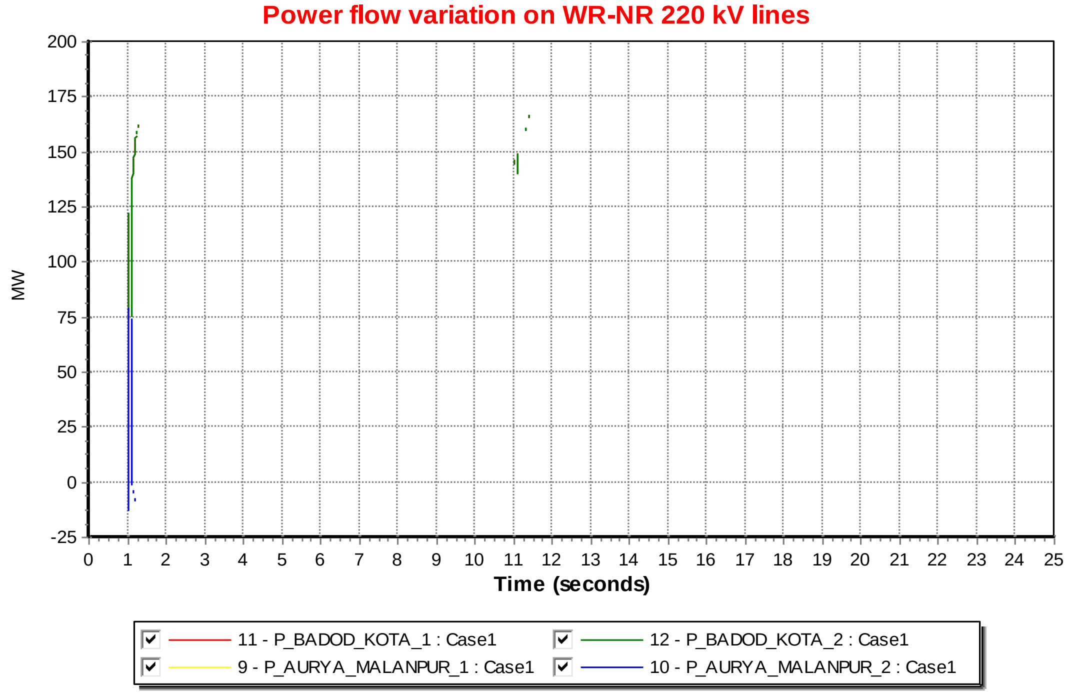
Case-1: Three phase to ground fault on 765 kV Bina-Gwalior-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Zerda-Kankroli line 10 seconds later which is cleared in 100ms by a three phase trip.

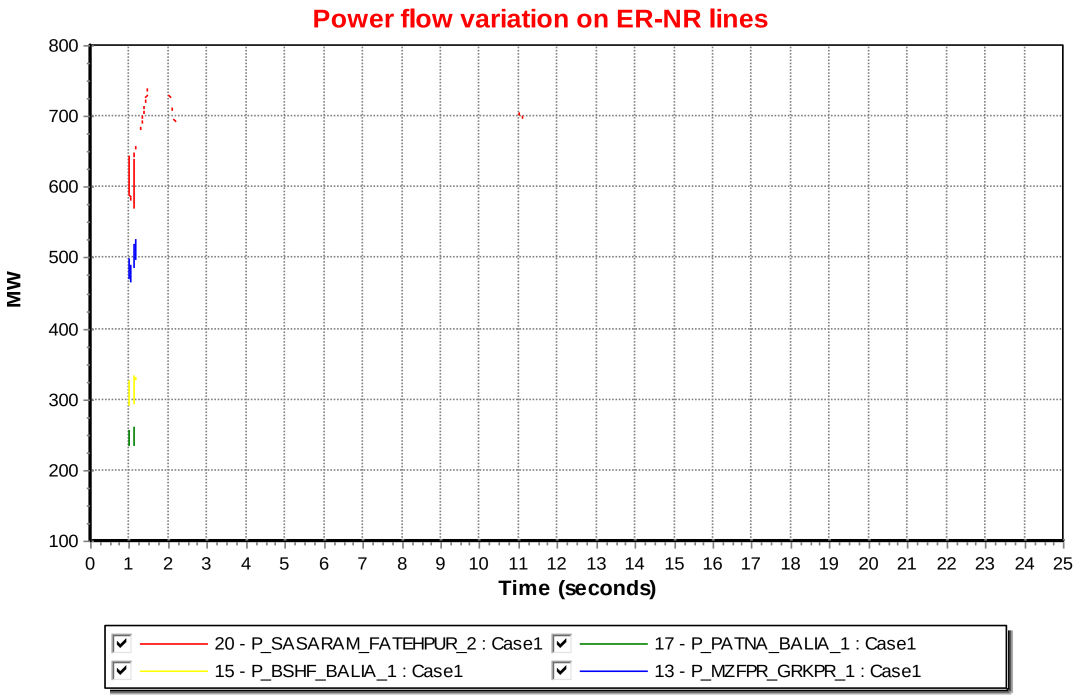




Appendix 4.1
(Page 2/20 of Appendix)

Stability Plots Case-1, Page-2/3

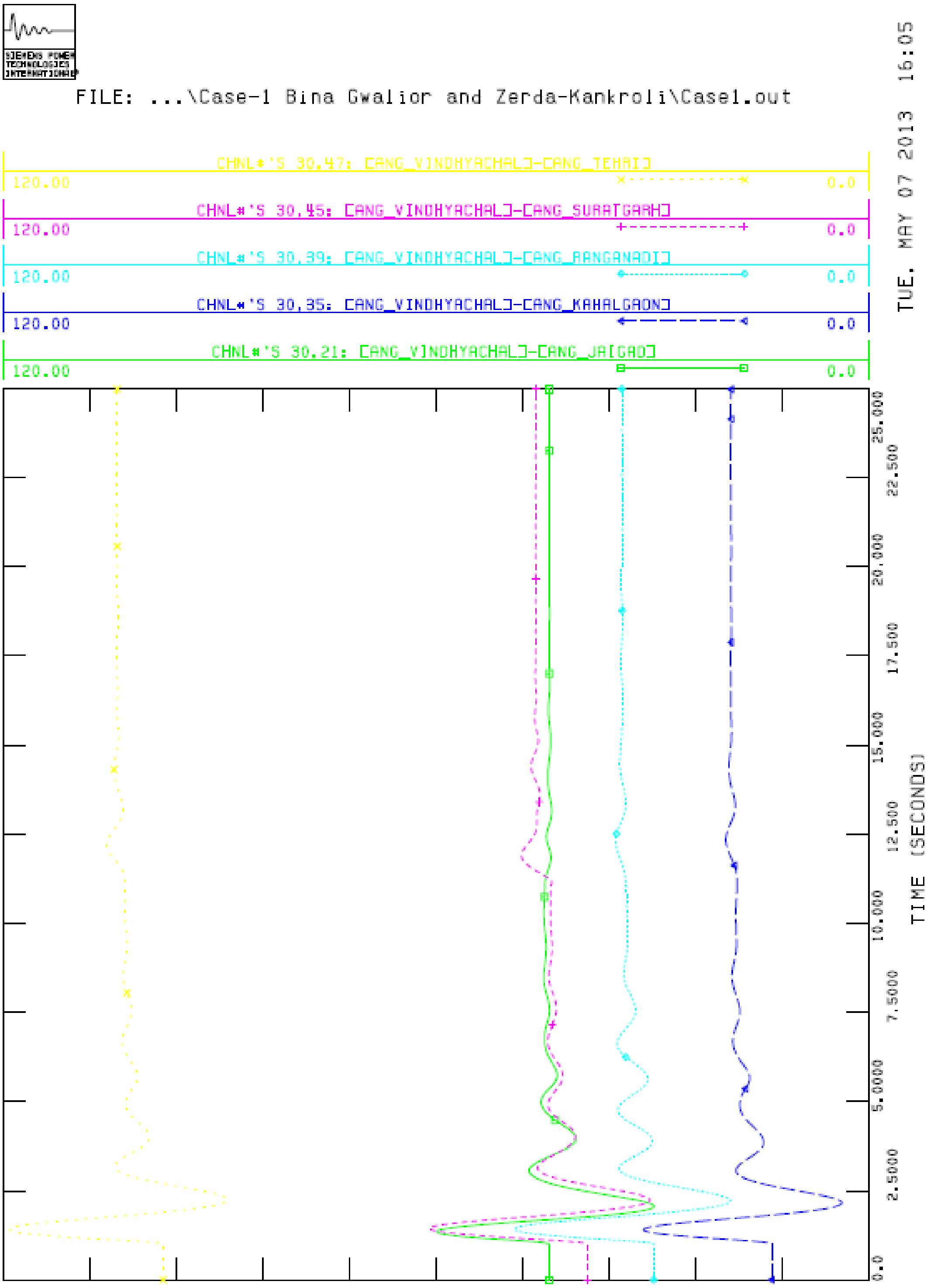




Appendix 4.1

(Page 3/20 of Appendix)

Stability Plots Case-1, Page-3/3

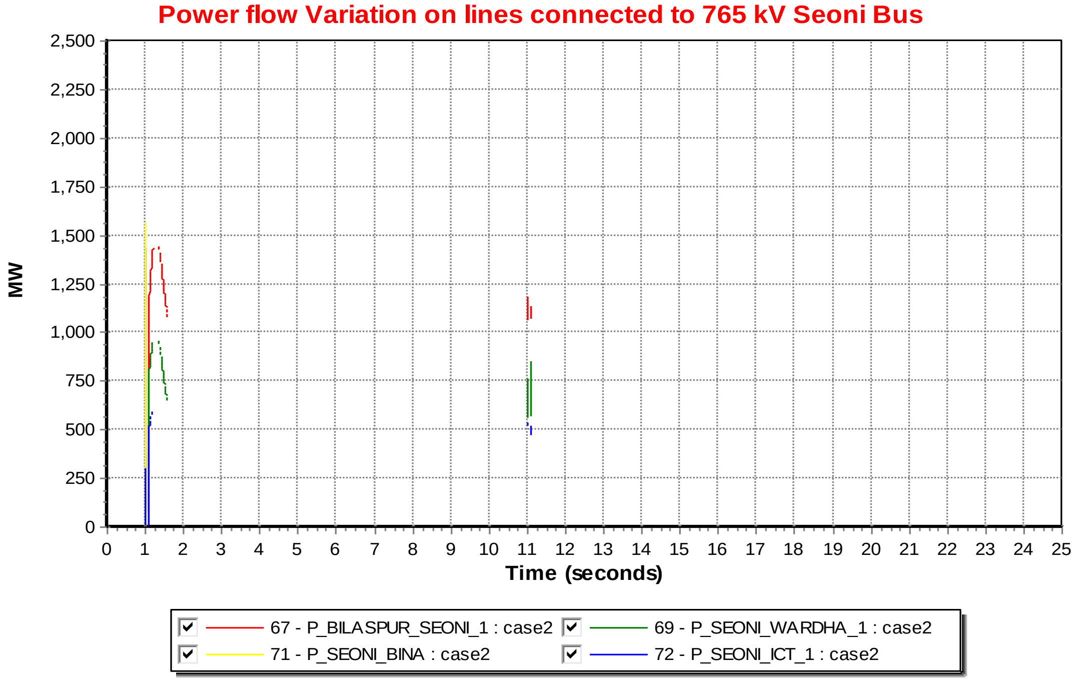


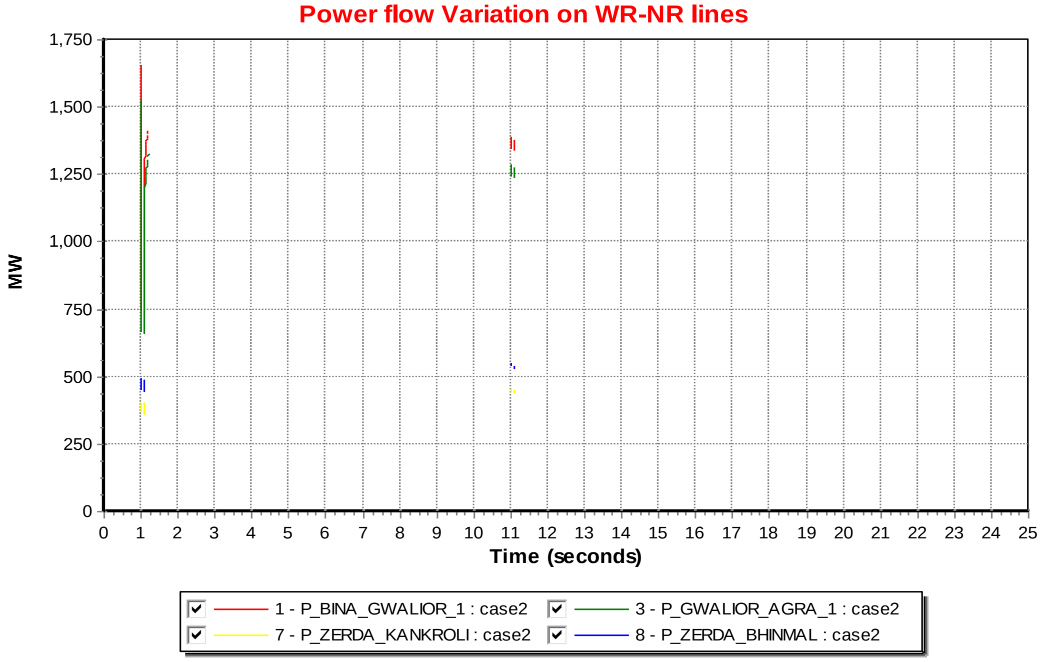
Appendix 4.1

Stability Plots Case-2, Page-1/2

(Page 4/20 of Appendix)

Case-2: Three phase to ground fault on 765 kV Seoni-Bina line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Seoni-Khandwa line 10 seconds later which is cleared in 100ms by a three phase trip.

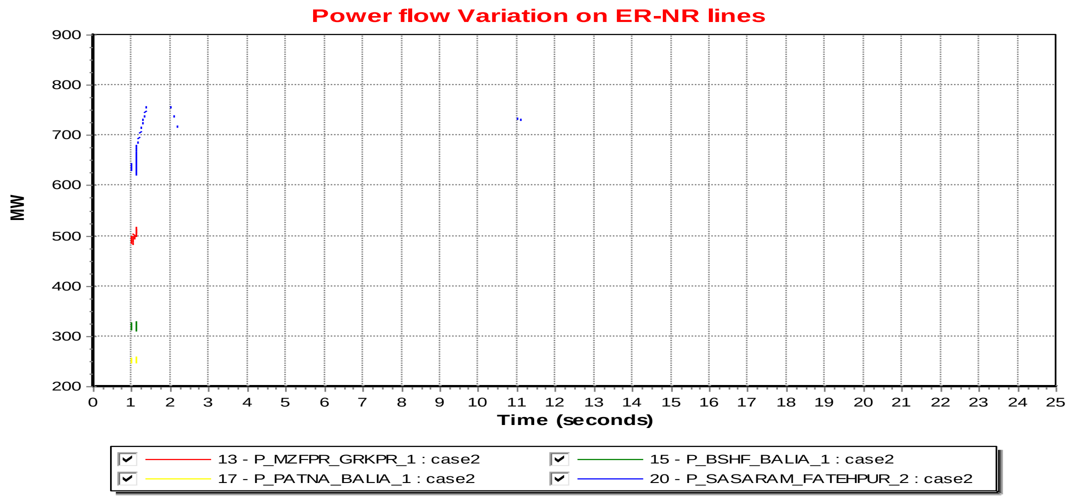


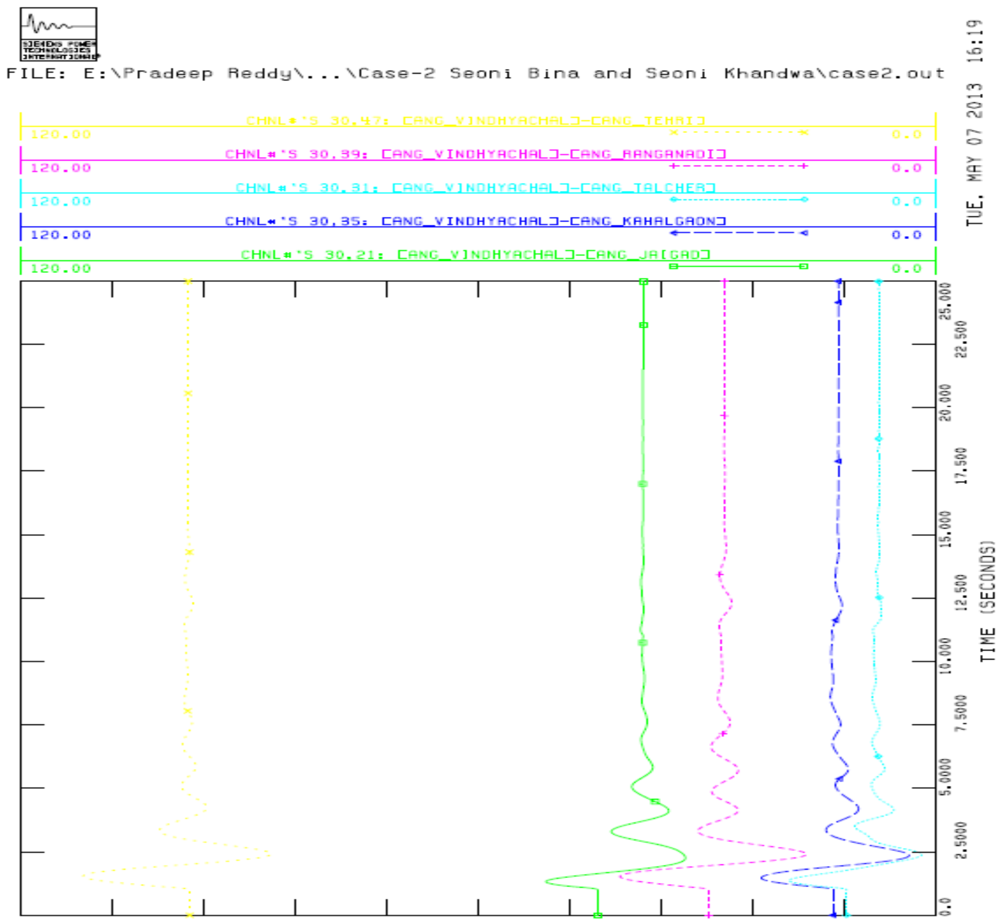


Appendix 4.1

(Page 5/20 of Appendix)

Stability Plots Case-2, Page-2/2



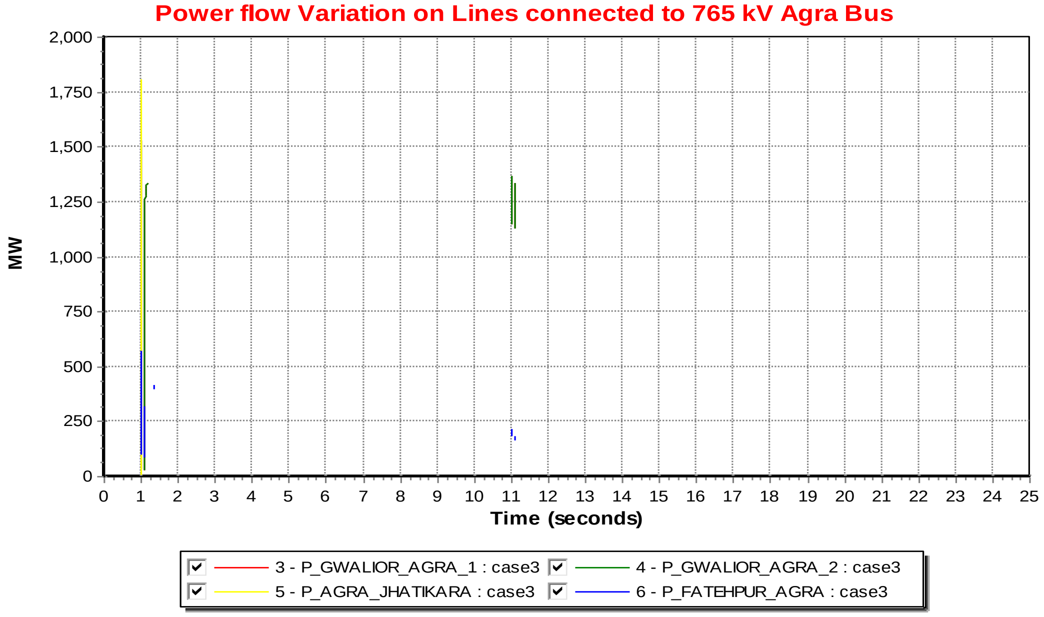


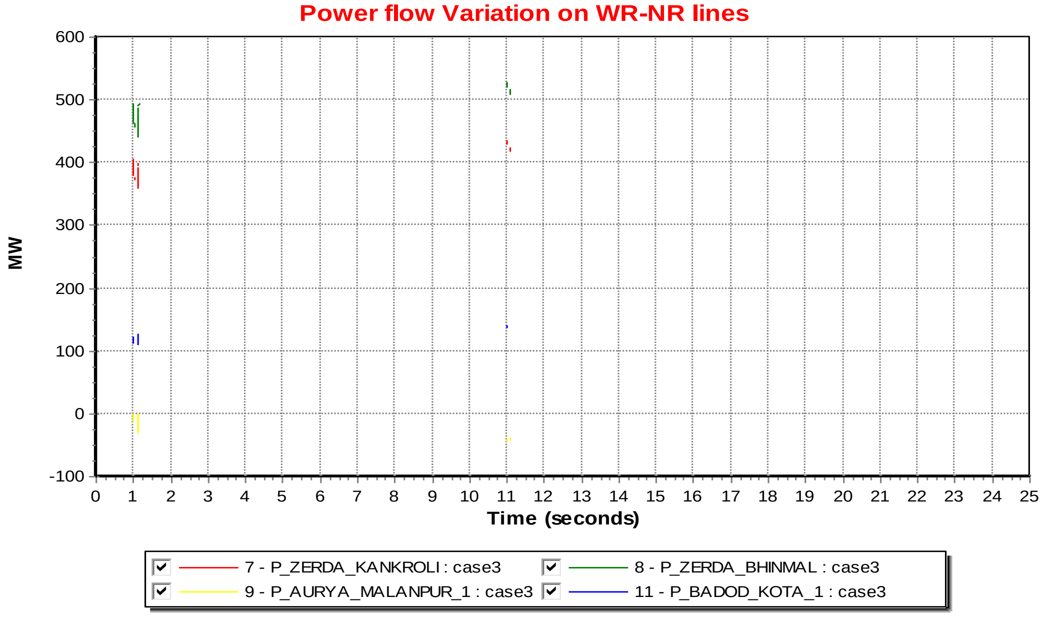
Appendix 4.1

Stability Plots Case-3, Page-1/3

(Page 6/20 of Appendix)

Case-3: Three phase to ground fault on 765 kV Agra-Jhatikara line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Agra(PG_-Agra(UP)-1 line 10 seconds later which is cleared in 100ms by a three phase trip.





Appendix 4.1

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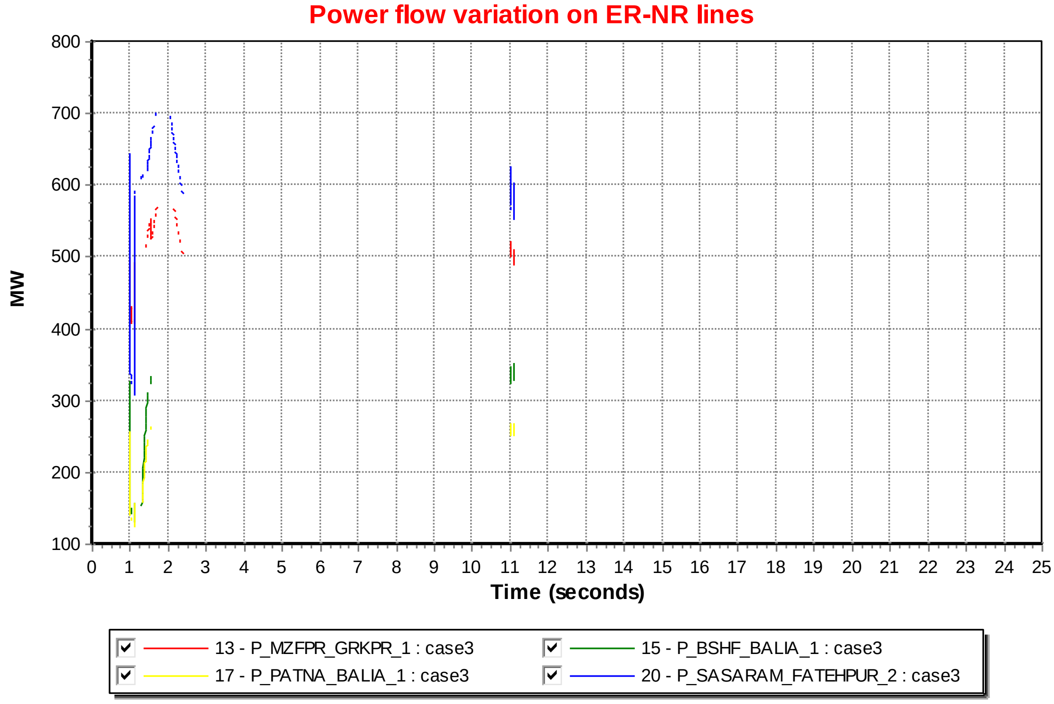
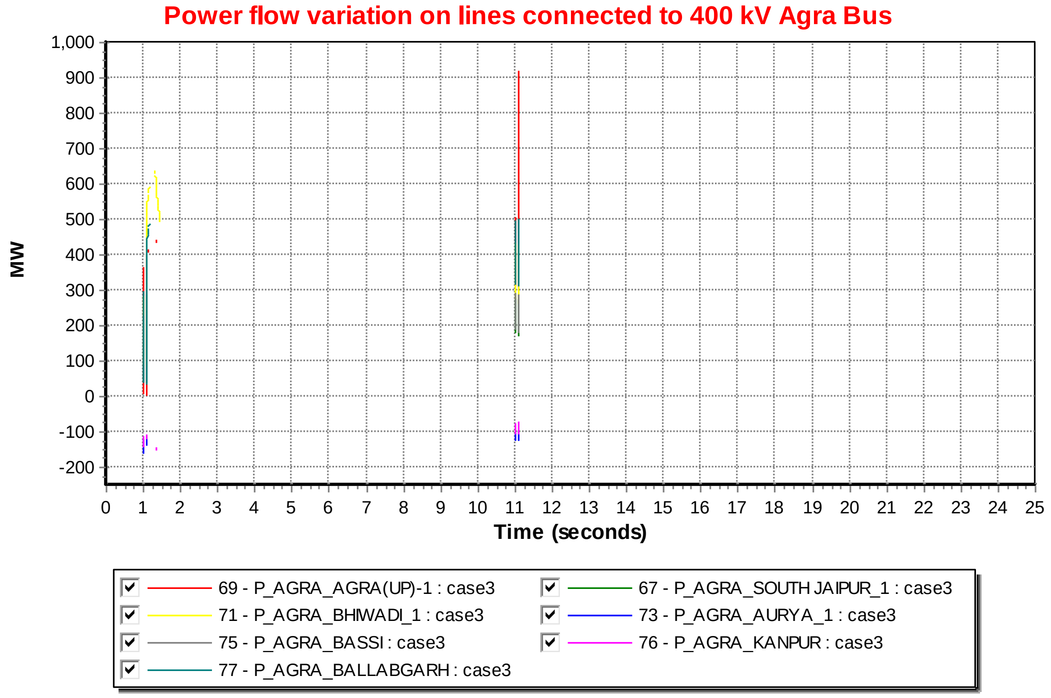
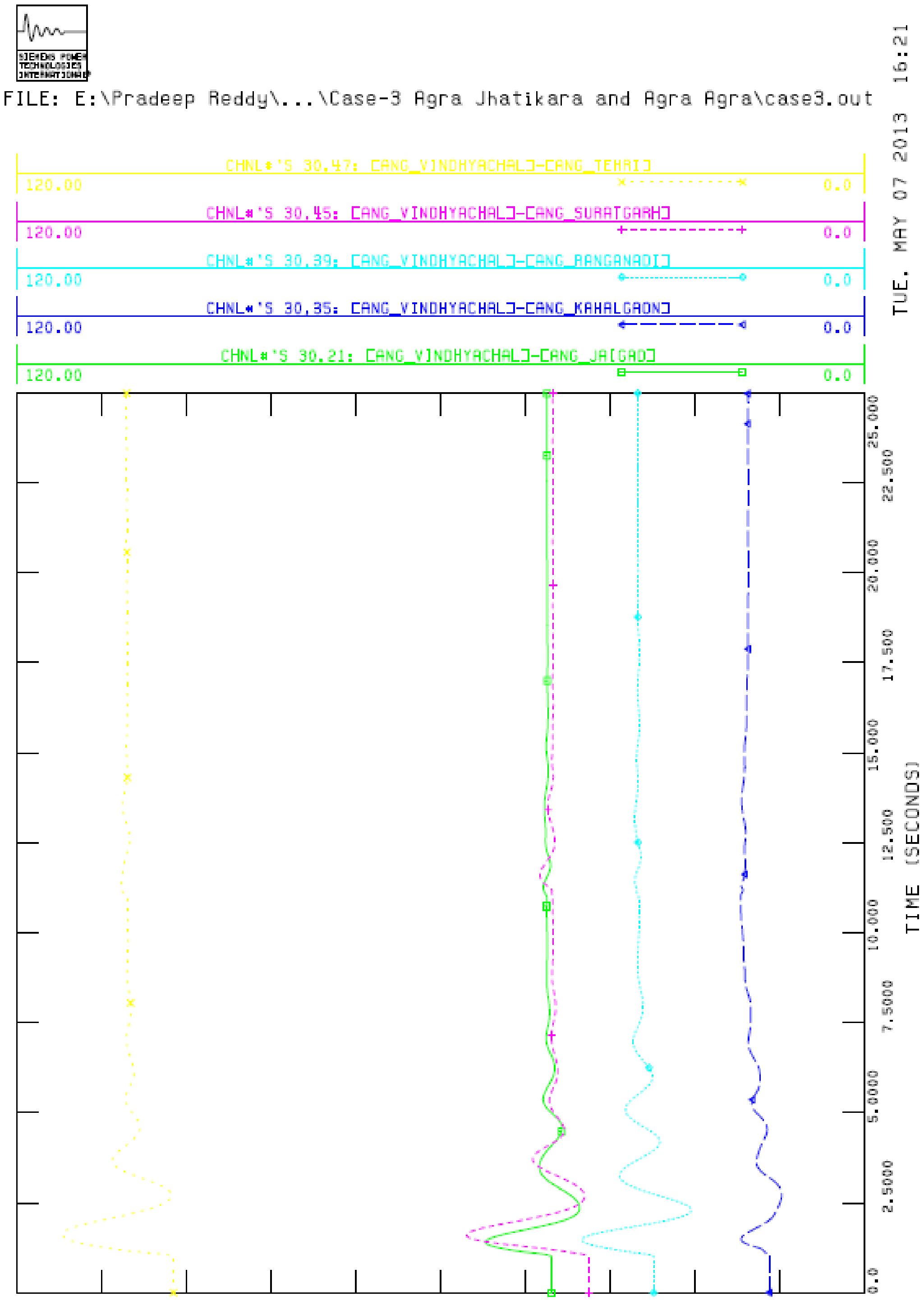
Stability Plots Case-3, Page-2/3





Appendix 4.1
(Page 8/20 of Appendix)

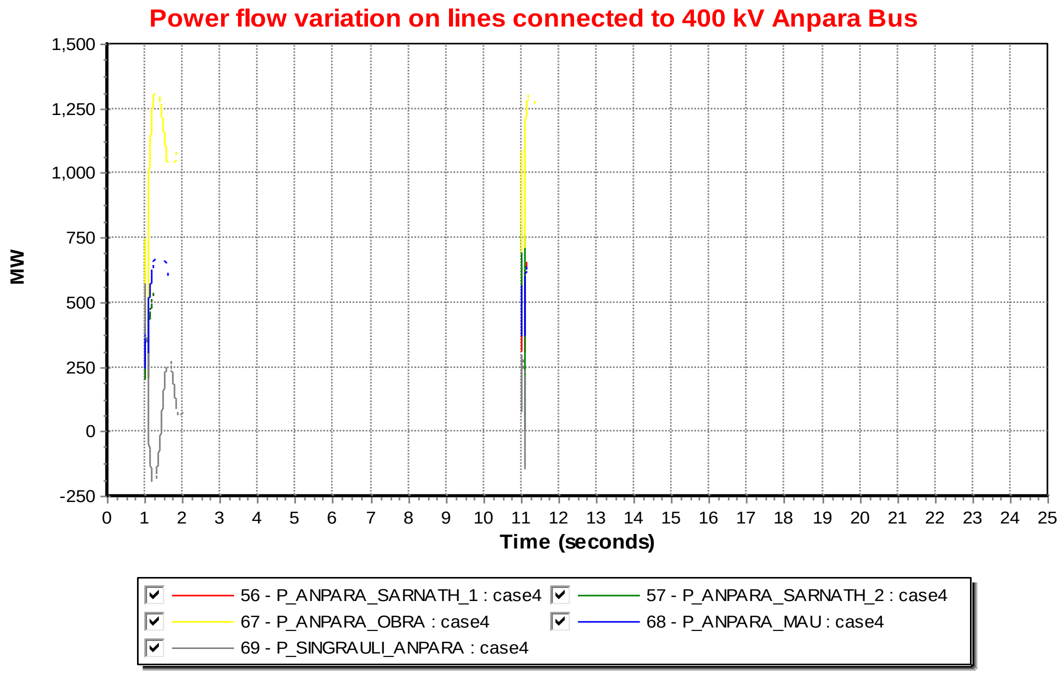
Stability Plots Case-3, Page-3/3

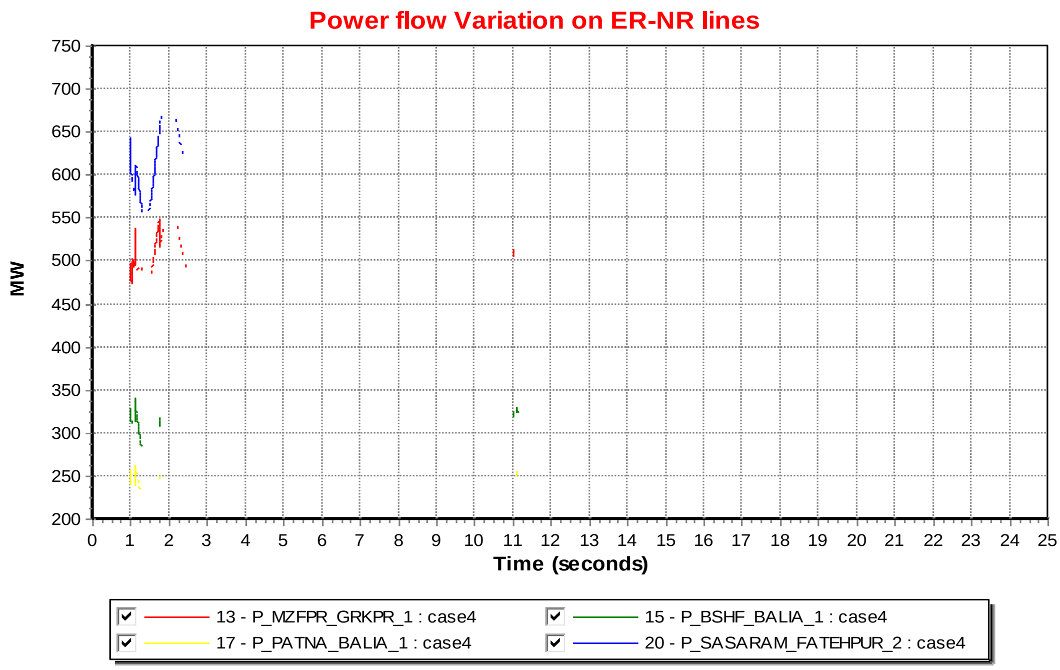


Appendix 4.1
(Page 9/20 of Appendix)

Stability Plots Case-4, Page-1/2

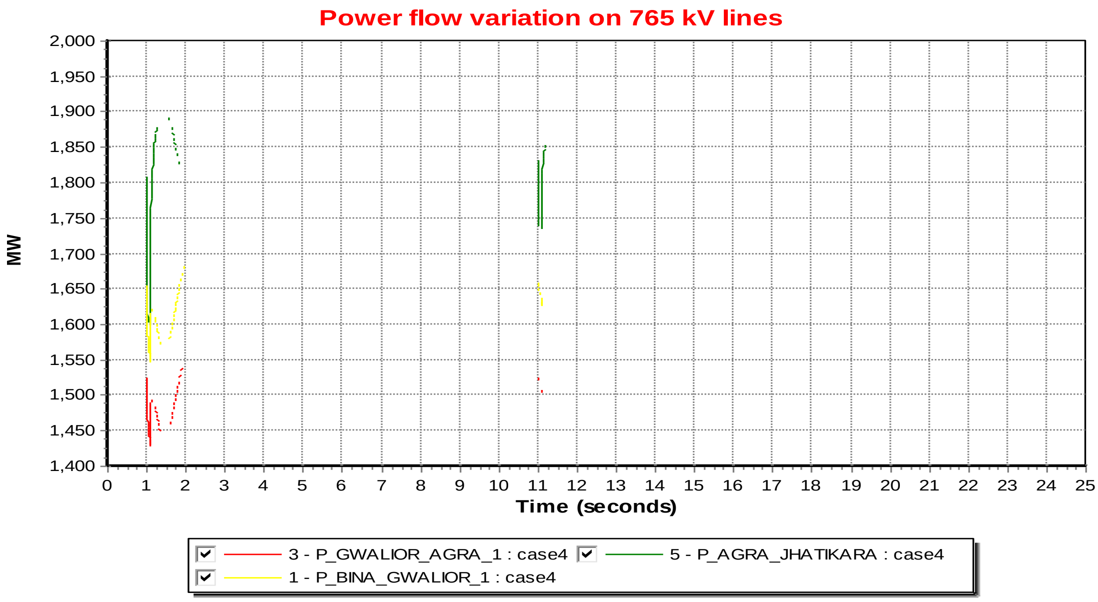
Case-4: Three phase to ground fault on 765 kV Anpara-Unnao line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Anpara-Sarnath-1 line 10 seconds later which is cleared in 100ms by a three phase trip.

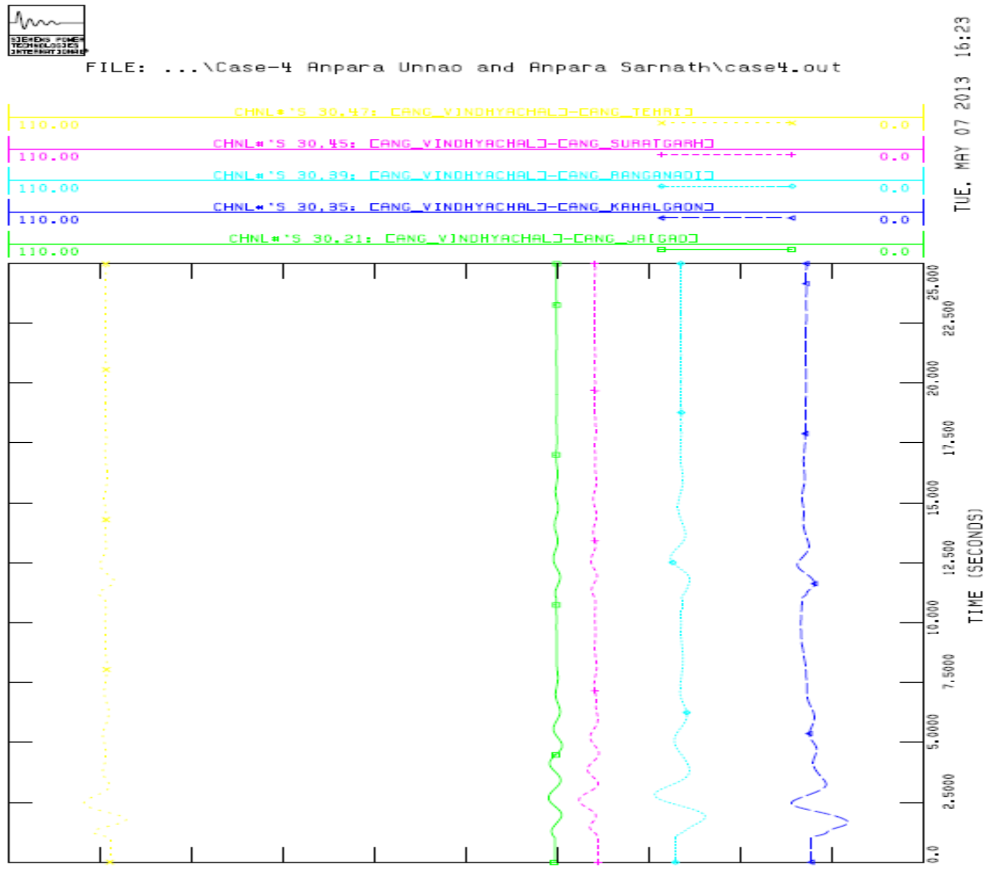




Appendix 4.1
(Page 10/20 of Appendix)

Stability Plots Case-4, Page-2/2



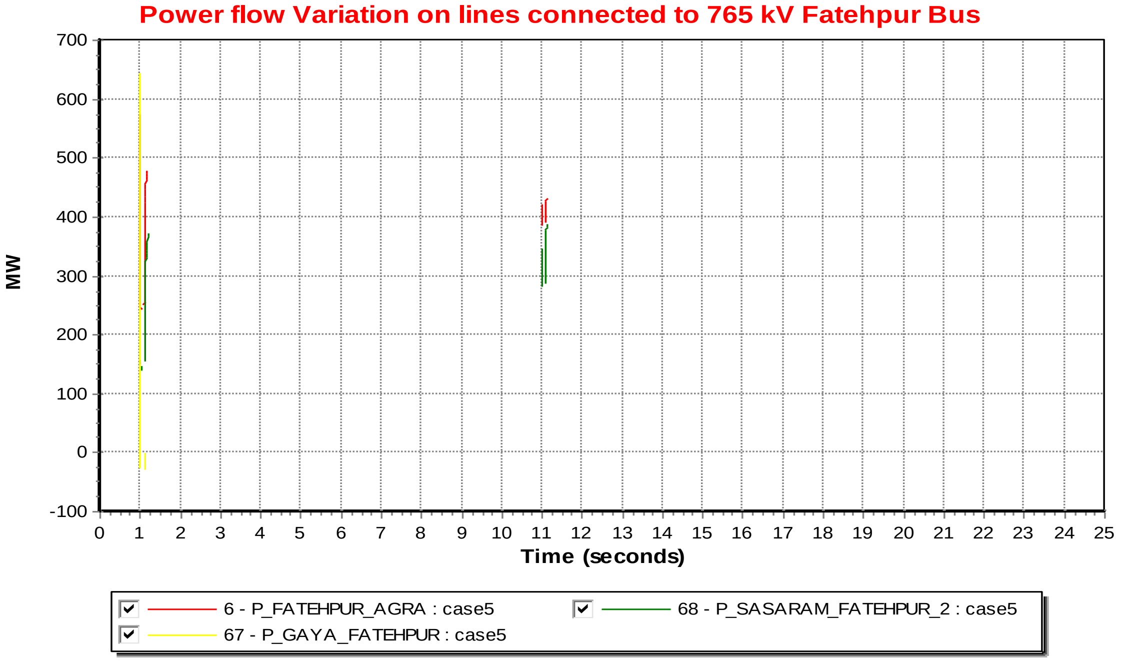


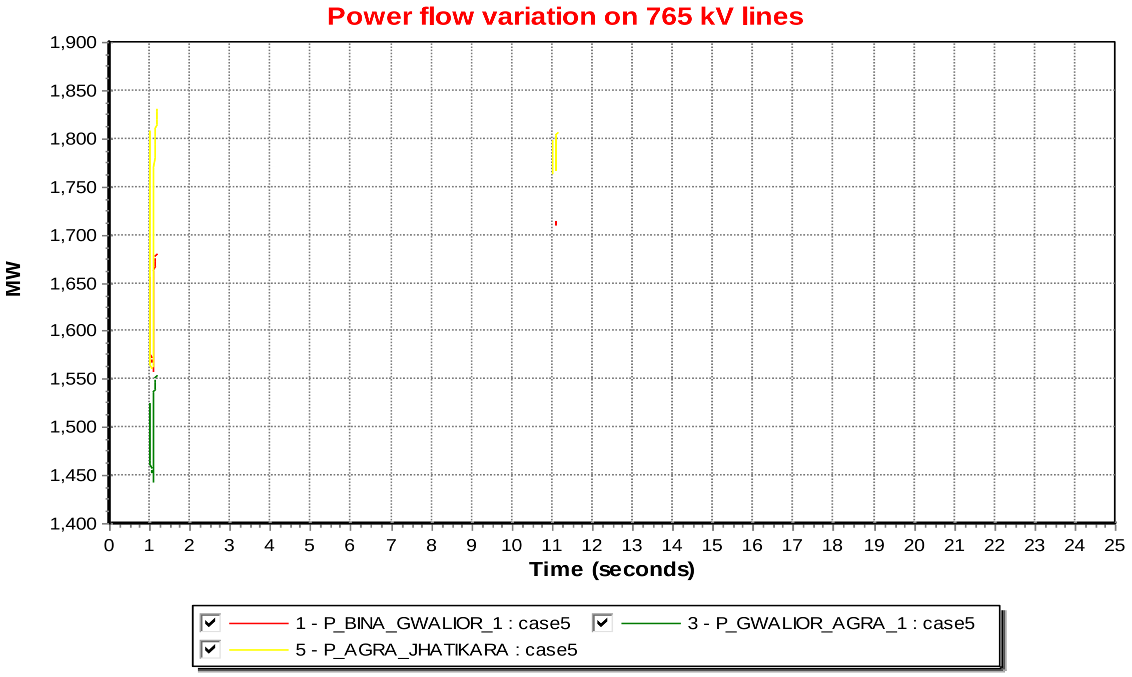
Appendix 4.1

Stability Plots Case-5, Page-1/2

(Page 11/20 of Appendix)

Case-5: Three phase to ground fault on 765 kV Gaya-Fatehpur line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Muzaffarpur-Gorakhpur-1 line 10 seconds later which is cleared in 100ms by a three phase trip.





Appendix 4.1

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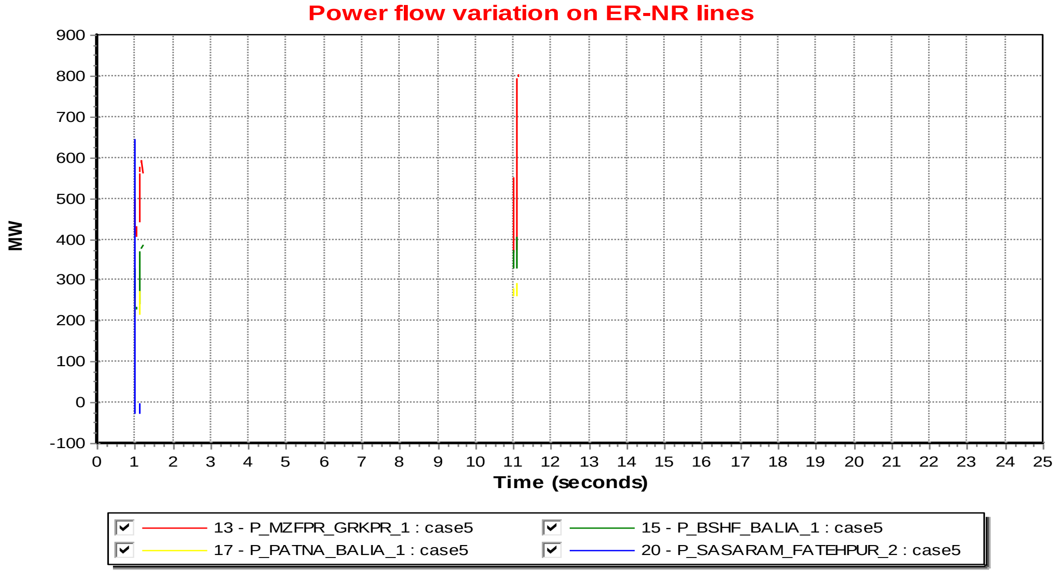
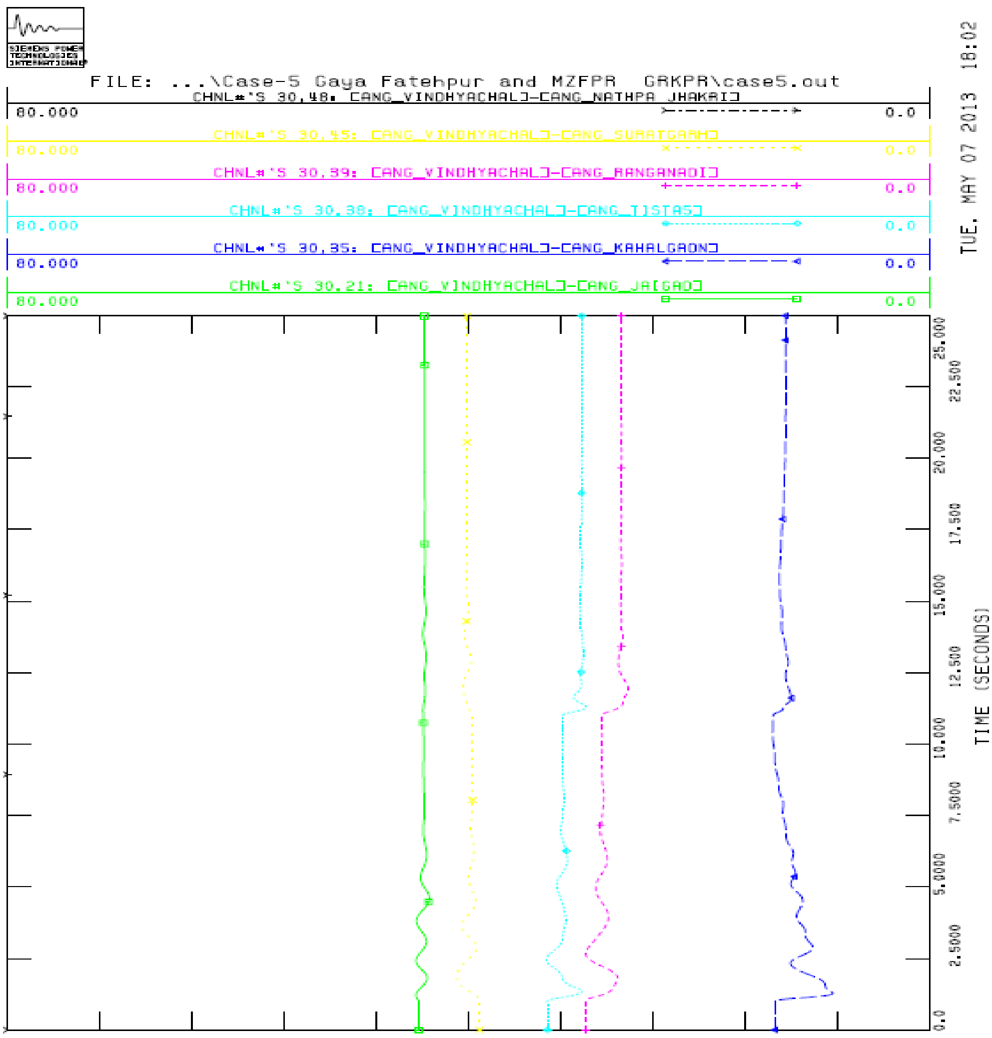
Stability Plots Case-5, Page-2/2





Appendix 4.1

Stability Plots Case-6, Page-1/3

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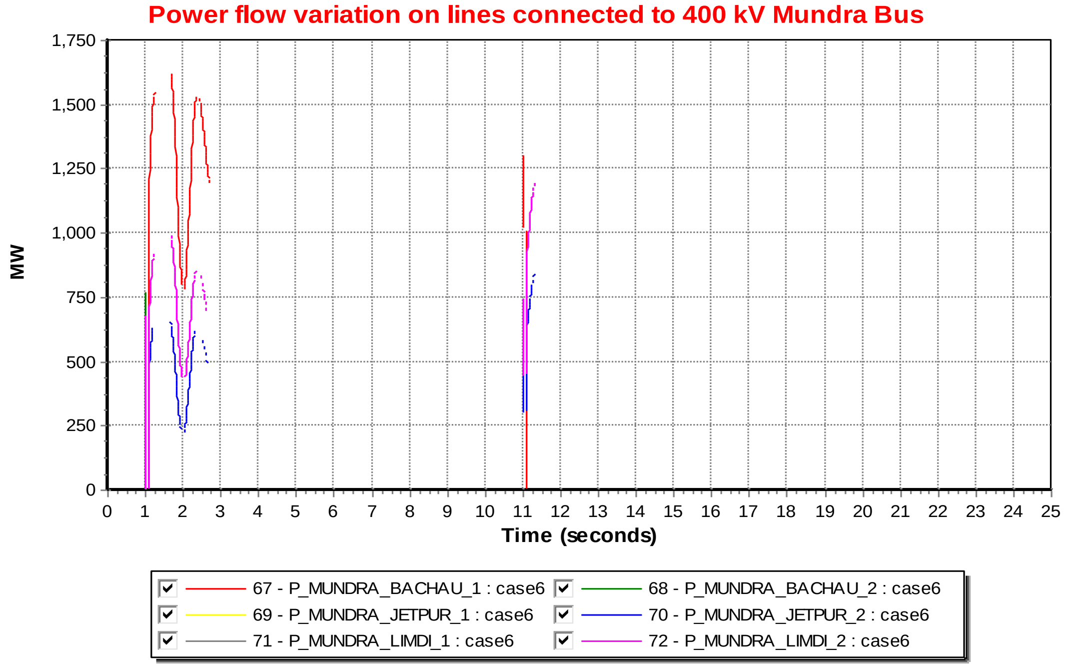
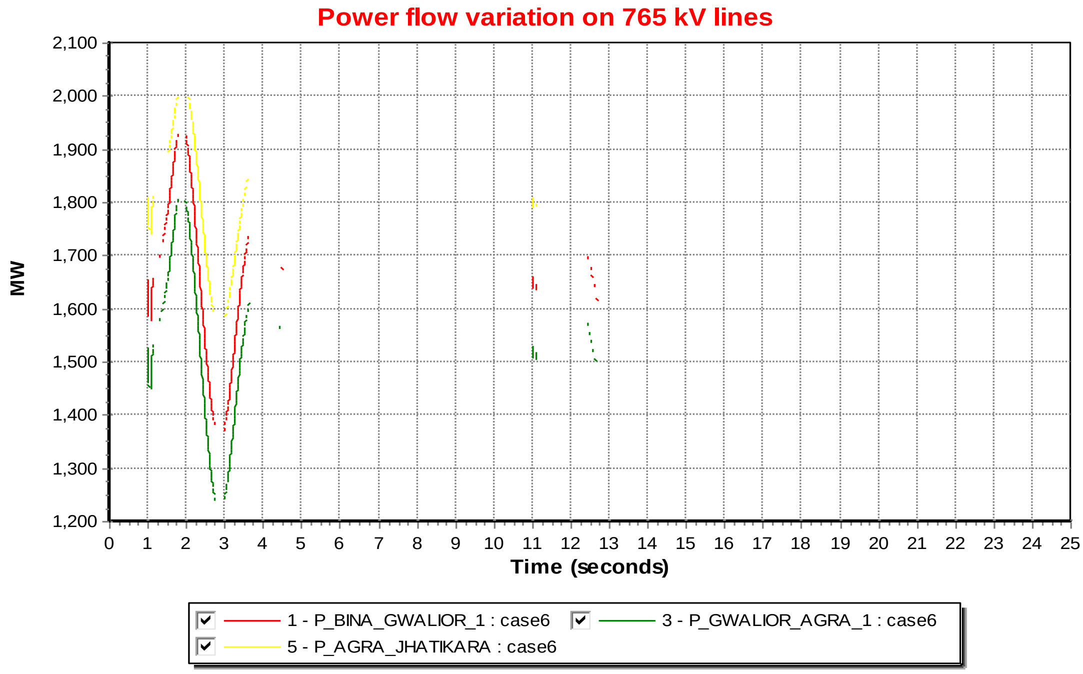
Case-6: Three phase to ground fault on 400 kV CGPL Mundra-Bachau-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV CGPL Mundra-Bachau-2 line 10 seconds later which is cleared in 100ms by a three phase trip.

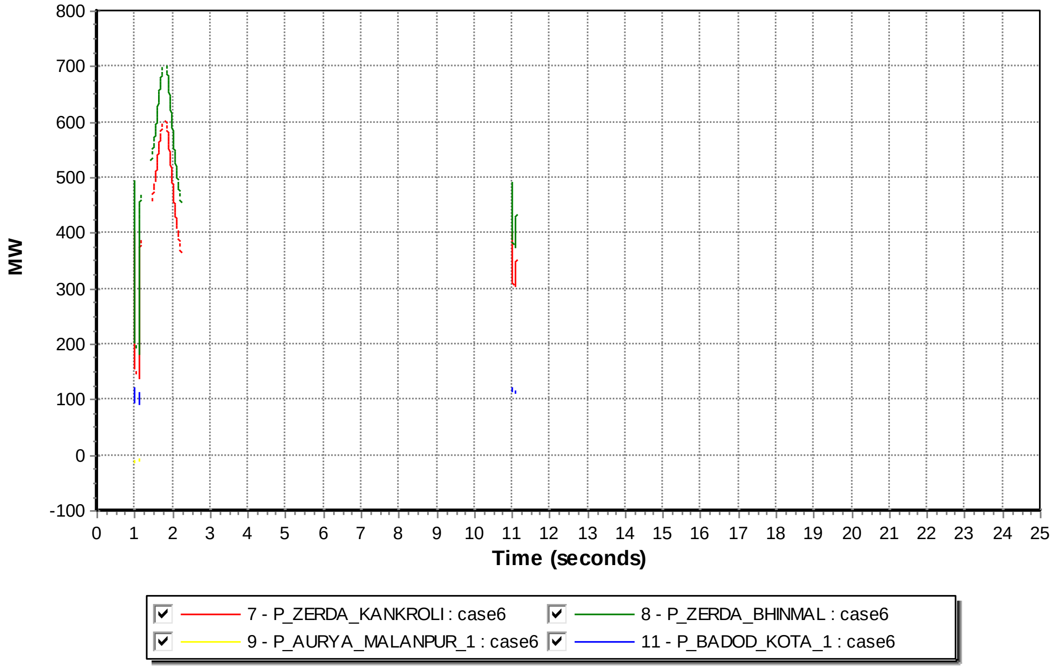




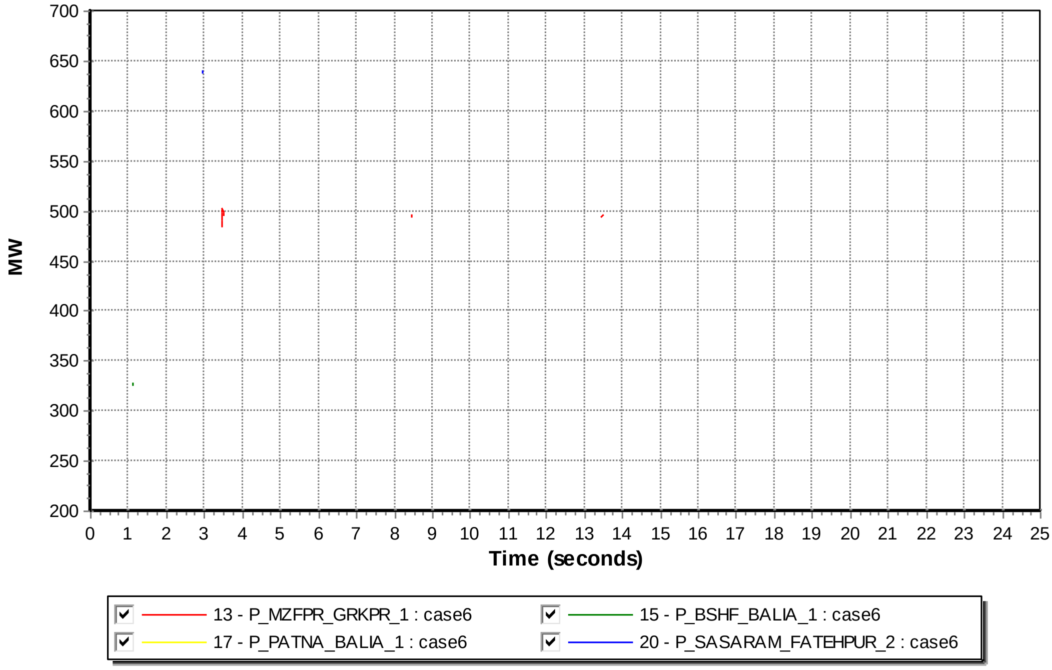
Appendix 4.1
(Page 14/20 of Appendix)

Stability Plots Case-6, Page-2/3

Power flow variation on WR-NR lines



Power flow variation on ER-NR lines



Appendix 4.1

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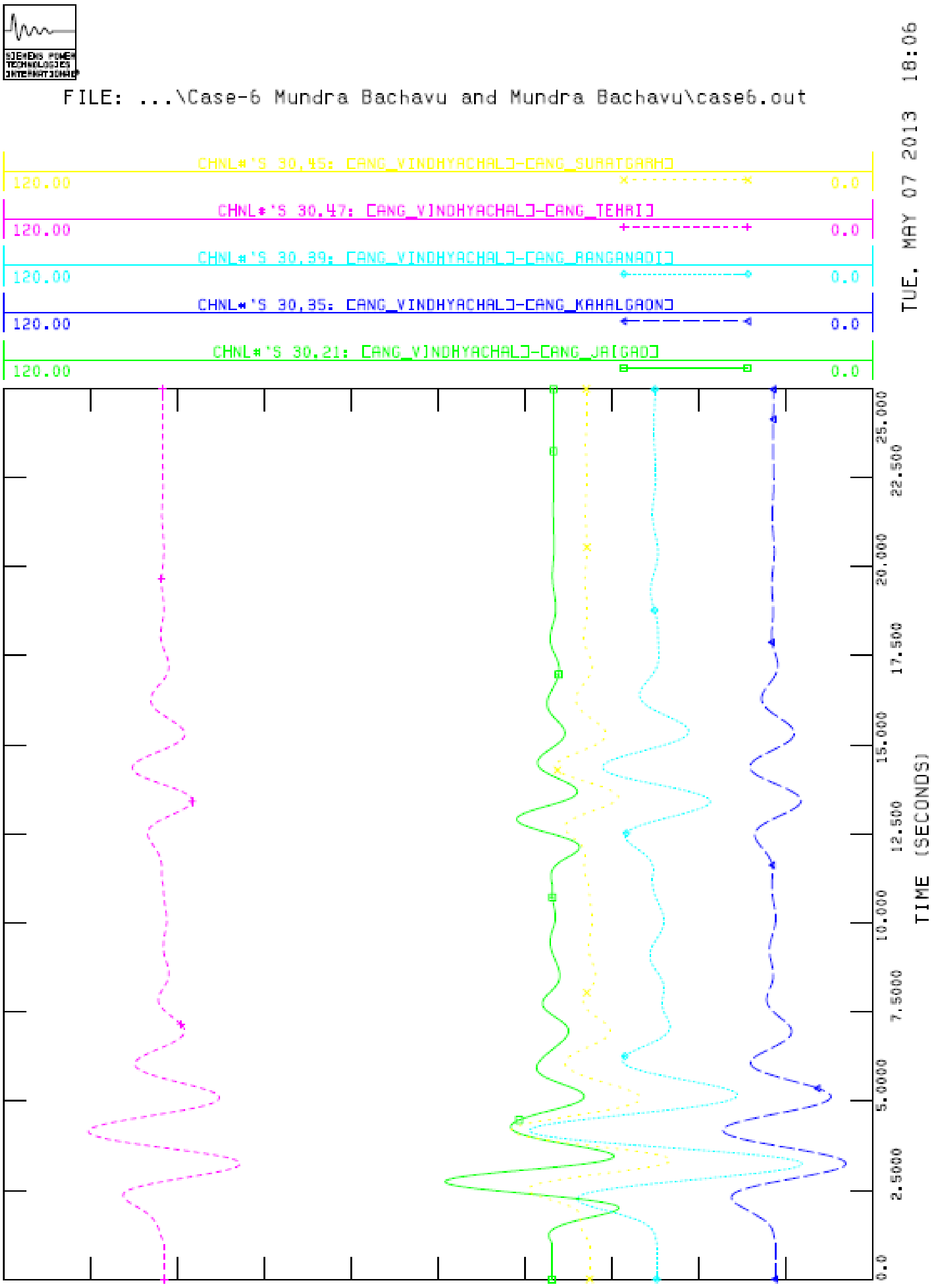
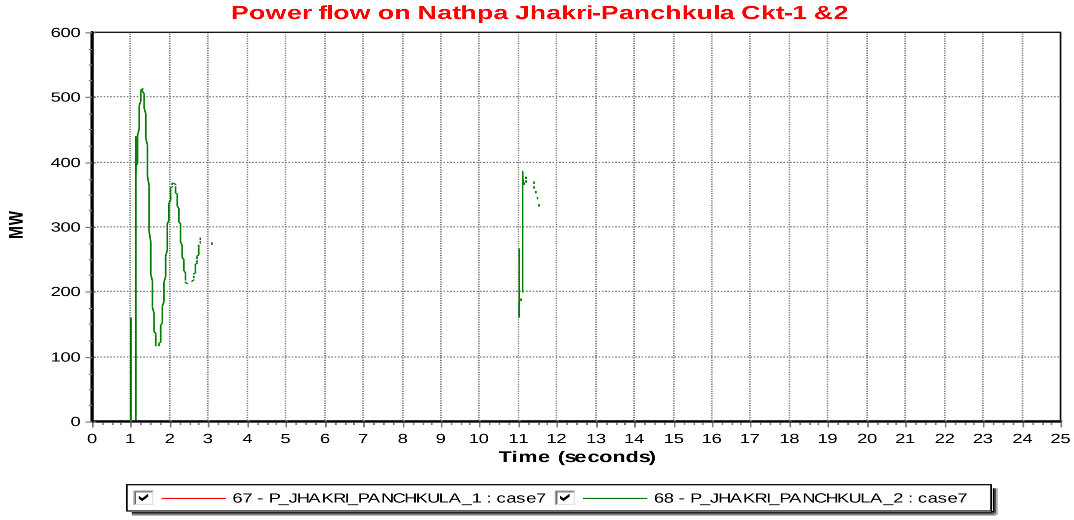
Stability Plots Case-6, Page-3/3

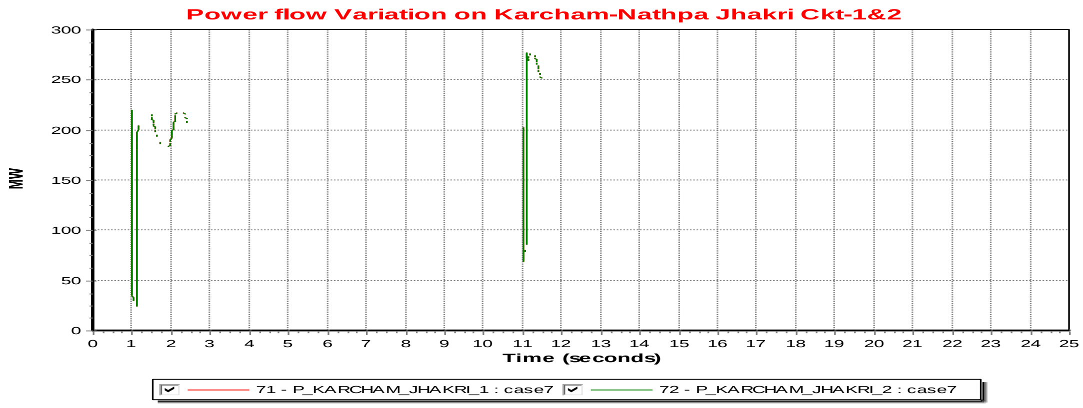


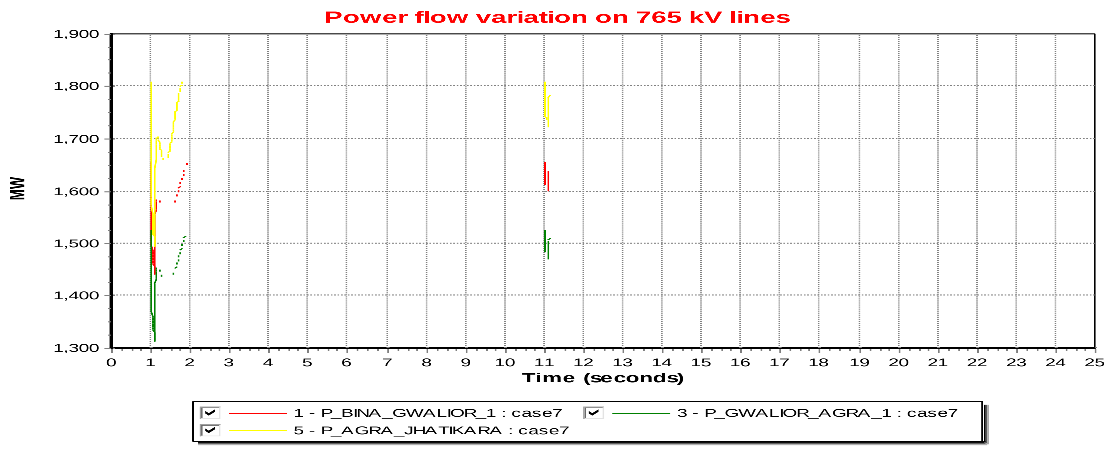
Appendix 4.1
(Page 16/20 of Appendix)

Stability Plots Case-7, Page-1/2

Case-7: Three phase to ground fault on 400 kV Jhakri-Panchkula-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Karcham-Abdullapur-1 line 10 seconds later which is cleared in 100ms by a three phase trip.







Appendix 4.1

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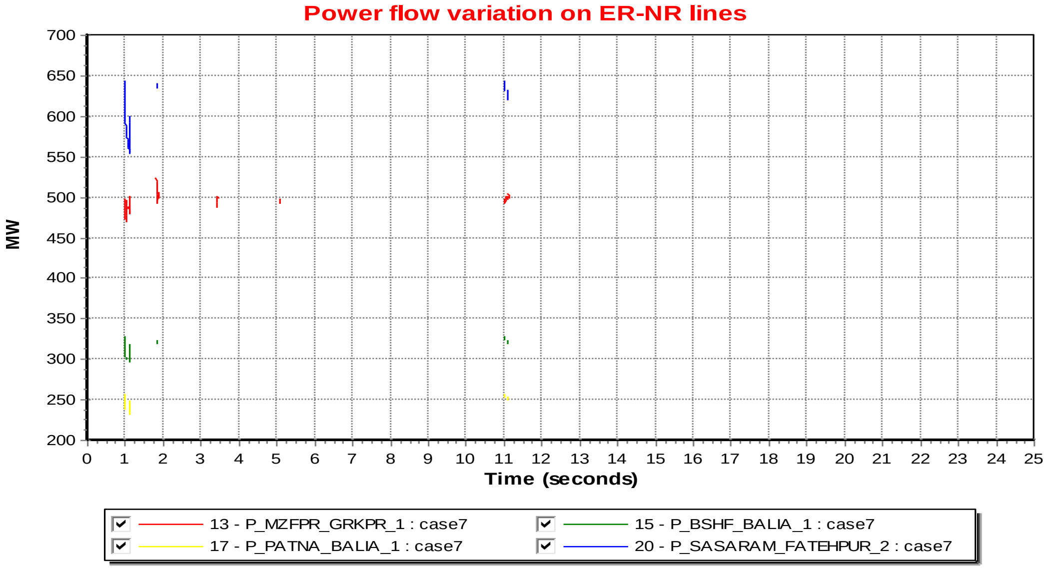
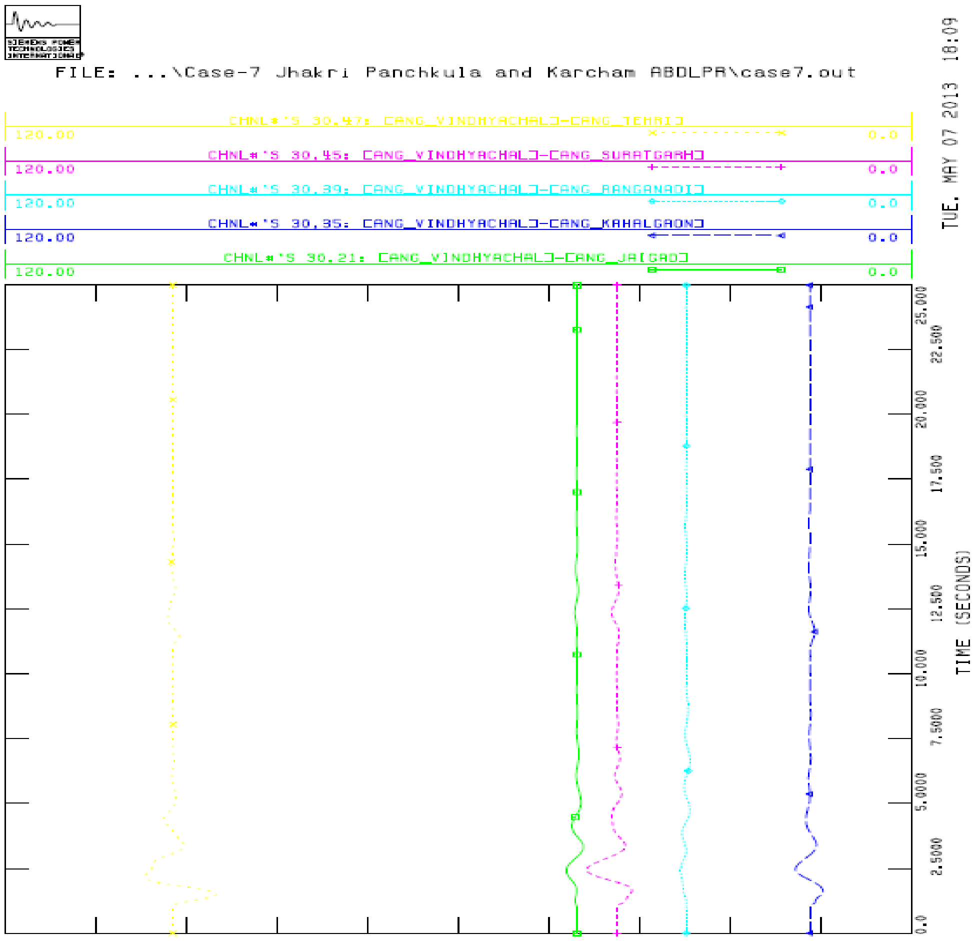
Stability Plots Case-7, Page-2/2





Appendix 4.1

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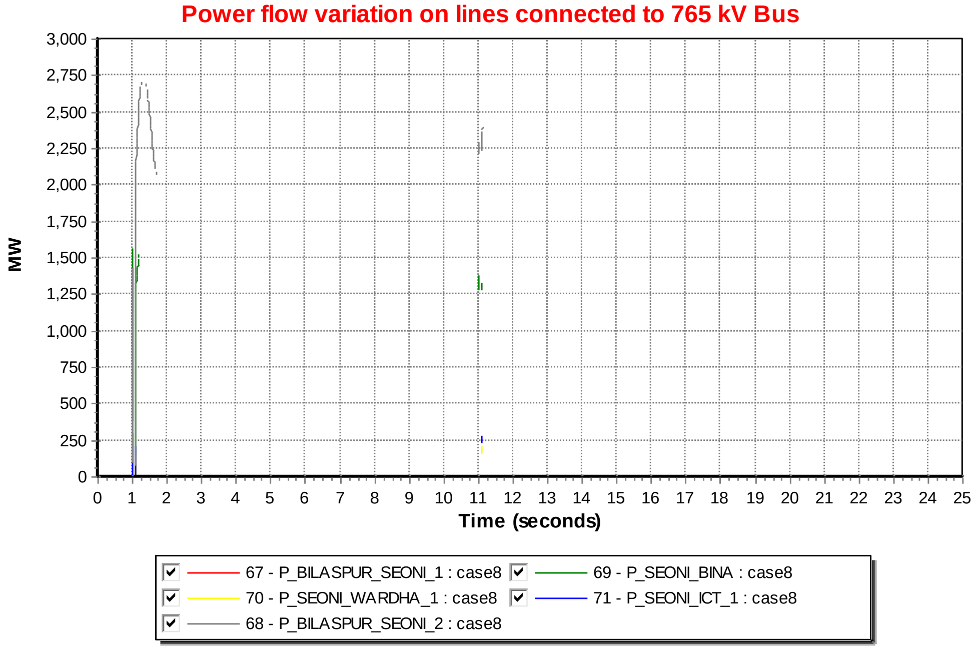
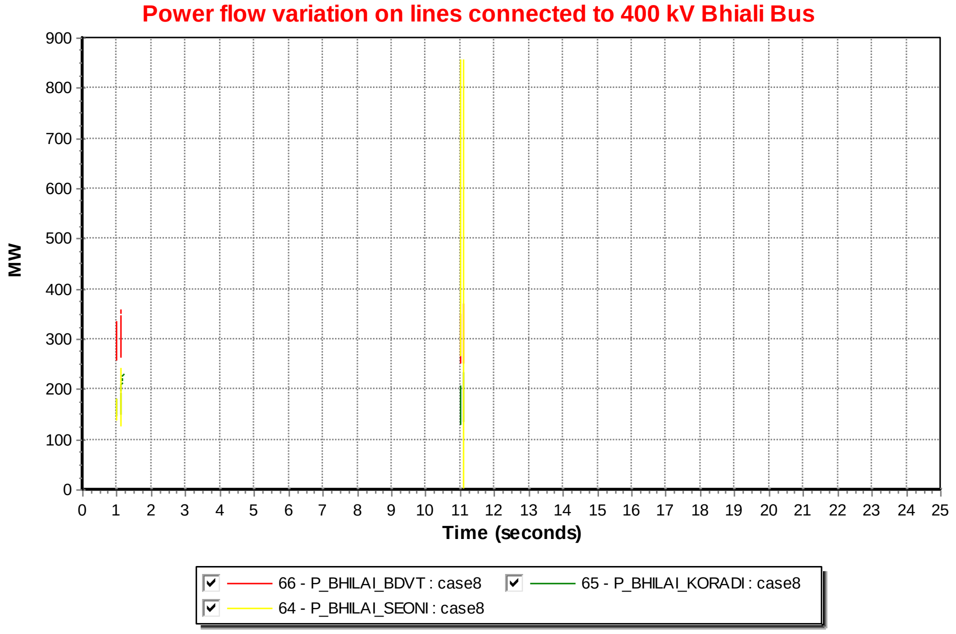
Stability Plots Case-8, Page-1/2

Case-8: Three phase to ground fault on 765 kV Bilaspur-Seoni-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV Bhilai-Seoni line 10 seconds later which is cleared in 100ms by a three phase trip.





Appendix 4.1

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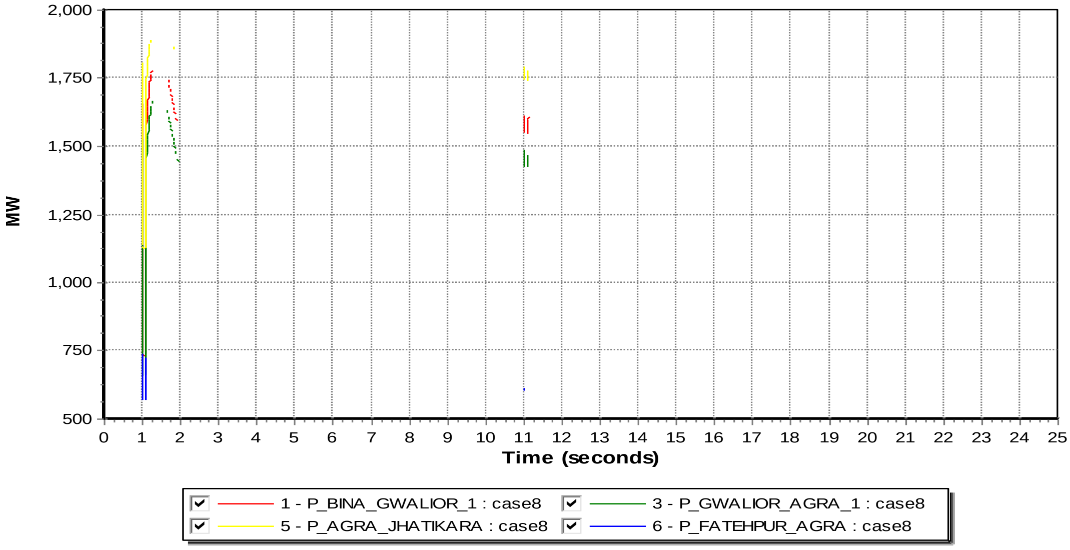
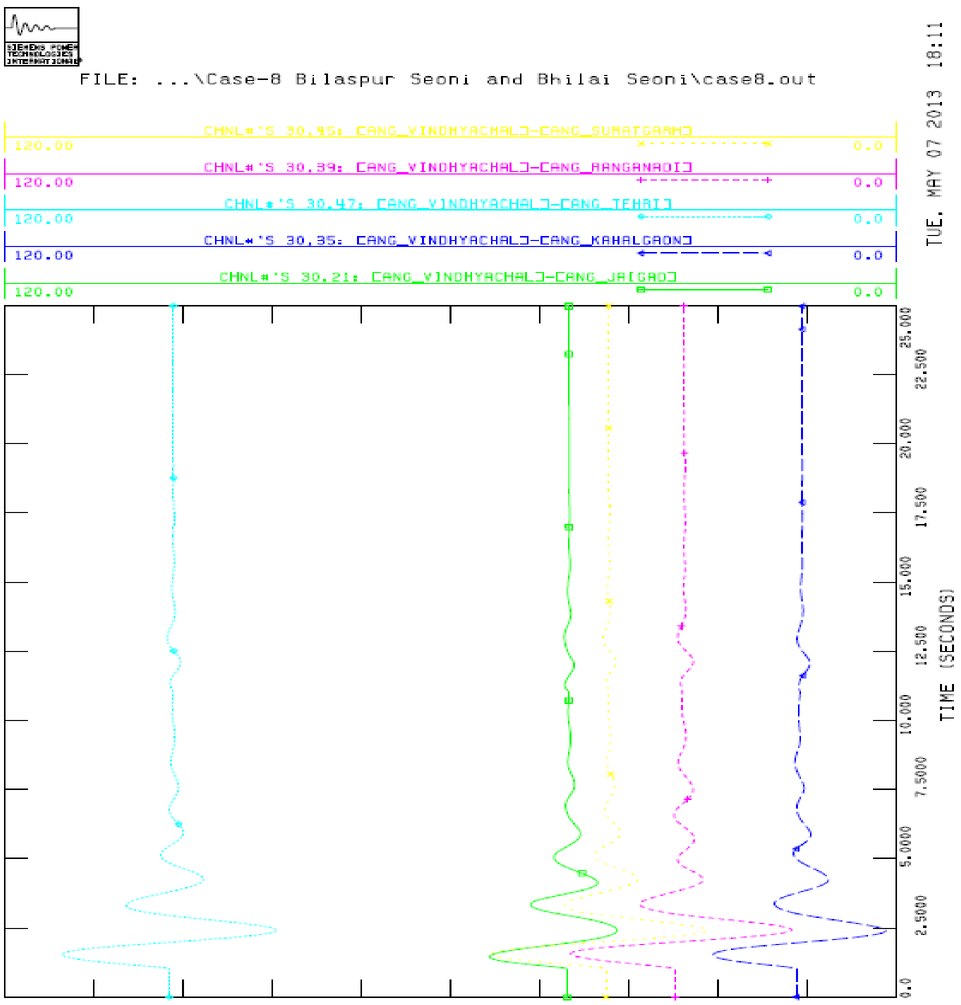
Stability Plots Case-8, Page-2/2

Power flow variation on 765 kV lines

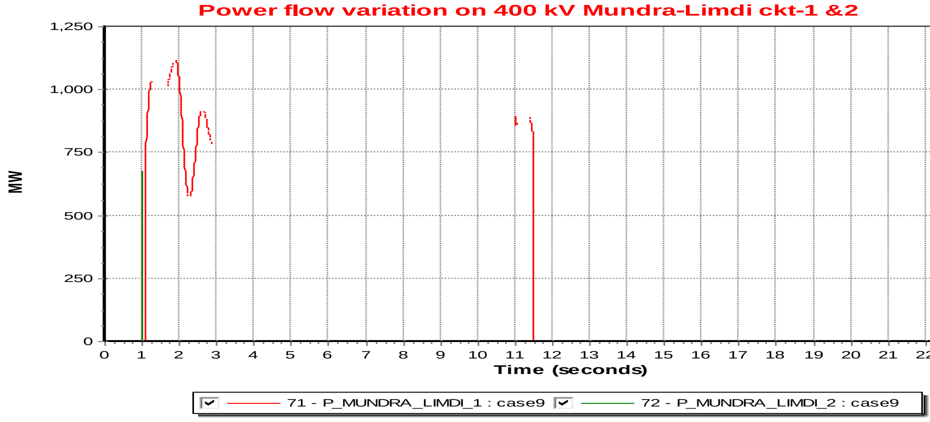


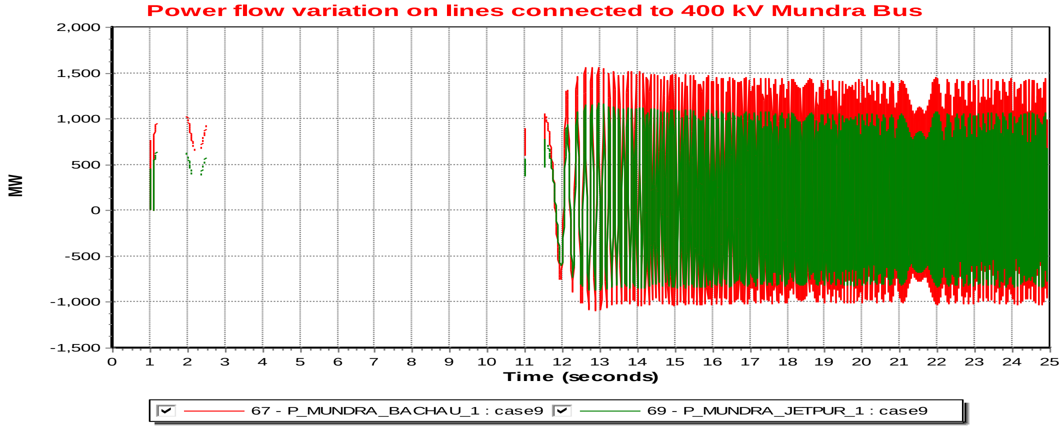


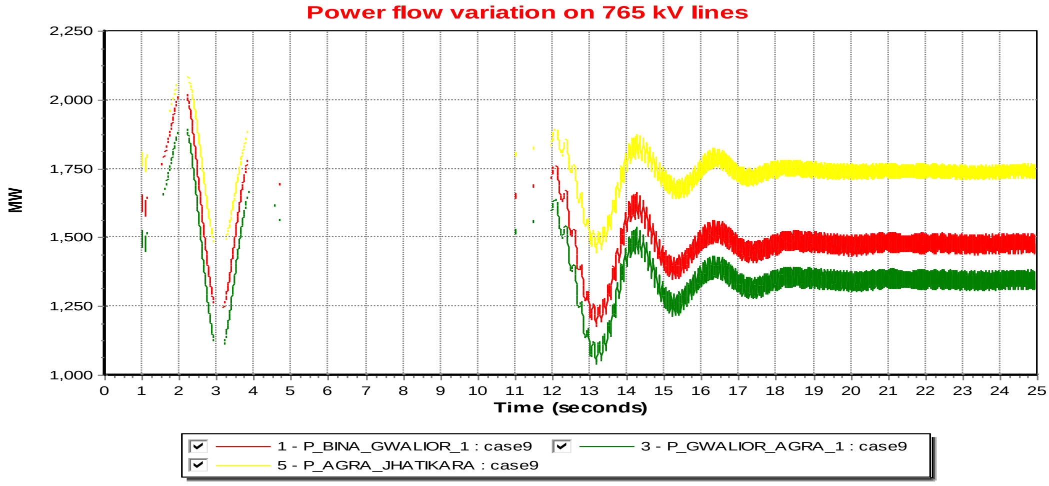
Appendix 4.1
(Page 20/20 of Appendix)

Stability Plots Case-9, Page-1/1

Case-9: Three phase to ground fault on 400 kV CGPL Mundra-Limdi-1 line cleared in 100 msec by three phase tripping of the line. This is followed by a single phase to ground fault on 400 kV CGPL Mundra-Limdi-2 line 10 seconds later which is cleared in 500ms by a three phase trip.







CHAPTER – V

5. ISLANDING PHILOSOPHY

5.1 The report on Grid Disturbances has specific recommendations on implementation of certain islanding schemes. Islanding scheme for Delhi system having four islands has been proposed. Many of the utilities are also planning to have islanding schemes covering some of the generation plants along with loads that can be isolated together with generation plants. If all these proposals are accepted and implemented, the system would have a very large number of islanding schemes. The task force has observed that large number of islanding schemes may not be in interest of secure integrated operation of grid.

5.2 The Task Force felt that instead of planning large number of islanding scheme in an adhoc manner, it would be better to evolve some guidelines based on which proposals for islanding schemes could be formulated. From available literature on the subject, it is observed that there is no standard procedure for designing of islanding schemes. The basic idea of islanding scheme is to devise a defense mechanism as a final stage remedial measure for power system defense plan in which a part of the system is islanded from a disturbed grid so that if healthy, this subpart could survive in isolation from rest of grid. Islanding should take place only when all other defense plan have been allowed their full opportunity to bring back and maintain system integrity and still the health of integrated system is on path of deteriation towards failure.

5.3 Basic motivation for devising an islanding scheme is that it helps us in saving from total blackout during a major grid disturbance. A successfully survived island also helps in quicker restoration of grid. However, it is necessary to ensure that islanding schemes operate only as a final stage defense mechanism. For this we must keep operational frequency band for pre-islanding defense mechanism and islanding frequency band sufficiently apart. This frequency gap is necessary to take care of continued fall of frequency during the interval between relay pick-up and breaker opening. Thus if any islanding is to be designed with a trigger at 48.2 HZ, lowest setting of pre-islanding U/F load shedding relays should be at 48.7 Hz or above. Similarly, a clear gap between frequency band of normal operation and highest setting of U/F load shedding relays is also necessary.

5.4 Certain specific sub-parts of network which connect to rest of grid radially with only a few interconnecting lines and having their own load generation balance, are inherently in an advantageous position with respect to design of islanding scheme. For example Mumbai system is interconnected to rest of the grid through MSETCL network in a radial manner through a few 220 kV lines. It also has a fairly good load generation balance of its own most of the time. Islanding and subsequent isolated operation of Mumbai system from the rest of the grid under distress has mostly been successful. Details of Mumbai Islanding scheme are given in Appendix 5.1 at the end of this chapter.

5.5 It also observed that in the proposed islanding scheme for Delhi, opening of a large number of elements has been envisaged. For the island formation, all the elements connecting to rest of grid have to be opened simultaneously. Failure in simultaneous opening of interconnecting feeders can happen due to communication failure or mal operation. This may jeopardize successful formation of Delhi Island. Also, the rest of grid would lose all interconnecting lines along with islanding sub part and it would cause major depletion in an already distressed grid. If trigger occurs in a mal-operation, the islanding scheme itself would become a cause of grid disturbance.

5.6 Generation plants having captive load or directly connected when bulk load have an advantage in isolating from distress grid. Such generating stations prefer to plan their own islanding scheme triggered at an early stage of distress. This may be ok for plants of small size having vintage units. For example Rithala 20MW in Delhi islanding at 48.2 Hz as against 47.9 Hz for Delhi islanding may be considered ok. However, such early exits of large size plants of 50MW and above may adversely affect the rest of grid. It was noted by the task force that CPPs/IPPs in Orissa have implemented their own isolation from grid at 48.5 Hz. Scheme for such isolation of large capacity from grid would adversely affect the grid security. It is recommended that such isolation should be discouraged. Some of the countries have specified regulation prohibiting generating units from islanding at an early stage of distress. There seems a need for similar regulation of our grid.

5.7 It is very important that an islanding sub-system achieves its load generation balance immediately following its separation from rest of the grid. This requires an automated mechanism. Further, once islanded, the sub-network must control its frequency on its own. Three types of methods have been used for achieving this:

(1) Automated remote controlled disconnection of specific load feeders based on values of power flows on interconnecting lines and load feeders as obtained from telemetered data for the measurement cycle just prior to islanding. Subsequent to island formation, a combination of logic based feeder connection/disconnection and frequency control by generating units in the island achieved the required load generation balance in the islanded system. This scheme offers good chances for success of islanded operation. Automated system based on this logic has been implemented in Mumbai islanding scheme.

(2) Disconnecting those feeders on which load variation is on larges side and keeping connected only those feeders/lines on which loads are generally constant. Subsequent to island formation, fast acting controls of generating units in the island adjust generation to balance load and regulate the frequency of islanded system. Islanding scheme for Narora APP is based on this logic.

(3) Post islanding U/F load shedding for frequency recovery followed by generation control to regulate the frequency of islanded system. Proposal for Delhi islanding scheme has been formulated on this basis.

5.8 For successful operation of islanded system, sufficient number/capacity of generating units in the island should be on free governor mode of operation. Also, load connection/disconnection should be possible remotely from the dispatch centre of the islanded sub-system. Any deficiency in this will lead to failure of islanded operation defeating the very purpose of this defense mechanism. It is therefore necessary that all facilities including electrical, mechanical, electronics and communication systems are kept in good health all the time.

5.9 Islanding schemes, while saving us from a total blackout, also results in avoiding supply disruption to important loads during a major grid disturbance. Many a times, this consideration for avoiding supply disruption to important loads itself becomes a motivation for proposing an islanding scheme. However, the basic purpose of islanding scheme should be to have a defense mechanism for avoiding total blackout and quicker restoration of failed grid. Generally, an islanding scheme should not be taken as a system for ensuring continued supply to important loads. Necessary arrangement for emergency supply to important critical loads must be made separately. This should invariably be designed and implemented independent of supply from grid along with necessary changeover arrangement for un-interrupted power supply to critical areas/equipments.

5.10 Based on detailed discussions held in the task force meetings, the following guidelines are proposed for the purpose of proposing, evaluating, reviewing, finalizing and implementing islanding schemes:

(1) Islanding should take place **only when** all other defense plan viz. fault clearance, SPS action, under frequency load shedding and df/dt load shedding etc have been allowed their final operational opportunity and the system is still on the path of deterioration towards collapse.

(2) Islanding **should not take place** if there is still a chance that a distressed system can be brought back to emergency condition (or alert condition or normal condition) with operation of the mechanism planed for integrated and interconnected states of Grid.

(3) Sufficient gaps should be maintained between frequency band of normal operation, frequency band for pre-islanding defense mechanism and trigger frequencies of islanding schemes. The following is recommended:

Frequencies for trigger of islanding	47.8 Hz , 47.9 Hz, 48.0 Hz, 48.2 Hz
Pre-islanding U/F load shedding	48.6 Hz, 49.2 Hz
Emergency Load management band	49.2-49.5 Hz
Alert/ Urgent Load management band	49.5-49.8 Hz
Normal operation	49.8 to 50.1 Hz

The above frequency bands should be reviewed and further narrowed down after two years.

(4) System specific islanding scheme solution should be devised leading to preserve those areas which inherently are in a position to achieve load generation balance post islanding.

(5) In every islanding scheme, adequate automated mechanism should be implemented for achieving load generation balance in the islanded sub-system. Also, for frequency control of islanded sub-system there should be sufficient number/capacity of generating units in the island on free governor mode of operation. Also, load connection/ disconnection should be possible remotely from the

dispatch centre of the islanded sub-system. Health of all facilities required in the islanding scheme should be closely monitored so as keep at the necessary electrical, mechanical, electronics and communication systems in good health all the time.

(6) Islanding schemes should generally be implemented for only those sub-parts of network which connect to rest of grid in an electrically radial manner with only a few interconnecting lines and having their own load generation balance to a large extent, requiring comparatively smaller exchanges with rest of the grid. Besides Mumbai system where successful islanding scheme is already in place, following specific sub-part could be suitable for designing islanding schemes:

- Ramagundam generating station with loads of Hyderabad.
- CESC System along with its generating stations.
- Tuticorin and Kudankulam generating stations along with load of south Tamil Nadu. However, all wind generation should be excluded.
- Sugen /Torrent generation along with loads of Surat and Ahmedabad.
- Other suitable areas, not necessarily radial but which could be isolated from rest of grid by tripping of very few interconnecting lines without causing much transmission depletion in rest of grid.

(7) Islanding schemes should not be taken as a system for continued supply to important loads. Necessary arrangement for emergency supply to important critical loads must be made separately.

(8) Islanding schemes involving only hydro generation is generally not recommended due to wide variation in hydro generation from season to season and during peak/off-peak hours of day.

(9) Wind generations must be kept out of islanding schemes. If the islanding sub-area includes wind generation, these must be disconnected at the time of formation of island.

(10) Solar generation should also be generally kept out of islanded sub-system.

(11) The details of the Mumbai Islanding scheme is annexed to the report. This may serve as an example for designing islanding schemes.

Appendix 5.1

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MUMBAI ISLANDING SCHEME

Mumbai islanding scheme has been designed to intentionally isolate parts of the power system network during grid disturbance leading to possible black out.

Objectives of islanding are:

- To provide un-interrupted power supply to essential category consumers
- To avoid tripping of Thermal Generators
- To facilitate quick restoration of the failed system

Mumbai Power System comprises of Tata Power and R-Infra generating units connected to Transmission network, which, in turn, is connected to rest of the grid through 21 tie lines at four MSETCL Receiving Stations i.e., Trombay, Kalwa, Borivli and Boisar. Also, RInfra Dahanu generating units and associated transmission network is connected to Tata Power transmission network through two tie lines at Tata Power - Borivali Receiving Station. Thus boundary of Mumbai Island has been identified.

MSETCL network is a part of bigger system consisting Western, Northern, Eastern and North-eastern grids or NEW grid. Mumbai System island thus defined, has generation capacity of 2377MW and a peak load of about 3400MW. Around 600 -1100 MW normally flows on the tie points.

Islanding Scheme :

The Islanding scheme is developed to protect Tata power system in case of major disturbance, outside Mumbai system, leading to blackout. Combination of under-frequency condition and power flow into the grid will result in tripping of all tie line breakers to isolate Mumbai system from MSETCL network. The scheme ***simultaneously*** operates at all tie points. Under-frequency relays, commissioned at various stations, operate prior to islanding to get sufficient quantum of load relief which helps in frequency recovery. ***Thus, after islanding, load generation balance is achieved and Mumbai System continues to feed essential category consumers like Railways depending on available generation capacity within the Mumbai Island.***

Further, a second stage islanding scheme is provided between Tata Power and RInfra Dahanu to insulate each of the systems against any further deterioration leading to black out in Mumbai. In case of power flow from Tata Power system to R-Infra system coupled with under-frequency condition, R-Infra system is isolated

Appendix 5.1

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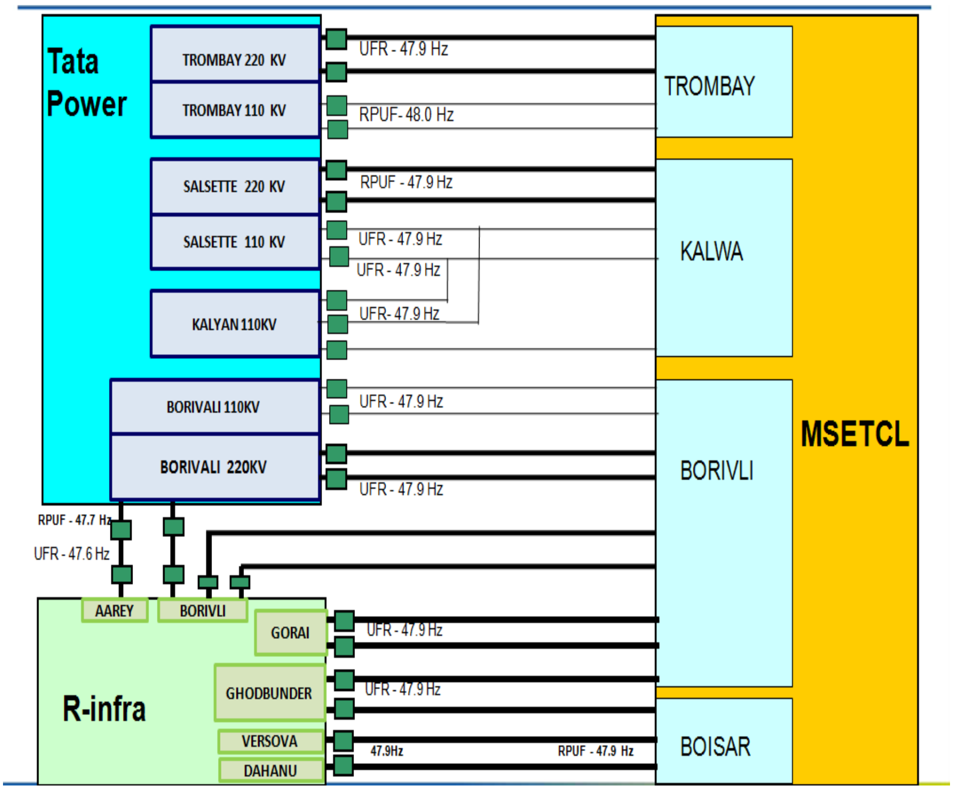
from Tata Power system at Borivli (47.7 Hz) to ensure continuity of supply in Tata System. Redundancy is provided in the form of Main 1 & Main 2 islanding schemes. In case of failure or stuck breaker condition, at 47.0 Hz LBBU of that breaker operates and gets isolated from the network.

In addition, to take care of further eventualities, Thermal and Hydro generating plants have been provided with **Unit islanding schemes**, which will facilitate quick restoration in case of blackout. Also for controlling frequency after islanding, scheme is provided for units to actively participate in frequency control.

Tata Power designed the islanding scheme way back in 1981 at frequency setting of 47.5 Hz with Reverse Power condition, to trip all tie points simultaneously. This scheme has undergone seven changes in line with the development in Mumbai network and generation addition and learning from each occurrence. Details of the Existing Islanding scheme are given in the diagram shown below:



Appendix 5.1

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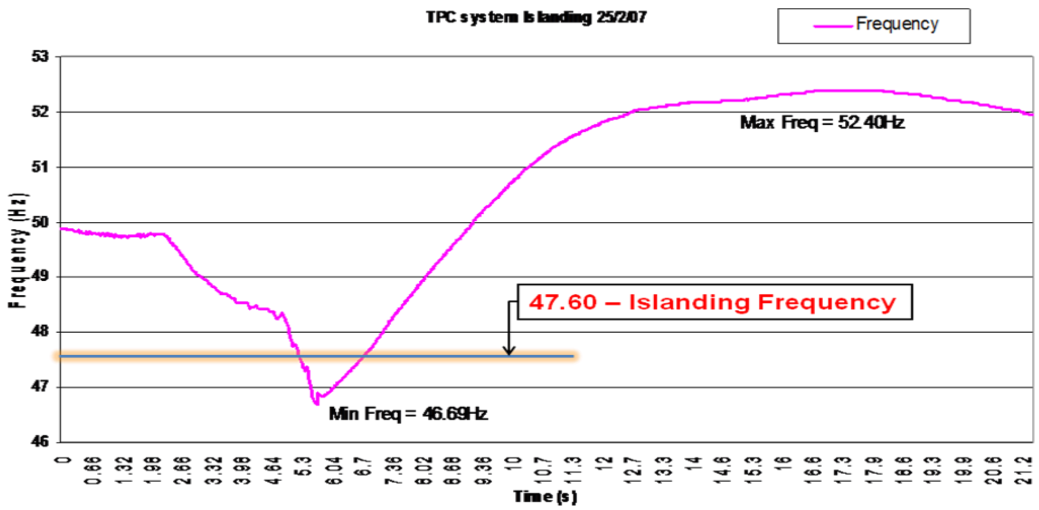
Keeping Mumbai System "Island Ready" prior to any disturbance:

Under normal operating conditions, generation and tie line exchanges are maintained as per the pre-determined schedules. Generation adjustments are done vis-a-vis demand on the system. During steady state, on real time basis, software logic developed on SCADA determines load shedding requirement for successful survival after islanding. Accordingly Under frequency relays at various stations are enabled /disabled and the system is kept ready to achieve load relief in the event of disturbance. Thus, by closely monitoring the exchange on tie lines vis-a-vis the quantum of load shedding required in case of islanding, chances of survival is enhanced. About 1400 MW load is connected to Under-frequency load shedding scheme. In addition, frequency trend relays (0.5 Hz/sec) are available with total connected load of about 900 MW.

Operation of Mumbai System while Islanding:

Major disturbance is sensed by frequency decay along with reversal of power flow into the grid. At 48.0 / 47.9 Hz under-frequency load shedding takes place by way of opening designated non essential feeders, prior to islanding**, to ensure generation-rich island for survival post islanding.**

After islanding, the frequency in the island recovers because of higher generation and depending upon the mismatch, frequency may shoot up to high value. Typical behavior is as indicated in the figure given below.



**** Islanding frequency setting has been changed to 47.9 Hz since November, 2007 as per the recommendation of WRPC.**

Appendix 5.1

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When frequency shoots up, response from the generators are expected as below:

- At 51.5 Hz, high frequency anti acceleration protection on Trombay Unit 5, 6 & 8 will drop load with 5% droop.
- At 51.5 Hz, 30 sec time delay, Unit 7A trips on class C & 56 Sec time delay - Class A.
- At 53.0 Hz, Instantaneous, Unit 7A trips on Class C & 0.6 sec time delay - Class A.

If frequency recovers to more than 50.2 Hz, **auto restoration** scheme at Borivli resumes 20 MW load in three stages at frequency setting of 50.3, 50.5 & 51.0 Hz respectively, which helps to control rise in islanded system frequency. Thus the island survives with generating units responding to demand changes and frequency is maintained.

In case frequency does not recover after islanding,

- At 47.5 Hz, 30 sec time delay Unit 7A Class C protection will operate and unit will continue to operate on house load .
- At 47.0 Hz, 2 sec time delay, 220kV GT breakers of Units 5, 6 & 8 will open and Units will run on house load.- Class C
- At 46.0 Hz, 0.6 sec time delay – Class C & at 2 Sec – Class A
- At 46.5 Hz, at Bhira, Set 2/5 gets isolated from the grid and feeds station auxiliary.

At 45.0 Hz, Hydro islanding scheme operates and trip all outgoing lines & transfer breaker. Hydro units remain on line and available for building the network. BPSU & Set No.1 at Bhira also trip. With this arrangement the generating units at all three hydro stations are kept running supplying own auxiliary power.

Operations during Islanded Mode:

- When “islanding” of Mumbai System is detected through tripping of all tie lines, all concerned agencies like SLDC, WRLDC, BEST, R-Infra, are alerted immediately.
- Different set of Under Frequency Relays, with setting starting at higher frequency setting are taken in service.
- Spinning reserve is maintained to take care of changes in demand. Also, units under minor planned outages are cleared immediately and brought on-line in order to have maximum generating capacity and achieve load-generation balance.
- Load restoration is carried-out as per the availability of generation capacity.
- ***Rotational load shedding is carried out, in case of generation shortfall, to avoid prolonged shutdown to a particular area.***
- Voltage in the islanded system is maintained by proper reactive power management.

Appendix 5.1
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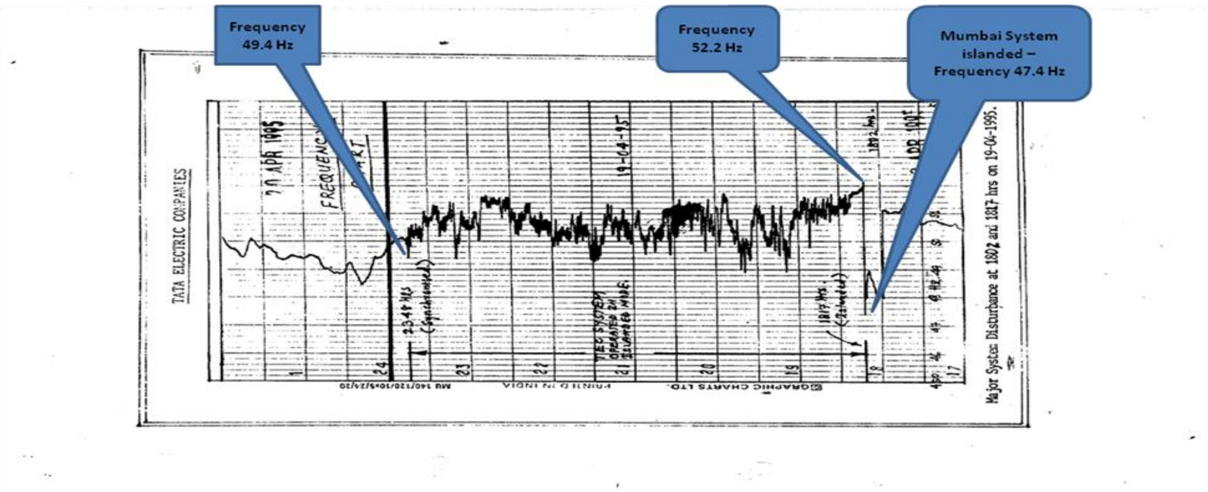
- Wide range of frequency excursion, generally between 49.0 & 51.0 Hz, is observed due to fluctuating nature of Railway load. While operating Mumbai system in islanded mode, power index comes down to about 35 – 40 MW/Hz as compared to around 2200 MW/ Hz of normal, interconnected grid operation. A typical frequency excursion graph is given below.



- All relevant operations at generating & receiving stations are carried-out <u>in consultation with Control Center **only**</u> for maintaining the islanded system.
- In case collapse of R-Infra system, start-up power is extended, at a convenient time when the condition of Tata system is stable.

<u>Synchronising Islanded system with Grid:</u>

in consultation with SLDC, when the condition of the grid improves to a reasonable level, Mumbai island is synchronized manually at one of the tie points with the Grid.

All operations in the system during islanded mode i.e. generation pick-up / drop and load shedding / restoration, are carried-out, under the guidance of a single control point thus ensures successful survival of system after islanding.

Mumbai has faced 37 major grid disturbances, since 1981 and survived successfully on 27 occasions. Since 1995 Tata Power System Islanding scheme has a 100% success rate and survived on all 16 occasions of Grid disturbances.

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CHAPTER - VI

6. DATA TELEMETRY AND PHASOR MEASUREMENT

6.1 Data Telemetry:

6.1.1 Real time data is vital for taking decisions during grid operation. Further, to maintain security and reliability of network, state estimator tool is used at control centre to determine the current state of system and perform contingency analysis. The accuracy of state estimator results also depends on the real time data availability (digital & analog) from field. With the un-bundling of utilities, restructuring & liberalization of power sector and the new regulations of open access, power exchange etc, the complexity of operation has further increased and reliable voice & data communication has become all the more critical.

6.1.2 Though there are Regulatory provisions putting the responsibility of providing telemetry to the Load Despatch Centre on the individual users who get connected to the grid, relevant data from a number of Generating Stations / Substations is still not available at the LDCs.

6.1.3 RLDCs have taken-up the issue with CERC through individual petitions. However, this is a long discussed issue in which desired success has not been achieved even after more than two decades of efforts. The Task Force is of the view that a pragmatic approach in ensuring data availability is needed. Effective solution would be to have an integrated approach with single agency responsibility.

6.2 Phasor Measurement

6.2.1 The ability of the system operators to take decisions in real-time is dependent on their "situational awareness" derived from the data/information available with them in real time. This necessitates better visibility of grid system and fast update of operating scenario integrated with intelligent computation to capture dynamic behavior of power system towards safe, secure and reliable operation on real time basis. This necessitates application of modern tools for monitoring on real time basis to give confidence to the system planner as well as operators to bring efficiency in system operation. Recent advances in measurement, communications and analytic technologies have produced a range of new options. In particular, Wide Area Measurement Systems (WAMS) have come to the fore as a means to address not just immediate reliability concerns but also operations issues like enhancing transfer capability in real time, advanced automatic corrective actions like adaptive islanding, blocking/de-blocking of distance relay zones under power swings, better visualization through state measurements, decision support tools etc.

6.2.2 Recognising the need for fast, reliable and synchronous measurement and monitoring of system state of geographically spread power network on real time basis, application of synchrophasor technology for Wide Area Measurement/Monitoring (WAMS) in Indian Power System has been proposed as "Unified Real Time Dynamic State Measurement" (URTDSM) scheme. The scheme covers placement of PMU at sub-stations and both ends of transmission lines at 400kV and above level including generating stations at 220 kV level of STU, ISTS, ISGS and IPP coming up by 2014-15 time frame. The PMU data will be integrated with the Phasor Data Concentrator(PDC) through fibre optic communication link to be installed at all SLDCs, RLDCs, NLDC, NTAMC, remote consoles at RPCs, CEA, CTU and other locations. Complex operating scenario with large, widely spread, integrated grid in new regime of open electricity market & increasing renewable penetration, this technology has capability of measuring & monitoring the system in real time, which would be helpful in better visualization of the system and utilization of existing transmission assets with reliability, security and economy.

6.2.3 The WAMS pilot project has been implemented in all the five (5) regions of the country. These pilot projects have demonstrated the enhancement in situational awareness that can be achieved in real time at load dispatch centers through dynamic real time measurements and better visualization of power system which are useful in monitoring safety and security of the grid as well as undertaking control/corrective actions. It has helped in improving/enhancing situational awareness by tracking the phase-angle separation, df/dt, voltage phasors and line loadings. With PMU data it has also become possible to identify the line tripping, generator tripping, inter area oscillations, load crash & auto-reclosure of lines. The archived PMU data has helped in the analysis of grid events, validation of protection schemes and validation of transfer capability through different flow gates. The WAMS technology has brought about a paradigm shift from state estimation to state measurement. The Scheme shall enhance the efficiency in overall grid management in electricity open market regime.

6.2.4 In addition, possible utilization of PMU data through analytical software viz. line parameter validation, vulnerability analysis of distance relay, supervised zone-3 blocking, dynamic (linear) state estimator, Capacitive Voltage Transformer(CVT) parameter validation, Current Transformer(CT) validation, angular stability, control scheme based on voltage instability, angular stability are being developed in association with IIT Bombay.

6.2.5 The Task Force deliberated upon the benefits of the scheme for enhancement of data acquisition through synchro phaser based WAMS, employing PMUs and it emerged that there was a need for understanding the benefits and development of applications related to synchro-phasor based monitoring system. Once the systems are implemented and applications using this data are developed, load dispatchers will have a better overview of real time security parameters and operational system security is expected to improve significantly.

6.3 Synchrophasor technology

6.3.1 A phasor is a complex number that represents both the magnitude and phase angle of the sine waves found in AC system as shown in figure 1

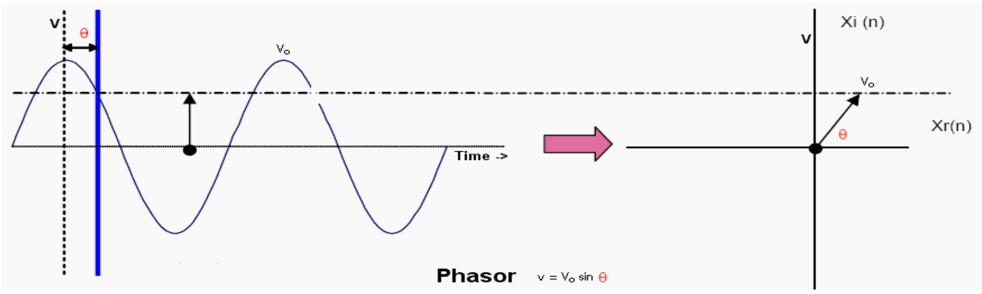

Fig.1: Phasor representing magnitude & phase angle of sine wave of voltage or current.

Phasor measurements that occur at the same time are called "synchrophasors" and can be measured precisely by the Phasor measurement units (PMUs). PMU measurements are taken at high speed typically 25 or 50 samples per second – compared to one every 4 to 10 seconds using conventional technology. Each measurement is time-stamped according to a common time reference. Time stamping allows phasors at different locations to be time-aligned (or synchronized) thus providing a comprehensive view of the entire grid at central location.

6.3.2 A typical PMU installation as a part of wide area measurement/monitoring system (WAMS) network consists of phasor measurement units (PMUs) dispersaly placed throughout the electricity grid at strategic locations in order to cover the diverse footprint of the grid. A Phasor Data Concentrator (PDC) at central location collects the information from PMUs and provides alert and alarm for emergency situations as well as facilitates development of different types of analytics for smooth operation of grid on real time basis. The PMU data is also transmitted to Supervisory Control and Data Acquisition (SCADA) system after time aligning the same. The WAMS technology requires high bandwidth communication network for rapid data transfer matching the frequency of sampling of the PMU data.

6.3.3 Phasor Data Concentrator (PDC): The electrical parameters measured by a number of PMUs are to be collected by some device either locally or remotely, this function is performed by Phasor Data Concentrator (PDC). A PDC forms a node in a system where phasor data from a number of PMUs is collected, correlated and fed as a single stream to other applications. In a hierarchal set up the PDCs can also be used to collect the data from number of downstream PDCs. PDC provides additional functions as under:

- It performs quality checks on the phasor data and inserts appropriate flags
- It checks disturbance flags and records files of data for analysis
- It monitors the overall measurement system and provides a display and record of performance
- It can provide a number of specialized outputs that can be interfaced with the other system e.g. SCADA/EMS system.

6.4 Phasor Measurement practice in India

6.4.1 National and Regional Load Despatch Centres as well as State Load Despatch Centres are equipped with SCADA/EMS system. Telemetry from different sub-stations and power plants are being received at each SLDC/RLDC and subsequently to NLDC which are being utilized in day to day operations of the regional grid. Synchronous Interconnection of regional grids forming large interconnected system and various changes undergoing in the Indian power industry requires better visualization of grid events/status at the control center for real time system operation. Phase angle measurements, which provides information about angular separation between different nodes, are commonly used in auto synchronization of generating stations and check synchronization relays used at substations for closing of lines as well as during three-phase auto-reclosing. All these applications are at the local level.

6.4.2 SCADA technology based on telemetry of non-phasor measurements, provides an estimate of phase angle difference (with respect to a reference bus) through the State Estimator, a software which uses mathematical algorithm to estimate the system state from SCADA inputs (analogue and digital measurands). However, this method of calculation of phase angle differences has limitations due to resolution, data latency, update time and data skewedness. Update time in the SCADA system is considerably large (up to 10-15 seconds) for visualizing and controlling the dynamics of power system. The real time angular measurement in the power system avoids above uncertainties and can be relied on to assess the transmission capability in real time which is very crucial in efficiently operating the present electricity market mechanism. PMUs are able to measure phase difference at different substations.

6.5 PMU pilot project in Northern Regional Grid

PMU pilot Project in Northern Region has helped a lot understanding the new technology and system operation in real time, protection co-ordination, disturbance analysis etc. Case study available to demonstrate better transmission system utilization with reliability for evacuation of Karcham-Wangtoo hydro generation along with Baspa and Jhakri Hydro generation during the monsoon season in 2011 with the help of PMU based measurements. Delay in SPS settings was identified and then rectified (Fig 2). This has facilitated full evacuation of power from Karcham-Wangtoo.

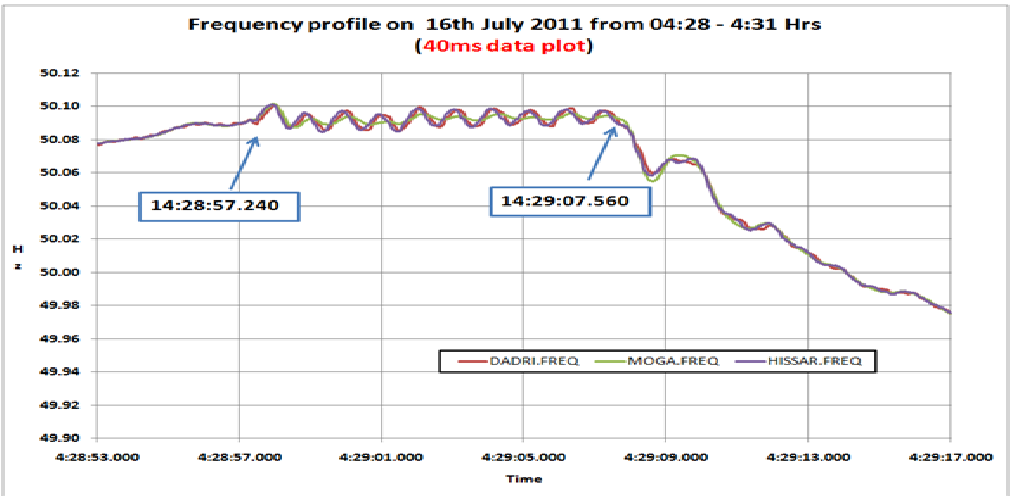

Fig 2: Delay in SPS operating settings at Karcham-Wangtoo unit

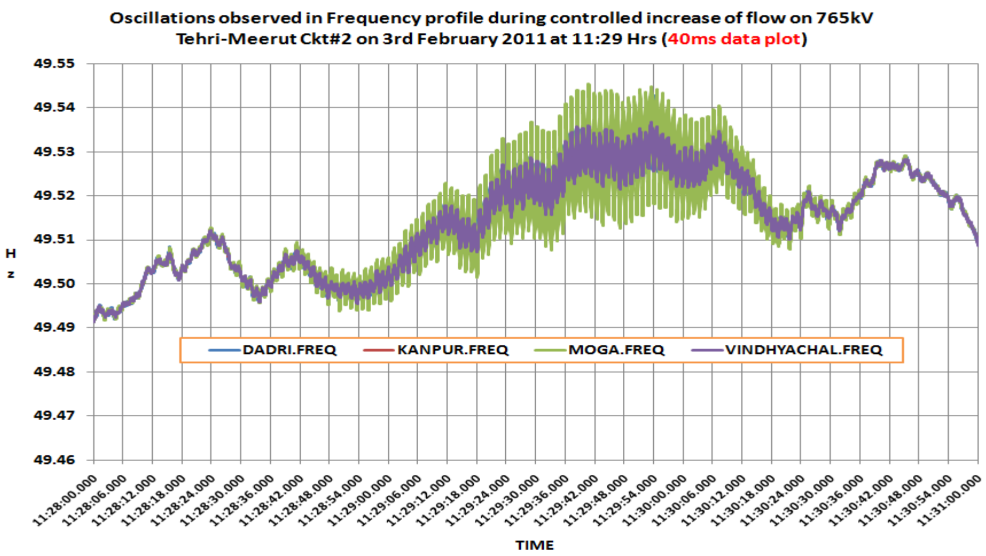

Fig 3: Oscillations in Tehri Unit

PMU also helped in detection of oscillations on 765kV Tehri-Meerut line (Charged at 400kV) [Fig 3]. Based on PMU data PSS tuning was done to avoid such oscillations. During foggy winter nights, large number of auto-reclosure operations took place (Fig 4) and its detection in real time by system operator helped a lot in effective real time monitoring and control of the grid. PMU technology is a kind of meta tool that will create new tools in future.

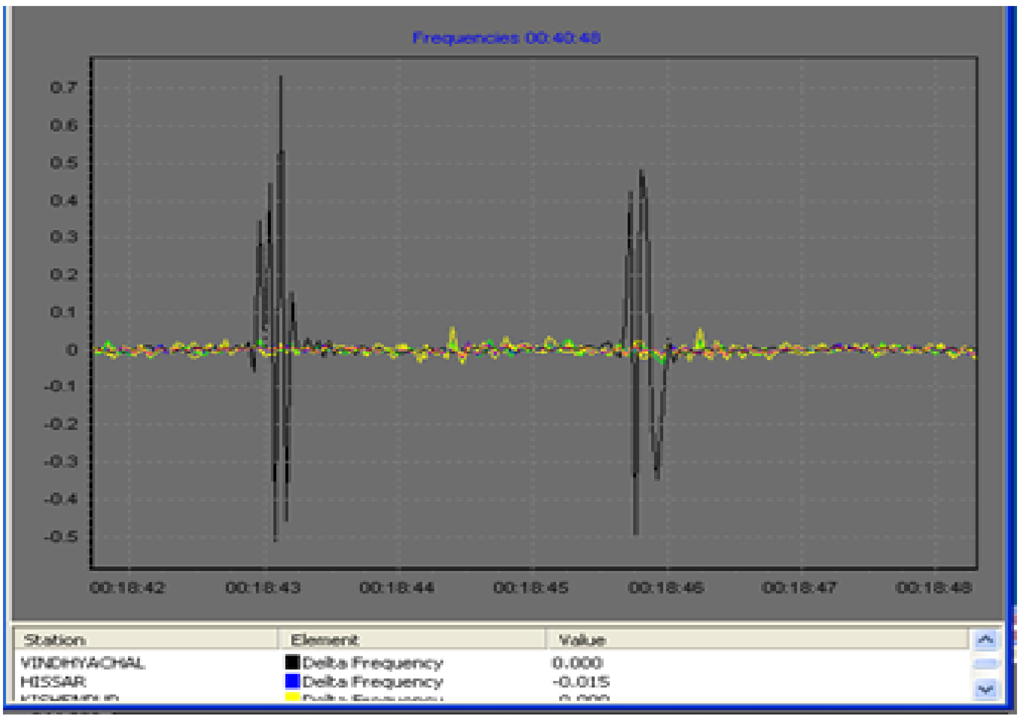

Fig 4: Auto-reclosure phenomena

6.6 Wide Area Measurement/Monitoring System (WAMS)

WAMS using Phasor measurement unit (PMUs) utilizing synchrophasor technology is an advanced measurement system that provides synchronized measurements at subsec (fraction of a second) rate. The WAMS technology provides phasor measurements over a widely spread grid. The components of WAMS consists of Phasor Measurement Units (PMUs), Phasor Data Concentrators (PDCs), Visualization aids, Application and Analysis modules, Data archiving and storage etc. The basic infrastructure of WAMS technology is PMU, wide-band communication and PDC units.

The WAMS would enable us to achieve the following benefits:

(i) With visualization of the real time angular separation between the buses and its voltages, transmission loadability in lines may be increased considerably, resulting in better utilization of the existing transmission system/assets.

(ii) Early detection of critical conditions in the grid and accordingly taking corrective operational measures to avert grid disturbance will prevent financial losses (in case of blackout).

(iii) Detection of system oscillations which cause damage to various equipments and reduces its life. Detecting such oscillations by Synchrophasor technology and tuning PSS/ voltage stabilizer to prevent oscillations would enable healthy operation of the machines for a longer period, and thus optimize the life of equipment.

(iv) Qualitative improvement may be made in the relay operation/co-ordination to identify and remove faulty elements.

(v) According to the behaviour of the real time system dynamics measured & monitored by this technology, Defense Plan/ Islanding scheme(s) can be designed to avert grid collapse.

(vi) The technology will provide more intelligence on network security and help to improve and maintain the robustness of the grid.

(vii) Objectives of secure, safe, reliable and smart grid operation will be achievable.

(viii) Economically, if the above technological and operational benefits are translated into cost, it would prevent substantial financial losses, and thus the investment for the scheme as estimated, appears to be justified.

6.7 Communication

The Communication infrastructure is critical backbone in the architecture of a WAMS system. PMU devices are distributed over a wide area, covering various locations within the boundary of a power system. The PMU devices are then connected to one or many control centers over the communication network. Fibre Optic Communication network due to its high bandwidth offer low latency for communication between PMU to PDC and PDC to PDC. The Fibre Optic terminal equipments will have the provision of in-built Ethernet port. The Ethernet port shall be used in the communication network of WAMS for dedicated channels. The existing SDH equipment will have Ethernet converter for converting from E-1 to Ethernet. The network architecture would be composed of a main optical fibre backbone connected to the substation Router/Switch. In turn, the PMU can be connected to the substation through Switch. The PMU measurements are then transferred to a PDC, which time aligns the phasors.

6.8 Unified Real Time Dynamic State Measurement (URTDSM) Scheme

6.8.1 Based on the experience gained from pilot projects and looking into the vast potential of WAMS technology for measurement of dynamic behavior of integrated power system, a comprehensive “Unified Real Time Dynamic State Measurement (URTDSM)” scheme covering substations/line at State and Inter State level has been proposed for full scale implementation of WAMS in the grid. Deployment of PDCs and PMU has been proposed as under:

1. PMU will take one(1) 3 phase voltage, two(2) three phase currents, and 8 digital signals. The PMU will provide 3 phase positive sequence voltages as magnitude and angle,3 phase positive sequence currents magnitude and angle and Frequency,. Rate of

change of frequency(df/dt) & Active and Reactive power may be derived either at PMUs or PDC from the measured values.

2. Installation of PMU at each HVDC and 400kV & above substations in State and ISTS network
3. PMU at generation switchyard at 220kV level and above
4. 220kV Inter-regional transmission lines
5. One(1) Master PDC at each SLDC and one(1) Super PDC at each RLDC/NLDC
6. New 400kV and above substations along with transmission lines coming up by 2015 time frame are considered.
7. “N-1” redundancy in the measurement through PMU i.e. each end of a line is to be monitored.

6.8.2 Hierarchal data flow architecture is proposed under the scheme. PMU data from a number of substations in a State are pooled and sent to Master PDC located at respective SLDC and in turn to Super PDC located at respective RLDC. Data from ISTS points are to be sent directly to Super PDC (SPDC) at respective RLDC. Data from each SPDC shall be sent to National PDC located at NLDC. Visualization tools are proposed at Master, Super and PDC at NLDC. User interface application software is proposed to visualize and analyze the real time phasor data. User interface will provided for configuration, monitoring and analysis of multiple synchronized phasor data on single and multiple displays. Visualization parameters will include deviation of frequency from nominal, rate-of-change of frequency exceeding a set value, voltage magnitude outside upper or lower boundaries, active or reactive power exceeding limits, voltage angle difference between selected points exceeding limits, rapid detection and display of abnormal power flows or sudden change in power flows across the lines, voltage violation nodes and areas, etc.

6.8.3 **Capacity building – Training :** As a part of capacity building activity under URTDSM, training programs are proposed. These programs shall be conducted in collaboration with Vendors and Academic Institutes for executives of State utilities, CTU, POSOCO, CEA and RPCs. Visit to utilities where WAMS are implemented world-wide are also envisaged for international exposure which would help better understanding and appreciation of the subject.

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CHAPTER – VII

7. REACTIVE POWER MANAGEMENT FOR CONTROL OF SYSTEM VOLTAGES

7.1 Participation of generations in reactive power management towards controlling voltage profile is a critical area requiring attention. Generator reactive capability is required to maintain proper system voltage levels, provide appropriate dynamic reserves and assure service reliability. However, it was generally observed that generators shy away from providing full support taking shelter under pretext of operating conditions limiting their capabilities. In this context, there is a need to validate reactive capabilities of generators in a uniform manner to arrive at realistically attainable values which should be used in planning and operation of grid. A note on reactive power capability testing of generators contributed by Shri P. Pentayya, GM, WRLDC is given in Appendix 7.1.

7.2 Voltage profile management through reactive power control by coordinated adjustment of tap ratio of generator transformers is also an important area of attention. A note on Generator tap co-ordination for reactive power control which also includes a case study for optimum setting of GT at Birsingpur units contributed by Shri P. Pentayya, GM, WRLDC is given in Appendix 7.2.

7.3 The task force recommends that full reactive capability of generators should be available for voltage regulation and there should be mechanism to compensate the generator for any loss of active generation in process of providing required reactive support.

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REACTIVE POWER CAPABILITY TESTING OF GENERATORS

Generator reactive capability is required to maintain proper system voltage levels, provide appropriate dynamic reserves and assure service reliability. This reactive capability must be validated in a uniform manner that assures the use of realistically attainable values when planning and operating the system or scheduling equipment maintenance. The validation techniques are designed to demonstrate that the stated capability for the generating equipment can be obtained for continuous operation under expected operating conditions. The validation method has to be functional and not requiring special instrumentation or procedures. Meeting these requirements, testing criteria for validating the reactive capability of generating equipment has been outlined in following paragraphs. This criteria defines the method by which ratings are to be established while recognizing the necessity of exercising judgment in their determination.

A. Scope and Objectives: The tests can be carried out for all Thermal, Gas, Hydro and nuclear Power Stations of all capacities. The Objectives are:

- enable declaration of generator reactive power capability, to meet the mandatory requirements
- ensure voltage stability
- harness benefits in the upcoming ancillary services market to sell reactive power (including sale of dynamic reserves)
- empower, enlighten and boost the confidence of generating station operators
- safeguard generators from unsafe operating conditions

B. Regulatory Provisions : The gross and net reactive capability will be determined within the power factor range at which the generating equipment is normally expected to operate as per the following standards / regulations:

IEGC Part-6; Section 6.6 – Relevant extracts

(6) The ISGS and other generating stations connected to regional grid shall generate/absorb reactive power as per instructions of RLDC, within capability limits of the respective generating units, that is without sacrificing on the active generation required at that time. No payments shall be made to the generating companies for such Var generation/absorption.

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CEA Technical Standards for Connectivity to Grid, Regulations 2007 – Relevant extracts

Part-II

Grid Connectivity Standards applicable to Generating Units

1. New Generating Units

(1) The excitation system for every generating unit :-

(a) Shall have state of the art excitation system;

(b) Shall have Automatic Voltage Regulator (AVR). Generators of 100MW rating and above shall have AVR with digital control and two separate channels having independent inputs and automatic changeover; and

(c) The AVR of generator of 100MW and above shall include Power System Stabilizer (PSS)

(6) Generating Units located near load center, shall be capable of operating at rated output for power factor varying between 0.85 lagging (over-excited) to 0.95 leading (under-excited) and Generating Units located far from load centers shall be capable of operating at rated output for power factor varying between 0.9 lagging (over-excited) to 0.95 leading (under-excited). The above performance shall also be achieved with voltage variation of ± 5% of nominal, frequency variation of +3% and -5% and combined voltage and frequency variation of ± 5%. However, for gas turbines, the above performance shall be achieved for voltage variation of ± 5%.

CEA Regulations -2010 on Technical Standards for Construction of Electrical Plants and Electrical Lines
Extracts from Chapter-II, PART-B of the regulations:

(g) *Excitation System*

(i) Suitable generator excitation system as well as automatic voltage regulator (AVR) shall be provided with the generator as per Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007. Power system stabilizer (PSS) shall be provided in AVR for generator of 100MW and higher rating.

(ii) The rated current of the excitation system shall be at least 110% of the machine excitation current at the rated output of the machine. The rated voltage shall be at least 110% of the machine excitation voltage.

C. Specific Requirements

(a) Scheduling of any test shall first be coordinated with the system operator. System operators will assist in determining the amount of variation from scheduled voltage that is acceptable. When scheduling, the season and time of day that are conducive to the required Reactive Power capabilities shall be considered.

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(b) The overexcited reactive capability validation shall be conducted for a minimum of two hours and leading (under excited) reactive power test for at least one hour. Data for the under-excited reactive capability validation may be recorded as soon as a limit is encountered. Steady Real and Reactive Power output should be maintained during the data collection interval. Data should be collected with all auxiliary equipment needed for normal operation in service.

(c) For hydrogen-cooled generators, the hydrogen pressure should be at the maximum operation pressure. If the maximum designed hydrogen pressure cannot be maintained for normal operation, then the reason for this condition shall be documented and the appropriate generator capability curve shall be used. Additional engineering evaluation may be required to ensure expected reactive capabilities are achievable.

(d) When the maximum reactive power capabilities are validated, the reactive power at the generator terminals i.e. the generator step-up transformer (GT) primary (LV side, after auxiliaries), and the GT secondary (HV side) shall be documented. The corresponding MW outputs shall also be recorded.

(e) During the validation, the scheduled and actual voltages at the system bus and the generator terminals shall also be recorded. In addition, the existing GT, Unit Auxiliary Transformer (UAT), Station Transformer(ST) tap setting shall be documented.

(f) Reactive power testing for both over-excitation and under-excitation should be done at rated load and at reducing loading levels.

(g) AVR should be in service

(h) If GT, ST, UAT taps are off-nominal, test should be repeated after changing the taps (may be when the unit is under outage). The optimization of tap settings need to be studied in the off line and the tests to be carried out preferably for these optimized settings.

(i) It is to be ensured that over-excitation trip (V/f) does not occur until the generator terminal voltage is above 108%. During the test, it is expected that generator terminal voltage may reach 105% and this should not cause tripping through V/f protection.

(j) The load-drop compensation setting to be indicated.

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D. Detailed Procedure :

In order to obtain the steady state MVAR capability of a generating unit, perform **(a) Lagging Reactive Capability test;** and **(b) Leading Reactive Capability test**. Operating conditions should be as close to normal as practicable, including loading, unit temperatures (field, etc.) and pressures (hydrogen, boiler, etc.). Tests should be performed during periods of operation which maximize the MVAR output of the machine. Therefore, testing should be performed during a period when system voltage is most advantageous to yield these results. When possible other synchronous machines or power system components should be used, to obtain the most advantageous terminal voltage during these tests.

Lagging Reactive Capability Test

(1) While operating in a steady state mode at near rated output, raise excitation in automatic voltage control mode until one of the following conditions occurs:
- (a) The 100% MVA rating of the machine is reached (reach capability curve);
- (b) Rated field current or field voltage is reached;
- (c) Terminal voltage limit is reached (105-110%, depending on unit);
- (d) Generator temperature limits are reached (either stator winding or field winding);
- (e) The maximum/over excitation limiter is reached/alarms;
- (f) Maximum auxiliary bus voltage is reached.

2) Hold unit at this level for a minimum of 15 minutes (30 minutes is a preferable duration) or till the temperature stabilizes then take the following measurements.
- a) Gross MW output at both test points;
- b) Gross MVAR output limits of generator reached in tests A and B;
- c) Generator terminal voltage at maximum positive and negative MVARs;
- d) Actual field current at both test points;
- e) Machine MVA rating, both original nameplate rating and tested rating, if different; Generator rated terminal voltage and rated field current;
- f) Auxiliary bus voltage at minimum and maximum points;
- g) Ambient temperature before conducting the lagging and leading tests

In addition to values being reported, the following machine parameters may be recorded for use during future testing
- Generator field voltage;
- Rotating exciter field current and voltage (if appropriate) ;
- Generator stator currents;
- Field current.

Repeat the test at reduced loading (MW) level

Appendix-7.1

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Leading Reactive Capability Test

(1) While operating in a steady state mode at almost rated load, lower excitation in the automatic voltage control mode until one of the following conditions occurs:
   (a) Under Excitation Limiters (UELs) are activated;
   (b) 100% MVA rating is reached;
   (c) Generator temperature limits are reached(either stator or field);
   (d) Minimum auxiliary bus voltage is reached;
   (e) Minimum terminal voltage is reached.

(2) Take following measurements

a) Gross MW output at both test points;
b) Gross MVAR output limits of generator reached in tests A and B;
c) Generator terminal voltage at maximum positive and negative MVARs;
d) Actual field current at both test points;
e) Machine MVA rating, both original nameplate rating and tested rating, if different; Generator rated terminal voltage and rated field current;
f) Auxiliary bus voltage at minimum and maximum points;
g) Ambient temperature before conducting the lagging and leading tests

In addition to values being reported, the following machine parameters may be recorded for use during future testing

- Generator field voltage;
- Rotating exciter field current and voltage (if appropriate) ;
- Generator stator currents;
- Field current.

E. PRECAUTIONS

I. Ensure that controls such as volts/hertz limiters and UELs are coordinated and at proper settings prior to testing to prevent unnecessary operation of volts/hertz relays or loss of excitation relays.

II. Determine first the expected MVAR limiting point, and do not proceed past that point. If this point is reached without activating the UELs/MELs (minimum excitation limiters) return to normal excitation and determine why the limiter is not functioning. Also, ensure that all transformer taps throughout the power plant are coordinated so the terminal voltage can reach the minimum (90-95%, depending on unit) without causing problems to the auxiliary power further in the plant.

III. Some excitation systems transfer to manual or backup controllers if over-excitation is detected. If this happens, record the level at which it occurs and reset the control to automatic before placing the unit back in normal service. If the machine trips for any reason during these tests, specify what tripped and why it tripped. Correct the problem and retest the unit.

F. Commercial conditions

(a) All efforts should be made to carry out the test during the period when generation scheduled from the station is less than its declared capability (DC). However, any deviations of actual station generation (ex-bus) w.r.t the schedule due to the testing of the identified unit to be taken care of by making schedule station generation = actual station generation in order to insulate the concerned generating station from being subjected to any financial penalties under the existing UI mechanism .

(b) The scheduled drawal of the beneficiaries of the station should be deemed to have been revised accordingly, during the period of test.

Appendix-7.2
(Page 1/4 of Appendix)

GENERATOR TAP CO-ORDINATION FOR REACTIVE POWER CONTROL

As per clause 9.9 of the recommendations of the Committee for analysis of grid disturbances in July'12,

Quote

9.9 Optimum utilization of available assets

9.9.1 The regulatory provisions regarding absorption of reactive power by generating units needs to be implemented.

Unquote

It was observed that coordinated efforts by all generators by optimizing the tap settings of Generator Transformer(GT), Station Transformer(ST) and Unit Auxiliary Transformer(UAT) is required to contain the high voltage of buses with comparatively high fault level. Under low voltage conditions, GT tap optimization can prevent voltage collapse by maximizing MVAR generation.

As a trial basis, studies were done at WRLDC for optimization of GT tap setting at NSPCL(2x250MW) units in Western Region.

The GT, ST and UAT tap settings of 250MW generator at NSPCL is given below:-

Generator transformer-420/16.5kV,315MVA				Unit Auxiliary Transformer-16.5/6.9kV, 50MVA		
Tap position	HV	LV		Tap positi	HV	LV
1	441	16.5		1	17.325	6.9
2	430.5	16.5		2	16.9125	6.9
3	420	16.5		3	16.5	6.9
4	409.5	16.5		4	16.0875	6.9
5	399	16.5		5	15.675	6.9

Station Transformer 220/6.9kV , 50MVA					
Tap position	HV	LV	Tap position	HV	LV
1	242	6.9	9	220	6.9
2	239.25	6.9	10	217.25	6.9
3	236.5	6.9	11	214.5	6.9
4	233.75	6.9	12	211.75	6.9
5	231	6.9	13	209	6.9
6	228.25	6.9	14	206.25	6.9
7	225.5	6.9	15	203.5	6.9
8	222.75	6.9	16	200.75	6.9
			17	198	6.9

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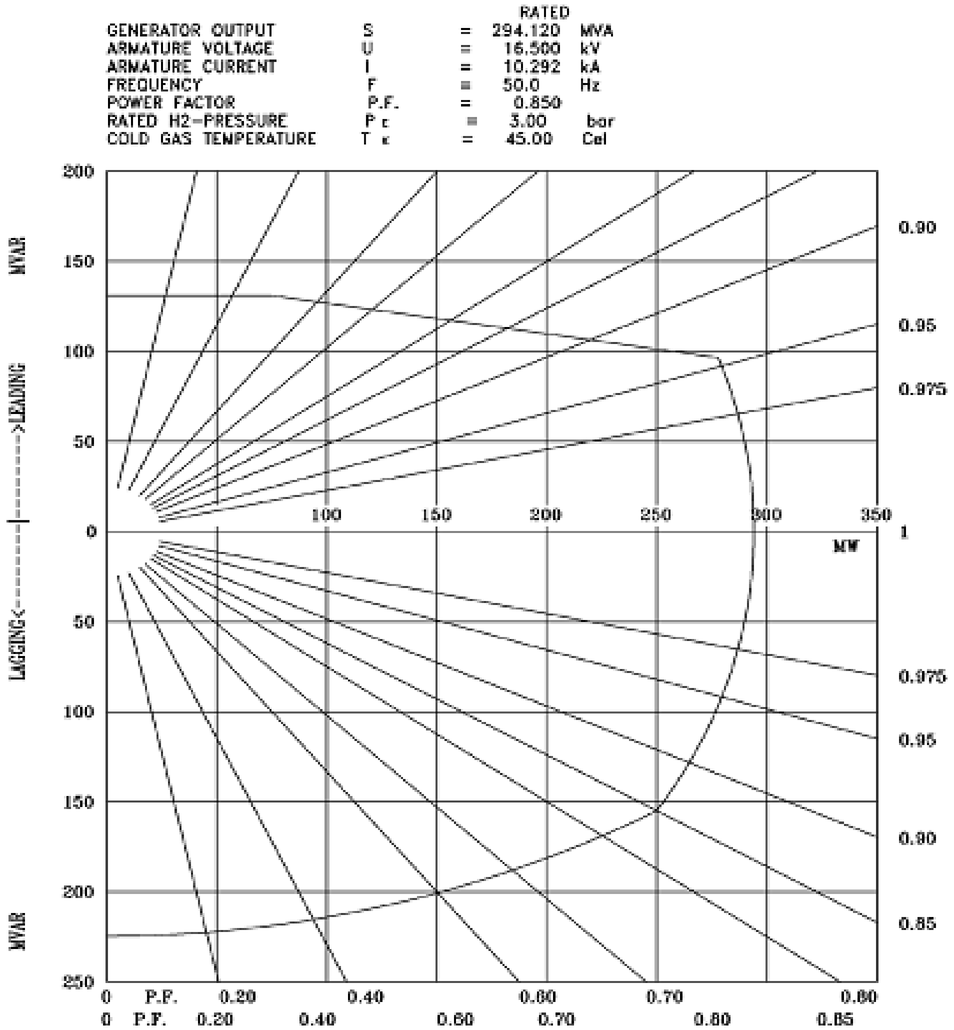
The capability curve of NSPCL unit (250MW) is given below:-



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Results of optimization studies for NSPCL, done for taps of all the transformers, is given below:-

Tap positon			Reactive power (MVAR)	Voltage(kV)	Remark
GT	ST	UAT	Generator (250MW)	400kV NSPCL	
4	6	3	-124.6	401.42	Maximum absorption of reactive power by generators
3	6	3	-15.8	403.34	Present tap setting
2	6	4	99	405.2	Maximum generation of reactive power by generators

- For present GT tap setting(3),thev generator absorbs only 16MVAR while increasing GT tap position to 4 generator absorbs 125MVAR resulting in decrease of 2kV voltage at NSPCL ie (125-16)*400/19927~ 2kV
- Fault MVA at NSPCL and Raipur are 19927MVA and 25630MVA

It was observed that by changing the present GT tap setting (3) to (4) , MVAR absorption changed from 16MVAR to 125MVAR resulting in drop in voltage of 2kV at NSPCL and 1 kV at Raipur. Probably such isolated optimization may not bring much impact, but co-ordinated efforts by all generators (ISGS/State) would bring better impact on voltage control.

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GT tap changing studies at Birsinghpur units (4x210+1x500MW)

The GT tap settings of Birsinghpur units are given in table below:-

GT Tap changing details for 400kV birsingpur S/S

Generator Transformer at Birsingpur	Total tap positions	Normal Tap Positon	Present Tap Position	HV Voltage (KV)	LV Voltage (KV)	MVA	Step Size
GT-unit 1 (210MW)	5	3	4	240	17.5	250	0.025
GT-unit 2 (210MW)	5	3	4	240	17.5	250	0.025
GT-unit 3 (210MW)	5	3	4	240	17.5	250	0.025
GT-unit 4(210MW)	5	3	4	240	17.5	250	0.025
GT-unit 5 (500MW)	9	5	6	420	21	600	0.025

Studies were done changing the GT tap setting to find out optimum tap. Results are given below:-

Reactive power absorbtion with tap position varied for GT-5 and other GT's at normal tap position

Tap position of GT-5	GT-5	Tap position of GT 1-4	GT-1	GT-2	GT-3	GT-4	Voltages	
							400kV Birsingpur	220kV Birsingpur
6	-200	3	-7.6	-7.6	-7.6	-7.6	411.3	220.8
5	-157.6	3	-10.1	-10.1	-10.1	-10.1	413	221
4	-77	3	-15.3	-15.3	-15.3	-15.3	416.5	221.7
3	2.1	3	-20.3	-20.3	-20.3	-20.3	419.7	222.2
2	79.8	3	-25	-25	-25	-25	422.8	222.7
1	156	3	-25.4	-25.4	-25.4	-25.4	425.6	223.2

Reactive power absorbtion with tap position varied for GT-1 to GT-4 and GT's at tap position 6

Tap position of GT-5	GT-5	Tap position of GT 1-4	GT-1	GT-2	GT-3	GT-4	Voltages	
							400kV Birsingpur	220kV Birsingpur
6	-200	1	32.8	32.8	32.8	32.8	416.4	227.2
6	-200	2	12.7	12.7	12.7	12.7	413.9	224
6	-200	3	-7.6	-7.6	-7.6	-7.6	411.3	220.8
6	-200	4	-34.2	-34.2	-34.2	-34.2	409.2	218
6	**-200**	**5**	**-58.1**	**-58.1**	**-58.1**	**-58.1**	406.9	215

It was observed that the normal tap setting is 5 and the unit-5 (500MW) is absorbing maximum MVAR at tap position 6. The 210MW units absorb maximum MVAR at tap 5. Therefore it was confirmed from studies that the present tap setting adopted by 500MW generator is optimum and suggested to continue the same. 210MW units connected 220kV Birsinghpur would absorb maximum MVAR if the GT tap is changed from 3 to 5.

It has been observed from the data of Birsighpur generators that all GT taps are kept at a higher turns ratio than the nominal value. With this, the generator terminal voltage remains close to nominal voltage. However this is leading to high voltages at EHV level as the generators do not absorb adequate reactive power as per their capability curve.

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CHAPTER –VIII

8. TUNING OF POWER ELECTRONIC DEVICES

8.1 The Indian power network consists of several HVDC links and Flexible AC Transmission System (FACTS) devices installed at various points of time. A list of HVDC and FACTS devices in Indian System as at present is given below:

HVDC Bi-pole lines

- Rihand - Dadri 1500 MW HVDC bipole
- Chandrapur- Padghe 1500 MW HVDC Bipole
- Talcher - Kolar 2500 MW, HVDC Bipole
- Ballia - Bhiwadi 2500 MW Bipole
- Mundra(Adani) - Mahendragarh 2500 MW Bipole

HVDC back-to-back links

- Vindhyachal 2 x 250,
- Chandrapur 2x500MW
- Gazuwaka 2 x 500 MW
- Sasaram 1 x 500 MW

FACTS Devices

- Kanpur 2x±140MVAR SVC
- TCSC in the Raipur - Rourkela 400 kV double-circuit line at Raipur end
- TCSC's on the Tala - Purnea - Muzaffarpur- Gorakhpur 400 kV double circuit lines at Purnea and Gorakhpur ends

All the above devices have controllers embedded in them to take advantage of their capability to modulate parameters like active power flow, frequency or impedance depending on their nature and location to assist in stabilising the network during disturbed conditions. Controllers of the devices were tuned as per results of simulation studies during the project implementation phase, prior to their commissioning based on network configuration as envisaged at that time. Projected network data and inputs provided at that stage could have been adequate to cover their optimum performance for approximately a 5 year time frame. Re-tuning of some of the controllers has been done on specific requirement. However, while the Indian power network has been expanding continuously and at a rapid pace, no comprehensive retuning of HVDC/FACTS controllers has been undertaken.

8.2 Grid expansion on account of increase in load and generation and the consequent expansion of the transmission, sub-transmission and distribution systems at all voltage levels and also the increase in reactive compensation levels both shunt reactive and capacitive, has led to substantial changes in the power flow patterns, voltage profile in the steady state and also the dynamic characteristics and behavior. The changes in the steady state nature of the network are usually constantly kept track of as part of the regular planning studies as part of network expansion analyses which include addition of transmission lines and the associated shunt reactive compensation. These analyses are any way required to look for any power flow constraints under normal and for 'N -1' conditions. These studies also give a picture of the system voltage profile and thus adequacy of reactive compensation levels for peak and off-peak conditions.

8.3 Along with this expansion also taking place constantly is the dynamic behavior of the system, whose characteristics also need to be analysed particularly in terms of local and inter-area oscillations, their magnitude, frequency and damping patterns. Although some of these do not manifest under normal conditions their presence becomes predominant and could be significant under steady-state overload conditions and also under disturbance situations initiated by major tripping of generation or transmission elements with or without faults. When disturbances occur the post disturbance recovery of the system (could be also post fault recovery) is significantly dependent on the capability of the system to quickly damp out the oscillations that are initiated. Any poorly damped or persistent oscillations can be harmful for the system recovery and if not quickly controlled, could lead to larger problems or even the need for isolation of parts of the network.

8.4 It is pertinent to point out that the controllers of HVDC and FACTS devices were tuned as per results of simulation studies during the project implementation phase, prior to their commissioning based on the projected network data and inputs provided at that stage which could have been adequate to cover their optimum performance for approximately a 5 year time frame. Some of these systems like the 2 x 250 MW, Vindhyachal back-to-back link and the Rihand - Dadri 1500 MW HVDC bipole have been tested and commissioned in the late 80's/ early 90's. The AC networks in which they are operating today are entirely different from those that were studied/ simulated for. Accordingly, the system level controllers like the AC system stabilisation control, AC Line Load controls and frequency controls would be sub - optimally tuned with reference to the present day network. For example the following network characteristics have definitely changed:

- Natural frequency of network (reduces with increasing network size)
- The power number and short circuit levels (this goes up with higher network size)
- Local and inter-area/ region oscillation modes and frequencies

8.5 Further the HVDC and other FACTS systems which were installed progressively later on were/ would have been tuned corresponding to the network status available and predicted during their installation time frames. For example we have the following plants:

- 2x500MW Chandrapur HVDC back-to-back - commissioned in 1998-99
- Chandrapur- Padghe 1500 MW HVDC Bipole - commissioned in 1999
- Talcher - Kolar 2500 MW, HVDC Bipole - commissioned in 2002
- Ballia - Bhiwadi 2500 MW Bipole - commissioned in 2010 -12
- Mundra - Mahendragarh 2500 MW Bipole - commissioned in 2011

8.6 Apart from the above HVDC links, we have the following power electronics enabled FACTS devices in the network.

- 2x +/- 140MVAR SVC at Kanpur 400kV s/s, commissioned in 1992
- The TCSC in the Raipur - Rourkela 400 kV double-circuit line, at Raipur end, commissioned in 2004
- TCSC's on the Tala - Purnea - Muzaffarpur- Gorakhpur 400 kV double circuit lines at Purnea and Gorakhpur ends, commissioned in 2005 -06

8.7 Thus a situation has emerged wherein there are several power electronic devices placed in the system which have been tuned for various scenarios/ time frames corresponding to different stages of growth of the networks. To add to the above, the network growth and expansion philosophy has undergone a change with 3 of the asynchronous networks i.e. the **Nor**thern, **E**astern-cum-North Eastern and **W**estern regional networks (**NEW** grid) becoming progressively synchronous from 2004 -05. Today only the Southern regional network remains asynchronous. These merging of networks cause a big step change to the characteristics like, natural frequency of oscillation, modes and overall behavior.

8.8 Another feature is the accelerated growth of the networks compared to the earlier years which means the newer devices or plants being installed with tuned controllers will have a shorter time frame with respect to their validity in terms of expected support for the network stabilising or damping performance. The net result is that at any given point of time we have a set of plants with various levels of damping capability which might not only be sub-optimal but also may not be coherent or mutually supportive in overall stabilising the system. (For example the TCSC on the Raipur _ Rourkela 400 kV line when installed, was on the only available inter-regional tie line between the Eastern and Western regions - today there are more parallel circuits which makes the controller behavior different)

8.9 Installation of control devices progressively in the network will also lead to interaction of different influences in the power system. As each equipment has its own controller with its optimised control strategy, with even different objective functions, their combined influence in a growing network could turn out to be different during disturbances. In such situations a global optimisation of the control functions may be required to ensure/enhance overall system stability.

8.10 Apart from the above we have several Power System Stabilisers (PSS) as part of the generators installed in the network. Although these are localised devices they are nevertheless critical for damping the local area oscillations and imparting stability to the networks. Their correct tuning will enhance the capability of the other HVDC and FACTs controllers in imparting overall/ inter-area stability in an effective manner.

8.11 **Need to constantly review and re-study the network together with the Power Electronic devices**.

8.11.1 In view of the foregoing, it is imperative that a systematic methodology for reviewing the effectiveness of all extant controllable plants/devices in the network, be put in place - this study or review being undertaken every 3 - 4 years with their results being implemented immediately following the review and approval of the findings so that the newly tuned controller parameters remain valid at least for the next 3 - 4 year time frame. This would then ensure better stability and security of the system at any point of time.

8.11.2 As these studies are intricate requiring experience of different philosophies and involves specialised dynamic modelling, the review and study may be entrusted to a reputed independent agency while the implementation of the tuning in the respective plants be entrusted to the respective Original Equipment Manufacturers/suppliers under a suitable AMC or Service contract.

8.11.3 The costs incurred for the studies and retuning effort would be only a fraction of the costs expended on the plants and thus the network would get a much higher return in terms of stable performance

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CHAPTER –IX

9. PROTECTION SYSTEM AUDIT AND RELAY SETTINGS

9.1 The Enquiry Committee under Chairman, CEA which analyzed the grid disturbance recommended an extensive review and the audit of the protection system. The Task Force also noted from the Enquiry Committee report that one of the factors that led to the initiation of the grid disturbance on 30th & 31st July 2012 was the tripping of lines in the major inter-regional corridors in a mal operation of distance relay known as 'Load Encroachment' which may happen even if there is no fault in the nearby transmission system, and may occur when the line carries very heavy load.

9.2 It was flagged during the first meeting of the Task Force that though there is a CBIP manual delineating the philosophy for coordinated operation of the relay system, practice adopted in protection coordination of transmission lines, transformers and generators was at variance with respect to CBIP manual and it also varied from utility to utility. It was, therefore, felt by the Task Force that a separate Sub-Committee constituting Engineers from industry and utilities who are specifically dealing with protection/relay issues should analyze the practice being adopted by the various utilities and evolve a common philosophy so that the settings of the various relays are suitably coordinated and the protection system operates in an efficient manner.

9.3 Accordingly, a Protection Sub-committee comprising engineers from CTU, STU, NTPC, Tata Power, ABB and IPPs was constituted to deliberated on the issues concerning protection system. The sub-committee was also mandated to finalise a format for reporting of audit of relay and protection system on periodic basis and also carry out a case study of setting of relays for a particular topology and also for addition/modification of topology so that all utility engineers carry out such exercise in future before setting of relays before commissioning of new transmission lines or when the network topology changes due to addition of lines or LILO of existing lines at new sub-stations.

9.4 The sub-committee framed a questionnaire and had it sent to all the utilities through RPC. The reply received from utilities indicated that most of them were adopting different norms for relay setting even though a CBIP publication for relay setting exists. The sub-committee deliberated in detail the methodology to be adopted for relay setting and the setting criteria for 220kV, 400kV and 765kV transmission lines (both uncompensated and series compensated) and has given recommendations on the settings to be adopted. The recommendations are based on guidelines given in following documents:

- CBIP Publication no 274: Manual on Protection of Generators, Generator Transformers and 220kV and 400kV Networks
- CBIP Publication no 296: Manual on Reliable Fault Clearance and Back-Up Protection of EHV and UHV Transmission Networks
- CIGRE WG B5.10, 411: Protection, Control and Monitoring Of Series Compensated Networks
- CIGRE WG 34.04 ; Application Guide on Protection Of Complex Transmission Network Configurations

9.5 RECOMMENDED METHODOLOGY FOR RELAY SETTING :

Recommended methodology for relay settings for transmission lines is given in Appendix-9.1 and Appendix-9.2. Protection audit data format and check list have also been prepared by the Protection sub-committee under Task Force to enable audit of practices followed in protection application &criteria used for setting calculations in 220kV, 400kV & 765kV substations. It aims to cover the entire fault clearance system used for overhead lines & cables, power transformers, shunt reactors and bus bars in a substation. The objective is to check if the fault clearance system provided gives reliable fault clearance. The protection audit data format and check list are given respectively in Appendix 9.3 and 9.4

The sub-committee is in process of carrying out a case study for calculations of relay settings both for present network conditions and for change/modification in the network topology in future and a report thereon will be submitted shortly. This case study may serve as model for calculation of relay settings in future by various utilities.

9.6 **ACTION PLAN:** The Task Force is of the view that for proper protection coordination, all utilities should follow the guide lines and get their protection system audited from time to time as per the recommended methodology for relay settings, data format and checklist as recommended by the Protection Sub-Committee. The Task Force has also felt strong need for the following:

- Creating and maintaining data base of relay settings. Data regarding settings of relays in their network should be compiled by the CTU and STUs and furnished to the RLDC and SLDC respectively and a copy should also be submitted to RPC for maintaining the data base.
- Mandating periodic audit and reporting through regulations by CERC and SERCs by specifying this in Grid Codes.
- Appointing an Internationally reputed consultant to carry out studies to determine the relay settings for the complete network and also carry out the settings at site in coordination with the CTU and STU's with time bound target. So as to complete the comprehensive exercise within the next one year.
- Periodic review of protection coordination and relay settings to take care of changes in network topology due to addition of new system elements – generating units, transmission lines, etc. The Regional Power Committee which is mandated to discuss issues relating to coordination of grid operation among the various utilities in the Region should on a quarterly basis review the protection & relay coordination issues and ensure carrying out of the necessary modifications in the relay settings.

9.7 Task Force has also observed that many of the utilities do not possess well trained and dedicated group to carry out studies for calculations for relay settings. The Task force strongly recommends that a dedicated group is required to be constituted and trained in all Utilities to carry out computer aided studies for relay settings. It also recommends that for settings of critical transmission lines and corridors the relay setting calculations be validated by simulations on the Real time digital simulator (RTDS) available with CPRI and PGCIL.

9.8 **PROTECTION SYSTEM MANAGEMENT**:

During the discussions and interactions with the various stake holders of the protection system, it was strongly felt by the Protection Sub-committee members that in addition to technical issues related to protection, the management issues related to protection system need to be addressed. In order to comprehensively address the protection issues in the utilities, following are the recommendations.

1. **ESTABLISHING PROTECTION APPLICATION DEPARTMENT:**
   1.1. It is recommended that each utility establishes a protection application department with adequate manpower and skill set.
   1.2. The protection system skill set is gained with experience, resolving various practical problems, case studies, close interaction with the relay manufactures and field engineers. Therefore it is proposed that such people should be nurtured to have a long standing career growth in the protection application department.

2. **RELAY SETTING CALCULATIONS**
   2.1. The protection group should do periodic relay setting calculations as and when necessitated by system configuration changes. A relay setting approval system should be in place.
   2.2. Relay setting calculations also need to be revisited whenever the minor configuration or loading changes in the system due to operational constraints. Feedback from the field/substations on the performance of the relay settings should be collected and settings should be reviewed and corrected if required.

3. COORDINATION WITH SYSTEM STUDY GROUP, SYSTEM PLANNING GROUP AND OTHER STAKEHOLDERS

3.1. It is recommended that each utility has a strong system study group with adequate manpower and skill set that can carry out various system studies required for arriving at system related settings in protection system in addition to others studies.

3.2. The protection application department should closely work in co-ordination with the utility system study group, system planning group, the system operation group.

3.3. Wherever applicable, it should also co-ordinate and work with all power utilities to arrive at the proper relay setting calculations taking the system as a whole.

3.4. The interface point relay setting calculations at CTU-STU, STU-DISCOMS, STU-GEN Companies, CTU-GEN Companies and also generator backup relay setting calculations related to system performance should be periodically reviewed and jointly concurrence should be arrived. The approved relay settings should be properly document.

3.5. Any un-resolved issues among the stakeholders should be taken up with the RPC and resolved.

4. SIMULATION TESTING FOR CHECKING DEPENDABILITY AND SECURITY OF PROTECTION SYSTEM FOR CRITICAL LINES AND SERIES COMPENSATED LINES

4.1. Committee felt that even though Real Time Digital Simulation (RTDS) and other simulation facilities are available in the country, use of the same by the protection group is very minimum or nil.

4.2. It is recommended that protection system for critical lines, all series compensated lines along with interconnected lines should be simulated for intended operation under normal and abnormal system conditions and tested for the dependability and security of protection system. The RTDS facilities available in the country like at CPRI, POWERGRID and other places should be made use of for this purpose.

4.3. The network model should be periodically updated with the system parameters, as and when network changes are incorporated.

5. ADOPTION OF RELAY SETTING AND FUNCTIONAL VERIFICATION OF SETTING AT SITE

5.1. Protection application department shall ensure through field testing group that the final relay settings are exactly adopted in the relays at field.

5.2. There should be clear template for the setting adoption duly authorized and approved by the field testing in charge.

5.3. No relay setting in the field shall be changed without proper documentation and approval by the protection application department.

5.4. Protection application department shall periodically verify the implemented setting at site through an audit process.

6. STORAGE AND MANAGEMENT OF RELAY SETTINGS

6.1. The committee felt that with the application of numerical relays, increased system size & volume of relay setting, associated data to be handled is enormous. It is recommended that utilities shall evolve proper storage and management mechanism (version control) for relay settings.

6.2. Along with the relay setting data, IED configuration file should also be stored and managed.

7. ROOT CAUSE ANALYSIS OF MAJOR PROTECTION TRIPPING (MULTIPLE ELEMENT OUTAGE) ALONGWITH CORRECTIVE & IMPROVEMENT MEASURES

7.1. The routine tripping of transmission lines, transformers and generating units are generally analysed by the field protection personnel. For every tripping, a trip report along with associated DR and event logger file shall be generated. However, for major tripping in the system, it is recommended that the protection application department shall perform the root cause analysis of the event.

7.2. The root cause analysis shall address the cause of fault, any mal-operation or non-operation of relays, protection scheme etc.

7.3. The root cause analysis shall identify corrective and improvement measures required in the relay setting, protection scheme or any other changes to ensure the system security, reliability and dependability of the protection system.

7.4. Protection application group shall keep proper records of corrective and improvement actions taken.

8. PERFORMANCE INDICES: DEPENDABILITY & SECURITY OF PROTECTION SYSTEM

8.1. The committee felt that key performance indices should be calculated on yearly basis on the dependability and security of protection system as brought out in CBIP manual.

9. PERIODIC PROTECTION AUDIT

9.1. Periodic audit of the protection system shall be ensured by the protection application team.

9.2. The audit shall broadly cover the three important aspect of protection system, namely the philosophy, the setting, the healthiness of Fault Clearing System.

10. REGULAR TRAINING AND CERTIFICATION

10.1. The members of the protection application team shall undergo regular training to enhance & update their skill sets.

10.2. The training modules shall consist of system studies, relaying applications, testing & commissioning

10.3. Certification of protection system field engineer for the testing & commissioning of relay, protection scheme is strongly recommended.

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RECOMMENDED METHODOLOGY FOR RELAY SETTINGS OF UNCOMPENSATED TRANSMISSION LINES

1. *ZONE-1 REACH SETTING:*

Zone-1: To be set to cover 80% of protected line length. Set zero sequence compensation factor KN as (Z0 – Z1) / 3Z1.

Where:

Z1= Positive sequence impedance of the protected line

Z0 = Zero sequence impedance of the protected line

Note: With this setting, the relay may overreach when parallel circuit is open and grounded at both ends. This risk is considered acceptable.

2. *ZONE-2 REACH SETTING:*

Zone-2: To be set to cover minimum 120% of length of principle line section. However, in case of double circuit lines 150% coverage must be provided to take care of under reaching due to mutual coupling effect. Set K_N as $(Z_0 – Z_1) / 3Z_1$.

The 150% setting is arrived at considering an expected under reach of about 30% when both lines are in parallel and a margin of 20%. The degree of under reach can be calculated using equation $K_{0M} / 1+K_0$ $\Delta Z = \frac{K_{om}}{1+K_o}$ Where $K_{0M} = Z_{0M}/ 3Z_1$ and $K_0 = (Z_0 – Z_1) / 3Z_1$. $K_o = \frac{Z_o - Z_l}{3Z_l}$ It is recommended to check the degree of under reach due to mutual coupling effect to be sure that setting of 150% is adequate.

Sometimes impedance so selected might enter the next voltage level. However, un-selectivity in the Zone-2 grading is generally not to be expected when in-feeds exist at the remote sub-station as they reduce the overreach considerably.

This holds good for majority of the cases, however, for certain cases, where in-feed from other feeder at the local bus is not significant, Zone-2 of remote end relay may see the fault at lower voltage level. Care has to be taken for all such cases by suitable time delay.

3. *ZONE-3 REACH SETTING:*

Zone-3 distance protection can offer time-delayed remote back-up protection for an adjacent transmission circuit. To achieve this, Zone-3 distance elements must be set according to the following criteria where possible.

Zone-3 should overreach the remote terminal of the longest adjacent line by an acceptable margin (typically 20% of highest impedance seen) for all fault conditions.

Set K_N as $(Z_0 – Z_1) / 3Z_1$.

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However, in such case where Zone-3 reach is set to enter into next lower voltage level, Zone-3 timing shall be coordinated with the back-up protection (Directional over current and earth fault relay) of power transformer. Where such coordination cannot be realized, it is recommended to carry out simulation studies for relay reach & time coordination and suitable solution may be devised. Some of the typical solution can be like application of back up distance protection for power transformer, duplicated protection for downstream 220kV feeders or special protection scheme logic. Similar issues, if encountered for Zone-2 reach setting, should also be addressed in the above manner.

4. ***RESISTIVE REACH SETTING***

For phase to ground faults, resistive reach should be set to give maximum coverage considering fault resistance, arc resistance & tower footing resistance. It has been considered that ground fault would not be responsive to line loading.

For Zone-1 resistive reach, attention has to be given to any limitations indicated by manufacturer in respect of resistive setting vis-a-vis reactance setting to avoid overreach due to remote in-feed. *It is recommended to study the impact of remote end in-feed for expected power flow & fault resistance on the extent of overreach*. *This is particularly important for short lines.*

In case of phase to phase fault, resistive reach should be set to provide coverage against all types of anticipated phase to phase faults subject to check of possibility against load point encroachment considering minimum expected voltage and maximum load expected during short time emergency system condition.

It is recommended that all the distance relays should have quadrilateral / polygon characteristic. For relays having Mho characteristic, it is desirable to have load encroachment prevention characteristic or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a line during emergency system condition, following criteria may be considered for deciding load point encroachment:

- Maximum load current (Imax) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15minutes rating of the transmission facility).
- Minimum voltage (Vmin) to be considered as 0.85pu (85%).

Due to in-feeds, the apparent fault resistance seen by relay is several times the actual value. This should be kept in mind while arriving at resistive reach setting for Zone-2 and Zone-3.

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5. *ZONE-2 TIMER SETTING:*

A Zone-2 timing of 0.35 seconds (considering LBB time of 200mSec, CB open time of 60ms, resetting time of 30ms and safety margin of 60ms) is recommended. However, if a long line is followed by a short line, then a higher setting (typically 0.6second) may be adopted on long line to avoid indiscriminate tripping through Zone-2 operation on both lines.

For special cases, following shall be the guiding philosophy:

Since Zone-2 distance protection is set to overreach the circuit it is intended to protect, it will also be responsive to faults within adjacent power system circuit. For this reason the time delay for Zone–2 back-up protection must be set to coordinate with clearance of adjacent circuit faults, within reach, by the intended main protection or by breaker fail protection.

The following formula would be the basis for determining the minimum acceptable Zone-2 time setting:

$$t_{Z2} > t_{MA} + t_{CB} + t_{Z2reset} + t_S$$

Where:

t_{Z2} = Required Zone-2 time delay

t_{MA} = Operating time of slowest adjacent circuit main protection or Circuit Local back-up for faults within Zone-2 reach

t_{CB} = Associated adjacent circuit breaker clearance time

$t_{Z2reset}$ = Resetting time of Zone-2 impedance element with load current present

t_S = Safety margin for tolerance (e.g. 50 to 100ms)

Unequal lengths of transmission circuit can make it difficult to meet the Zone-2 secondary reach setting criterion. In such cases it will be necessary to co-ordinate Zone-2 with longer time delay. The time t_{MA} in equation must be the adjacent circuit Zone-2 protection operating time.

6. *ZONE-3 TIMER SETTING*

Zone-3 timer should be set so as to provide discrimination with the operating time of relays provided in subsequent sections with which Zone-3 reach of relay being set, overlaps. Typical recommended Zone-3 time is 0.8 to 1.0 second.

For Special cases, where co-ordination between long and short lines is required, following formula would be the basis for determining the minimum acceptable Zone-3 time setting:

$$t_{Z3} > t_{MA} + t_{CB} + t_{Z3reset} + t_S$$

Where:

tZ3 = Required Zone-3 time delay

tMA = Operating time of slowest adjacent circuit local back-up protection

tCB = Associated adjacent circuit breaker clearance time

tZ3reset = Resetting time of Zone-3 impedance element with load current present

tS = Safety margin for tolerance (e.g. 50 to 100milliseconds)

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7. *LOAD IMPEDANCE ENCROACHMENT*

With the extended Zone-3 reach settings, that may be required to address the many under reaching factors already considered, load impedance encroachment is a significant risk to long lines of an interconnected power system. Not only the minimum load impedance under expected modes of system operation be considered in risk assessment, but also the minimum impedance that might be sustained for seconds or minutes during abnormal or emergency system conditions. Failure to do so could jeopardize power system security.

Ideal solution to tackle load encroachment may be based on the use of blinders or by suitably setting the resistive reach of specially shaped impedance elements or by use of polygon type impedance elements.

It is recommended that all the distance relays should have quadrilateral / polygon characteristic. For relays having Mho characteristics, it is desirable to have load encroachment prevention characteristics or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a feeder during emergency system condition, following criteria may be considered for deciding resistive reach / blinder setting to prevent load point encroachment:

- Maximum load current (Imax) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15 minutes rating of the transmission facility).
- Minimum voltage (Vmin) to be considered as 0.85pu (85%).
- For setting angle for load blinder, a value of 30 degree may be adequate in most cases.

For high resistive earth fault where impedance locus lies in the Blinder zone, fault clearance shall be provided by the back-up directional earth fault relay.

8. *ZONE-4 SUBSTATION LOCAL BACKUP PROTECTION SETTINGS*

Zone-3 distance protection is usually targeted to provide only remote back-up protection. In such a case, the distance relay may be provided with an additional zone of reverse-looking protection (e.g. Zone-4) to offer substation-local back-up protection. The criterion for setting Zone-4 reverse reach would be as under.

- The Zone-4 reverse reach must adequately cover expected levels of apparent bus bar fault resistance, when allowing for multiple in feeds from other circuits. For this reason, its resistive reach setting is to be kept identical to Zone-3 resistive reach setting.

With a reverse reach setting of less than the Zone-1 reach of distance protection for the shortest line connected to the local bus bar, the Zone-4 time delay would only need to co-ordinate with bus bar main protection fault clearance and with Zone-1 fault clearance for lines out of the same substation. For this reason this can be set according to the Zone-2 time setting guidelines.

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9. *USE OF SYSTEM STUDIES TO ANALYSE DISTANCE RELAY BEHAVIOUR*

Often during system disturbance conditions, due to tripping of one or more trunk lines, some lines get overloaded and the system voltage drops. During such conditions the back-up distance elements may become susceptible to operation due to encroachment of impedance locus in to the distance relay characteristic.

While the ohmic characteristic of a distance relay is independent of voltage, the load is not generally constant-impedance. The apparent impedance presented to a distance relay, as the load voltage varies, will depend on the voltage characteristic of the load. If the low voltage situation resulted from the loss of one or more transmission lines or generating units, there may be a substantial change in the real and reactive power flow through the line in question. The combination of low voltage and worsened phase angle may cause a long set relay to operate undesirably either on steady state basis, or in response to recoverable swings related to the initiating event.

The apparent impedance seen by the relay is affected by in-feeds, mutual coupling and therefore the behavior of distance relay during various system condition needs to be studied wherever necessary to achieve proper relay coordination.

It is desirable and hence recommended that system studies are conducted using computer-aided tools to assess the security of protection by finding out trajectory of impedance in various zones of distance relay under abnormal or emergency system condition on case-to-case basis particularly for critical lines / corridors.

In addition, the settings must be fine-tuned, simulating faults using Real Time Digital Simulator on case-to-case basis particularly for critical lines / corridors.

Such facilities available at CPRI, POWERGRID or elsewhere in the country should be used for protection related studies.

10. ***DIRECTIONAL PHASE OVER CURRENT PROTECTION***

Directional phase over current relays are still being used as back-up protection for 220kV transmission lines by many utilities. In view of time coordination issues and increased fault clearance time in the event of failure of main distance protection, *it is recommended that for all 220kV lines also main-1 and main-2 protections similar to 400kV lines be provided.*

11. *DIRECTIONAL GROUND OVER CURRENT PROTECTION (DEF) SETTINGS*

Normally this protection is applied as a supplement to main protection when ground fault currents may be lower than the threshold of phase over current protection. It might also be applied as main protection for high resistance faults.

The ground over current threshold should be set to ensure detection of all ground faults, but above any continuous residual current under normal system operation. Continuous residual current may arise because of following:

- Unbalanced series impedances of untransposed transmission circuits
- Unbalanced shunt capacitance of transmission circuits.
- Third harmonic current circulation.

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Various types of directional elements may be employed to control operation of ground over current (zero sequence over current) protection response. The most common approach is to employ Phase angle difference between Zero sequence voltage and current, since the relaying signals can easily be derived by summing phase current signals and by summing phase voltage signals from a suitable voltage transformer.

However, this method is not suitable for some applications where transmission lines terminated at different substations, run partially in parallel. In such cases following type of directional control is recommended to be used for the directional earth fault relay.

- Relative phase of negative sequence voltage and current

To ensure proper coordination, operating time must be set according to following criteria:

The DEF protection should not operate when the circuit local backup protection of remote end clears a fault in an adjacent circuit i.e DEF should be coordinated with the remote end LBB.

12. ***POWER SWING BLOCKING FUNCTION***

While the power-swing protection philosophy is simple, it is often difficult to implement it in a large power system because of the complexity of the system and the different operating conditions that must be studied. There are a number of options one can select in implementing power-swing protection in their system. Designing the power system protection to avoid or preclude cascade tripping is a requirement of modern day power system. Below we list two possible options:

12.1. Block all Zones except Zone-I

This application applies a blocking signal to the higher impedance zones of distance relay and allows Zone 1 to trip if the swing enters its operating characteristic. Breaker application is also a consideration when tripping during a power swing. A subset of this application is to block the Zone 2 and higher impedance zones for a preset time (Unblock time delay) and allow a trip if the detection relays do not reset.

In this application, if the swing enters Zone 1, a trip is issued, assuming that the swing impedance entering the Zone-1 characteristic is indicative of loss of synchronism. However, a major disadvantage associated with this philosophy is that indiscriminate line tripping can take place, even for recoverable power swings and risk of damage to breaker.

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12.2. Block All Zones and Trip with Out of Step (OOS) Function

This application applies a blocking signal to all distance relay zones and order tripping if the power swing is unstable using the OOS function (function built in modern distance relays or as a standalone relay). This application is the recommended approach since a controlled separation of the power system can be achieved at preselected network locations. Tripping after the swing is well past the 180 degree position is the recommended option from CB operation point of view.
Normally all relay are having Power swing Un-block timer which unblocks on very slow power swing condition (when impedance locus stays within a zone for a long duration). Typically the *Power* swing un-blocking time setting is 2sec.
However, on detection of a line fault, the relay has to be de-blocked.

12.3. Placement of OOS trip Systems

Out of step tripping protection (Standalone relay or built-in function of Main relay) shall be provided on all the selected lines. The locations where it is desired to split the system on out of step condition shall be decided based on system studies.
The selection of network locations for placement of OOS systems can best be obtained through transient stability studies covering many possible operating conditions.

Till such studies are carried out and Out-of-Step protection is enabled on all identified lines, it is recommended to continue with the existing practice of Non-Blocking of Zone-I on Power Swing as mentioned under Option-12.1 above. However, it should be remembered that with this practice the line might trip for a recoverable swing and it is not good to breakers.

Committee *strongly recommends that required studies must be carried out at the earliest possible time (within a timeframe of one year) to exercise the option-12.2 & 12.3 above.*

13. *LINE OVERVOLTAGE PROTECTION*

FOR 400kV LINES: Low set stage (Stage-I) may be set in the range of 110% - 112% (typically 110%) with a time delay of 5 seconds. High set stage (Stage-II) may be set in the range 140% - 150% with a time delay of 100milliseconds.

FOR 765kV LINES: Low set stage (Stage-I) may be set in the range of 106% - 109% (typically 108%) with a time delay of 5 seconds. High set stage (Stage-II) may be set in the range 140% - 150% with a time delay of 100milliseconds.

However, for over voltage Stage-I protection, a time grading of 1 to 3 seconds may be provided between overvoltage relays of double circuit lines. Grading on overvoltage tripping for various lines emanating from a station may be considered and same can be achieved using voltage as well as time grading. Longest timed delay should be checked with expected operating time of Over-fluxing relay of the transformer to ensure disconnection of line before tripping of transformer.

It is desirable to have Drop-off to pick-up ratio of overvoltage relay better than 97% (Considering limitation of various manufacturers relay on this aspect).

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14. *LINE DIFFERENTIAL PROTECTION*

Many transmission lines are now having OPGW or separate optic fiber laid for the communication. Where ever such facilities are available, it is recommended to have the line differential protection as Main-I protection with distance protection as backup (built-in Main relay or standalone). Main-II protection shall continue to be distance protection. For cables and composite lines, line differential protection with built in distance back up shall be applied as Main-I protection and distance relay as Main-II protection. Auto-recloser shall be blocked for faults in the cables.

15. *MAINTAINING OPERATION OF POWER STATION AUXILIARY SYSTEM OF NUCLEAR POWER PLANTS:*

Depression of power supply voltages for auxiliary plant in some generating stations may reduce the station output. Maintenance of full generation output may be a critical power system security factor. In the case of nuclear plant, auxiliary power supplies are also a major factor in providing full nuclear plant safety and security.

The potential loss of system generation or the potential challenges to nuclear plant safety systems may be factors which will dictate the longest acceptable clearance times for transmission circuit faults in the vicinity of a power station. This should be further taken up with utilities of nuclear plants and this and any other requirements should be understood and addressed.

16. ***COORDINATION BETWEEN SYSTEM STUDY GROUP AND PROTECTION ENGINEERS***

For quite a few cases where system behavior issues are involved it is recommended that power system study group is associated with the protection engineers. For example power swing locus, out of step tripping locations, faults withstands capability, zone2 and zone3 overlap reach settings calculations are areas where system study group role is critical/essential.

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RECOMMENDED METHODOLOGY FOR RELAY SETTINGS OF SERIES COMPENSATED TRANSMISSION LINES:

Following phenomenon associated with the protection of Series compensated lines require special attention:

1) *VOLTAGE AND CURRENT INVERSION*

1.1. Voltage inversion on Series Compensated line:

In this case the voltage at the relay point reverses its direction. This phenomenon is commonly called as voltage inversion. Voltage inversion causes false decision in conventional directional relays. Special measures must be taken in the distance relays to guard against this phenomenon.

1.2. Current inversion on Series Compensated line:

Fault current will lead source voltage by 90 degrees if $X_C > X_S + X_{L1}$ Current inversion causes a false directional decision of distance relays (voltage memories do not help in this case). [Here X_C is reactance of series capacitor, X_S is source reactance and X_{L1} is reactance of the line]

Current inversion influences operation of distance relays and therefore they cannot be applied without additional logic for the protection of series compensated lines when possibility of current inversion exists. Performance of directional comparison protections, based on residual (zero sequence) and negative sequence currents are also affected by current inversion. *It is therefore, recommended to check the possibility of current inversion through system studies at the planning stage itself.*

2) *LOW FREQUENCY TRANSIENTS*

Series capacitors introduce oscillations in currents and voltages in the power systems, which are not common in non-compensated systems. These oscillations have frequencies lower than the rated system frequency and may cause delayed increase of fault currents, delayed operation of spark gaps as well as delayed operation of protective relays.

Low frequency transients have in general no significant influence on operation of line current differential protection as well as on phase comparison protection. However they may significantly influence the correct operation of distance protection in two ways:

-They increase the operating time of distance protection, which may in turn influence negatively the system stability

-They may cause overreaching of instantaneous distance protection zones and this way result in unnecessary tripping on series compensated lines.

It is recommended to reduce the reach setting by a safety factor (Ks) to take care of possible overreach due to low frequency oscillations.

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3) *MOV INFLUENCE AND APPARENT IMPEDANCE*

Metal oxide varistors (MOV) are used for capacitor over-voltage protection. In contrast to spark gaps, MOVs carry current when the instantaneous voltage drop across the capacitor becomes higher than the protective voltage level in each half-cycle. Extensive studies have been done by Bonneville Power Administration in USA to arrive at a non-linear equivalent circuit for a series connected capacitor using an MOV. The composite impedance depends on total fault current and protection factor k_p.

The later is defined by equation.

$$k_p = \frac{U_{MOV}}{U_{NC}}$$

Where U_{MOV} is voltage at which MOV starts to conduct theoretically and U_{NC} is voltage across the series capacitor when carrying its rated nominal current

This should be considered while relay setting.

4) *IMPACT OF SC ON PROTECTIVE RELAYS OF ADJACENT LINES*

Voltage inversion is not limited only to the buses and to the relay points close to the series compensated line. It can spread deep into the network and this way influence the selection of protection devices (mostly distance relays) at remote ends of the lines adjacent to the series compensated circuit, and sometimes even deeper in the network. Estimation of their influence on performances of existing distance relays of adjacent lines must be studied. In the study, it is necessary to consider cases with higher fault resistances, for which spark gaps or MOVs on series capacitors will not conduct at all.

If voltage inversion is found to occur, it may be necessary to replace the existing distance relays in those lines with distance relays that are designed to guard against this phenomenon.

5) *MULTI CIRCUIT LINES*

Two parallel power lines both series compensated running close to each other and ending at the same busbar at both ends can cause some additional challenges for distance protection due to the zero sequence mutual impedance. The current reversal phenomenon can also raise problems from the protection point of view, particularly when the power lines are relatively short and when permissive overreach schemes are used.

Influence of zero sequence mutual impedance

Zero sequence mutual impedance Z_{M0} will not significantly influence the operation of distance protection as long as both circuits are operating in parallel and all precautions related to settings of distance protection on series compensated line have been considered. Influence of parallel line switched off & earthed at both ends, on the operation of distance protection on single operating circuit is well known.

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The presence of series capacitor additionally exaggerates the effect of zero sequence mutual impedance between two circuits. The effect of zero sequence mutual impedance on possible overreaching of distance relays is increased further compared to case of non-compensated lines. This is because while the series capacitor will compensate self-impedance of the zero sequence network the mutual impedance will be same as in the case of non-compensated double circuit lines. The reach of under reaching distance protection zone 1 for phase to earth measuring loops must further be reduced for such operating conditions.

Zero sequence mutual impedance may also disturb the correct operation of distance protection for external evolving faults during auto reclosing, when one circuit is disconnected in one phase and runs in parallel during dead time of single pole auto reclosing cycle. *It is recommended to study all such operating conditions by dynamic simulations in order to fine tune settings of distance relays.*

6) <u>DIRECTIONAL RESIDUAL OVERCURRENT PROTECTION</u>

All basic application considerations, characteristic for directional residual over-current protection on normal power lines apply also to series compensated lines with following additions. Low fault currents are characteristic of high resistive faults. This means that the fault currents may not be enough to cause voltage drops on series capacitors that would be sufficient to start their over-voltage protection. Spark gaps may not flash over in most cases, and metal oxide varistors (MOVs) may not conduct any significant current. Series capacitors may remain fully inserted during high resistive earth faults.

Local end directional residual OC protection:

The directional relay operates always correctly for reverse faults. VT located between bus and capacitor generally does not influence directional measurement. But in case VT is located between line and capacitor it may influence correct operation: While reverse faults are detected correctly the forward operation is dependent on system conditions. Additional zero sequence source impedance can be added into relay circuits to secure correct directional measurement.

Remote end directional residual OC protection:

In this case the current can be reduced to extremely low values due to low zero sequence impedance at capacitor end. Further the measured residual voltage can be reduced to very low value due to low zero sequence source impedance and/or low zero sequence current. Zero sequence current inversion may occur at the capacitor end (dependent on fault position). Directional negative sequence OC protection too may face very similar conditions.

Adaptive application of both the above OC protection principles can be considered wherever required to get the desired result.

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7) *DISTANCE PROTECTION SETTINGS GUIDELINES*

- Basic criteria applied for Z1 & Z2 reach settings are :
  - Zone-1 should never overreach for the fault at remote bus
  - Zone-2 should never under reach for fault on protected line
  - Permissive overreach (POR) schemes are usually applied

Distance protection Zone 1 shall be set to

Zone-1 is set usually at 80% of Ks x $X_{Z1} = K_S \cdot (X_{11} + X_{12} - X_C)$ Where X_{11} is reactance between CT and capacitor and X_{12} is reactance between capacitor and remote end Bus, X_c is reactance of capacitor and K_S is safety factor to prevent possible overreaching due to low frequency (sub-harmonic) oscillations. These setting guidelines are applicable when VT is installed on the bus side of the capacitor . It is possible to remove X_C from the above equation in case VT is installed on line side , but it is still necessary to consider the safety factor.

- Alternatively, Zone-1 is set at 80% of line impedance with a time delay of 100millisecond. POR Communication scheme logic is modified such that relay trips instantaneously in Zone-1 on carrier receive. (For remote end relay of the line looking into series capacitor)
- Zone-2 is set to 120 % of uncompensated line impedance for single circuit line. For double circuit lines, special considerations are mentioned at Section B-5 above.
- Phase locked voltage memory is used to cope with the voltage inversion. Alternatively, an intentional time delay may be applied to overcome directionality problems related to voltage inversion.
- Special consideration may be required in over voltage stage-I (low set) trip setting for series compensated double circuit lines. It has been experienced that in case of tripping of a heavily loaded circuit, other circuit experience sudden voltage rise due to load transfer. To prevent tripping of other circuit on such cases, over-voltage stage-I setting for series compensated double circuit lines may be kept higher at 113%.

8) *SIMULATION STUDIES*

System studies, Use of real Time digital simulators, Tests using EMTP files are very important when applying protections for series compensated lines. It is recommended to carry out such studies specific to each line.

*****

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General Information:

1. Name of Sub-station
2. Date of first commissioning
3. Type of Bus Switching Scheme:
4. Whether SLD collected or Not:

Audit Team:

1. ………………
2. ………………
3. ………………

(1) Instrument Transformer (To be filled for each one of them)

A. Current transformer (C T)

a. Location of CT
b. Date of CT ratio Test Testing
c. Test Results

		Core I	Core II	Core III	Core IV	Core V	Core VI
I	Ratio Adopted						
ii	Ratio measured						
iii	error calculated						
	Knee point voltage						

B. Capacitive voltage transformer (C V T)

1	**Location of CVT**			
a	Date of Testing			
b	CVT ratio Test			
		Core I	Core II	Core III
i	Ratio Adopted			
ii	Ratio measured			
iii	error calculated			
2	**Location of CVT**			
a	Date of Testing			
b	CVT ratio Test			
		Core I	Core II	Core III
i	Ratio Adopted			
ii	Ratio measured			
iii	error calculated			

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(2) Availability of Protection System

A. Bus Bar relay

		765kV	400kV	220kV
i)	Make and Model of Bus Bar relay			
ii)	Whether stability checks done or not			
iii)	Date of testing			
iv)	Remarks (if any)			

B. Sub-station protection and monitoring Equipments

	System	LBB (Make & Model)	Functional (Yes / No)	Date of last testing	Event Logger (Make & Model)	Functional (Yes / No)	Synchonis-ing Facility Available or not	Synchro Check Relay (Make & Model)	Setting of Synhro check Relay
i)	765kV System								
II)	400kV System								
III)	220kV System								

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C. Transmission Line Protection

1	Line-1 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
2	Line-2 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
3	Line-3 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
4	Line-4 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
5										

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D. Transformer Protection

1	ICT-1 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
2	ICT-3 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
3	ICT-3 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
		Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
4						

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E. Reactor Protection

1	Reactor-1 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing	
2	Reactor-2 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing	
3	Reactor-3 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing	

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(3) Line Parameter

		Line-1	Line-2	Line-3	Line-4	Line-5
Name of Line						
Line length (km)						
Line Parameters (In Ohms/Per KM/Per Phase Primary value)	R1					
	X1					
	R_0					
	X_0					
	R_0M					
	X_0M					
Relay setting	Adopted	Please enclose the settings for all lines, transformers, Reactors and Bus Bars as Annexure-I				
	Recommended	Please enclose the settings for all lines, transformers, Reactors and Bus Bars as Annexure-II				

(4) DC Supply

		220 /110 V DC-I	220 /110 V DC-II	48 V DC-I	48 V DC-II
a)	Measured voltage (to be measured at farthest Panel				
i.	Positive to Earth			NA	NA
ii.	Negative to Earth				
b)	No. of Cells Per Bank				
c)	Availability of Battery Charger	Yes/No	Yes/No	Yes/No	Yes/No

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(5) Circuit Breakers

		Make and Model	Status of Breaker Available or Not	No.of trip/close coil & healthiness	PIR (Available or Not)	Date of Last Timing taken	Remarks (If any)
A	765kV System						
i	765kV bay-1						
ii	765kV bay-2						
iii	765kV bay-3						
iv	765kV bay-4						
v	765kV bay-5						
B	400kV System						
i	400kV bay-1						
ii	400kV bay-2						
iii	400kV bay-3						
iv	400kV bay-4						
v	400kV bay-5						
vi	400kV bay-6						
C	220kV System						
i	220kV bay-1						
ii	220kV bay-2						
iii	220kV bay-3						
iv	220kV bay-4						
v	220kV bay-5						

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(6) Availability of Auxiliary Supply

Auxiliary Supply-1: Source of supply: ....
Reliability of Supply: ....
Average trippings per month: ....

Auxiliary Supply-2: Source of supply: ....
Reliability of Supply: ....
Average trippings per month: ....

....
....

DG Set-1: Make ....
Rating ....
Weather on Auto or Manual ....
Fuel Level ....

DG Set-1: Make ....
Rating ....
Weather on Auto or Manual ....
Fuel Level ....

....
....

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(7) Availability of UFR Relay

Make …………………

Setting ………………..

(8) Availability of DF/DT Relay

Make …………………

Setting ………………..

(9) Special System Protection Scheme (SPS)

Available (Yes/No) …………………

Verification ………………..

(10) Status of corrective actions based on Tripping Analysis

…………………………………………………

……………………………………………….

(11) Any other observation/ comments

…………………………………………………

………………………………………………..

Appendix-9.4

CHECK LIST TO ENABLE AUDIT OF PRACTICES FOLLOWED IN PROTECTION APPLICATION & CRITERIA USED FOR SETTING CALCULATIONS IN 220KV, 400KV & 765KV SUBSTATIONS

CHECK-LIST: Check list for different protected objects & elements in fault clearance system are as under:

(put √ mark in the appropriate box)

A. Transmission Lines (OHL and Cables)

1.	Independent Main-I and Main-II protection (of different make OR different type) is provided with carrier aided scheme	☐ YES ☐ NO
2.	Are the Main-I & Main-II relays connected to two separate DC sources (Group-A and Group-B)	☐ YES ☐ NO
3.	Is the Distance protection (Non-switched type, suitable for 1-ph & 3-ph tripping) as Main1 and Main2 provided to ensure selectivity & reliability for all faults in the shortest possible time	☐ YES ☐ NO
4.	Is both main-I & Main-II distance relay are numerical design having Quadrilateral or Polygon operating characteristic	☐ YES ☐ NO
5.	In the Main-I / Main-II Distance protection, Zone-I is set cover 80% of the protected line section	☐ YES ☐ NO
6.	In the Main-I / Main-II distance protection, Zone-2 is set cover 120% of the protected line section in case of Single circuit line and 150% in case of Double circuit line	☐ YES ☐ NO
7.	In the Main-I / Main-II distance protection, Zone-3 is set cover 120% of the total of protected line section plus longest line at remote end as a minimum.	☐ YES ☐ NO
8.	Resistive reach for Ground fault element set to give maximum coverage considering fault resistance, arc resistance & tower footing resistance. (In case, It is not possible to set the ground fault and phase fault reaches separately, load point encroachment condition imposed on Phase fault resistive reach shall be applied)	☐ YES ☐ NO
9.	Resistive reach for Phase fault element set to give maximum coverage subject to check of possibility against load point encroachment considering minimum expected voltage and maximum load.	☐ YES ☐ NO
10.	In case of short lines, is manufacturers recommendation considered in respect of resistive setting vis a vis reactance setting to avoid overreach.	☐ YES ☐ NO
11	Is Zone-2 time delay of Main-I / Main-II distance relay set to 0.350 seconds ? In case any other value has been set for Zone-II timer, kindly specify the value and justification thereof.	☐ YES ☐ NO
12	Is Zone-3 timer is set to provide discrimination with the operating time of relays at adjacent sections with which Zone-3 reach of relay is set to overlap. Please specify the Zone-3 time set.	☐ YES ☐ NO
13.	Is Zone-4 reach set in reverse direction to cover expected levels of apparent bus bar fault resistance, when allowing for multiple in feeds from other circuits?	☐ YES ☐ NO
14.	Is reverse looking Zone-4 time delay set as Zone-2 time delay?	☐ YES ☐ NO

15.	Is Switch on to fault (SOTF) function provided in distance relay to take care of line energisation on fault? Whether SOTF initiation has been implemented using hardwire logic In case of Breaker and half switching scheme, whether initiation of line SOTF from CB closing has been interlocked with the other CB	☐ YES ☐ NO ☐ YES ☐ NO ☐ YES ☐ NO
16.	Whether VT fuse fail detection function has been correctly set to block the distance function operation on VT fuse failure	☐ YES ☐ NO
17.	Is the sensitive IDMT directional E/F relay (either separate relay or built-in function of Main relay) for protection against high resistive earth faults?	☐ YES ☐ NO
18.	Is additional element (Back-up distance) for remote back-up protection function provided in case of unit protection is used as Main relay for lines?	☐ YES ☐ NO
19.	In case of Cables, is unit protection provided as Main-I & Main-II protection with distance as back-up.	☐ YES ☐ NO
20.	Are the line parameters used for setting the relay verified by field testing	☐ YES ☐ NO
21.	Is Two stages Over-Voltage protection provided for 765 & 400kV Lines? Do you apply grading in over-voltage setting for lines at one station. Please specify the setting values adopted for: Stage-I : (typical value - 106 to 112 % , delay : 4-7 Sec) Stage-II: (typical value - 140 to 150%, delay: 0 to 100msec.)	☐ YES ☐ NO ☐ YES ☐ NO ……………..
22.	Is 1-ph Auto –reclosing provided on 765, 400 & 220kV lines? Please specify the set value: Dead time: (typical 1 Sec) Reclaim time: (typical 25 Sec)	☐ YES ☐ NO …… ……
23.	Is the Distance communication. Scheme Permissive Over Reach (POR) applied for short lines and Permissive Under Reach (PUR) applied for long lines? If any other communication scheme has been applied, please provide the detail with justification thereof.	☐ YES ☐ NO ……………
24.	Is the Current reversal guard logic for POR scheme provided on Double circuit lines?	☐ YES ☐ NO
25.	In case the protected line is getting terminated at a station having very low fault level i.e. HVDC terminal, whether week end-infeed feature has been enabled in respective distance relay or not	☐ YES ☐ NO
26.	In case of protected line is originating from nuclear power station, are the special requirement (stability of nuclear plant auxiliaries) as required by them has been met	☐ YES ☐ NO
27.	What line current , Voltage and Load angle have been considered for Load encroachment blinder setting and what is the resultant MVA that the line can carry without load encroachment. (In the absence of Load encroachment blinder function, this limit shall be applied to Zone-3 phase fault resistive reach.)	I= V= Angle: S=
28.	a) What are the Zones blocked on Power swing block function: b) Setting for Unblock timer: (typical 02 second) c) Out of Step trip enabled	Z1 / Z2 / Z3 / Z4 Time: ☐ YES ☐ NO
29.	Whether the location of Out of step relay has been identified on the basis of power system simulation studies	☐ YES ☐ NO

30.	a) Is Disturbance recorder and Fault locator provided on all line feeder ? b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC d) Whether DR is time synchronised with the GPS based time synchronising equipment e) Whether DR analog channels contain line phase & neutral current and line phase & neutral voltage. f) Whether DR digital channel as a minimum contain the CB status, Main-I & II trip status, LBB trip status, Over-voltage trip status, Stub protn trip status, Permissive and direct carrier receive status, Line reactor trip status.	☐ YES ☐ NO Standalone / built-in ☐ YES ☐ NO ☐ YES ☐ NO ☐ YES ☐ NO ☐ YES ☐ NO
31.	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	☐ YES ☐ NO

B. Power Transformers

1.	Do you use Group A and Group B protections connected to separate DC sources for power transformers	☐ YES ☐ NO
2.	Do you follow CBIP guideline (274 & 296) for protection setting of transformer	☐ YES ☐ NO
3.	Do you use duplicated PRD and Bucholtz initiating contact for power transformers at 765kV and 400kV levels	☐ YES ☐ NO
4.	Do you classify transformer protections as below in groups: Group A — Group B • Biased differential relay — Restricted earth fault (REF) relay • PRD , WTI — Buchholz Protection, OTI • Back up Protection(HV) — Back up Protection(MV) • Over fluxing protection(HV) — Over fluxing protection(MV)	☐ YES ☐ NO Group A or B
5.	In case of Breaker & half switching scheme, whether CT associated with Main & Tie Breakers are connected to separate bias winding of the low impedance Biased differential protection in order to avoid false operation due to dissimilar CT response.	☐ YES ☐ NO
6.	Is Restricted earth fault (REF) protection used a high impedance type	☐ YES ☐ NO
7.	Are Main protection relays provided for transformers are of numerical design.	☐ YES ☐ NO
8.	a) Are directional over current & earth fault relays provided as back-up protection of Transformer are of numerical design. b) Do the back-up earth fault relays have harmonic restrain feature	☐ YES ☐ NO ☐ YES ☐ NO
9.	Is Fire protection system (HVW type) provided for power transformer and functioning	☐ YES ☐ NO
10.	a) Is the Disturbance recorder provided for Transformer feeder b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC d) Whether DR is time synchronised with the GPS time synchronising equipment	☐ YES ☐ NO Standalone/built-in ☐ YES ☐ NO ☐ YES ☐ NO

11.	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	☐ YES ☐ NO

C. Shunt Reactors

1.	Do you use Group A and Group B protections connected to separate DC sources for reactors	☐ YES ☐ NO
2.	Do you follow CBIP guideline (274 and 296) for protection setting of reactors	☐ YES ☐ NO
3.	Do you use duplicated PRD and Bucholtz initiating contact for Reactors at 765kV and 400kV levels	☐ YES ☐ NO
4.	Do you classify Reactor protections as below in groups: Group A: • Biased differential relay • PRD , WTI • Back up impedance protection Group B: R.E.F Protection; Buchholz Protection, OTI; Direction O/C & E/F relay	☐ YES ☐ NO Group A or B
5	In case of Breaker & half switching scheme, whether CT associated with Main & Tie Breakers are connected to separate bias winding of the low impedance Biased differential protection in order to avoid false operation due to dissimilar CT response.	☐ YES ☐ NO
6	Is Restricted earth fault (REF) protection used a high impedance type	☐ YES ☐ NO
7	Are Main & back-up protection relays provided for Reactor are of numerical design.	☐ YES ☐ NO
8	Is Fire protection system (HVW type) provided for Reactor and functioning	☐ YES ☐ NO
9	a) Is the Disturbance recorder and Fault locator provided on all the Shunt Reactors used in 765 kV, 400 kV substations? b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC	☐ YES ☐ NO Standalone/built-in ☐ YES ☐ NO
10.	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	☐ YES ☐ NO

D. Bus bars

1.	Bus Bar protection for 765, 400 & 220kV buses is provided	☐ YES ☐ NO
2.	Duplicated Bus bar protection is provided for 765kV and 400kV buses	☐ YES ☐ NO
3.	CBIP guideline for Protection (274 and 296) settings is followed	☐ YES ☐ NO
4	In an existing substation if CTs are of different ratios, is biased type bus protection provided.	☐ YES ☐ NO
5	In stations where single bus bar protection is provided, is backup provided by reverse looking elements of distance relays or by second zone elements of remote end distance relays?	☐ YES ☐ NO

6	In case of GIS where burn through time of SF6 is shorter than remote back up protection is the bus bar protection duplicated irrespective of voltage level?	☐ YES ☐ NO
7	Since it is difficult to get shutdowns to allow periodic testing of bus protection, numerical bus protections with self-supervision feature is an answer. Is this followed?	☐ YES ☐ NO
8	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	☐ YES ☐ NO

E. Disturbance Recorder (DR) and Event Logger (EL)

1	a) Is the Disturbance recorder and Fault locator provided on all line feeders of 765, 400 & 220kV substations? b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC d) Whether Central PC for DR , EL are powered by Inverter (fed from station DC)	☐ YES ☐ NO Standalone / built-in ☐ YES ☐ NO ☐ YES ☐ NO
2.	Whether DR is having the following main signals for lines: Analogue signals: • From CT: IA, IB, IC, IN • From VT: VAN, VBN, VCN • From Aux. VT: V0 Digital Signals • Main 1 Carrier receive • Main 1 Trip • Line O/V Stage I / Stage II • Reactor Fault Trip • Stub Protection Operated. • Main II Trip • Main II Carrier Receive • Direct Trip CH I / II • CB I Status (PH-R, Y & B) • CB II Status (PH R, Y & B) • Bus bar trip • Main / Tie CB LBB Operated • Main / Tie Auto-reclose operated. DR for Transformer / Reactor feeder should contain analog channel like input currents & voltage. Binary signal include all protection trip input, Main & Tie CB status, LBB trip	☐ YES ☐ NO
3.	Whether substation (765, 400 , 220kV) is having Event logger facility (standalone or built-in-SAS)	☐ YES ☐ NO
4.	Whether GPS based time synchronizing equipment is provided at the substation for time synchronizing of Main relays / DR/ Event logger / SAS/ PMU / Line Current Differential Relays	☐ YES ☐ NO

F. Circuit Breakers

1.	Is breaker fail protection (LBB / BFR) provided for all the Circuit Breakers at 220kV , 400kV & 765kV rating	☐ YES ☐ NO
3.	For Circuit Breaker connected to line feeder / transformer feeder, whether operation of LBB / BFR sends direct trip signal to trip remote end breaker ?	☐ YES ☐ NO

4.	For lines employing single phase auto reclosing, Is start signal from protection trip to LBB / BFR relay is given on single phase basis?	☐ YES	☐ NO
5.	Is separate relay provided for each breaker and the relay has to be connected from the secondary circuit of the CTs associated with that particular breaker?	☐ YES	☐ NO
6.	Is LBB relay provided with separate DC circuit independent from Group-A and Group-B Protections?	☐ YES	☐ NO
7.	Is the LBB initiation provided with initiating contact independent of CB trip relay contact?	☐ YES	☐ NO
8.	Is Separation maintained between protective relay and CB trip coil DC circuit so that short circuit or blown fuse in the CB circuit will not prevent the protective relay from energizing the LBB scheme?	☐ YES	☐ NO
9.	Is LBB relay initiated by Bus bar protection in addition to other fault sensing relays, since failure of CB to clear a bus fault would result in the loss of entire station if BFP relay is not initiated?	☐ YES	☐ NO
10.	Is tripping logic of the bus bar protection scheme used for LBB protection also?	☐ YES	☐ NO
11.	Are the special considerations provided to ensure proper scheme operation by using Circuit Breaker contact logic in addition to current detectors in cases breaker-fail relaying for low energy faults like buckholz operation?	☐ YES	☐ NO
12.	Are the Current level detectors set as sensitive as the main protection? (Generally setting of 0.2 A is commonly practiced for lines and transformers)	☐ YES	☐ NO
13.	Is timer set considering breaker interrupting time, current detector reset time and a margin? (Generally a timer setting of 200ms has been found to be adequate)	☐ YES	☐ NO
14.	Is the back-up fault clearance time is shorter than the operating time of the remote protections (distance relay Zone-2) ?	☐ YES	☐ NO
15.	Is the breaker failure protection provided with two steps (First stage – retrip own CB, Second stage- Trip all associated CBs) . This mitigates unwanted operation of breaker failure protection during maintenance and fault tracing.	☐ YES	☐ NO
16.	Is the breaker failure protection hardware provided is separate from line /transformer feeder protection?	☐ YES	☐ NO

G. Communication systems

1.	a) Do you use PLCC for tele-protection of distance relays at 765, 400 & 220kV feeders	☐ YES ☐ NO
	b) Specify type of coupling	(Ph-Ph / Ph-G/ Inter-ckt)
	c) Whether redundant PLCC channels provided for 400 & 765kV lines	☐ YES ☐ NO
	d) Specify number of PLCC channels per circuit :	(One / two)
	e) Whether dependability & security of each tele-protection channel measured & record kept ?	☐ YES ☐ NO

2.	a) In case you use OPGW for tele-protection, are they on geographically diversified route for Main-I and Main-II relay? b) Whether dedicated fibre is being used for Main-I / Main-II relay or multiplexed channel are being used.	☐ YES ☐ NO Dedicated / multiplexed

H. Station DC supply systems

1.	Do you have two separate independent DC system (220V or 110V) (Source-A and Source-B)	☐ YES ☐ NO
2.	Do you have two independent DC system (48V) for PLCC (source-A and source-B)	☐ YES ☐ NO
3.	There is no mixing of supplies from DC source-A and DC source-B	☐ YES ☐ NO
4.	Whether the protection relays and trip circuits are segregated into two independent system fed through fuses from two different DC source	☐ YES ☐ NO
5.	Whether Bay wise distribution of DC supply done in the following way: a) Protection b) CB functions c) Isolator / earth switch functions d) Annunciation / Indications e) Monitoring functions	☐ YES ☐ NO
6	Whether following has been ensured in the cabling: a) Separate cables are used for AC & DC circuits b) Separate cables are used for DC-I & DC-II circuits c) Separate cables are used for different cores of CT and CVT outputs to enhance reliability & security	☐ YES ☐ NO
7	Is guidelines prescribed in CBIP manual 274 & 296 followed in general	☐ YES ☐ NO

I. PERFORMANCE INDICES

1.	Is there a system of periodically measuring Dependability & Security of Protection system (as given in CBIP manual 296) and recorded	☐ YES ☐ NO
2.	Is there a system of periodically measuring Dependability of switchgear associated with Protection system and recorded	☐ YES ☐ NO
3.	Is there a process of Root cause analysis of unwanted tripping events	☐ YES ☐ NO
4.	Are improvement action like revision of relay setting, better maintenance practices, modernising & retrofitting of switching & protection system taken based on above data.	☐ YES ☐ NO
5.	Is attention also given to DC supply system, tele-protection signalling, healthiness of tripping cables, terminations etc. in order to improve the performance of fault clearance system	☐ YES ☐ NO

J. ADDITIONAL CHECKS FOR SERIES COMPENSATED LINES

1.	What is the operating principle of Main protection employed	☐ Distance ☐ Line Current diff.

2.	Are both main-I & Main-II distance relay are numerical design	☐ YES ☐ NO
3.	Are both main-I & Main-II distance relay suitable for Series compensated lines	☐ YES ☐ NO
4.	Are POR tele-protection scheme employed for distance relays	☐ YES ☐ NO
5.	Position of Line VT provided on series compensated line	☐ Between Capacitor and line ☐ Between Capacitor and Bus
6.	What is the under reaching (Zone 1) setting used in teleprotection schemes (Local & Remote end)	% of line length Rationale:
7.	What is the overreaching (Zone 2) setting in used teleprotection schemes	% of line length Rationale:
8.	What kinds of measurement techniques are used to cope with voltage inversion?	☐ Phase locked voltage memory ☐ Intentional time delay Other, specify:
9.	Whether system studies carried out to check the possibility of current inversion due to series compensation	☐ YES ☐ NO
10.	Whether any system studies conducted to find the impact of series compensation on the performance of protections installed on adjacent lines? If yes, how many lines were found to be affected. Pl. specify ________________	☐ YES ☐ NO
11	If YES, are the affected protections on adjacent lines changed / setting revised after the introduction of series compensation?	☐ YES ☐ NO
12.	Is dynamic simulation done to fine tune settings of distance relay installed on series compensated double circuit lines?	☐ YES ☐ NO
13.	Whether performance of directional earth fault relay verifies by simulation studies	☐ YES ☐ NO
14.	When is flashover of spark gaps expected?	☐ For protected line Faults up to ohms ☐ For external faults an adjacent lines
15.	Whether measures taken for under/overreach problems at sub-harmonic oscillations?	☐ YES ☐ NO
16.	Whether MOV influence considered while setting the distance relay reach	☐ YES ☐ NO
17.	Have you experienced any security problems (Relay mal-operation) with high frequency transients caused by ☐ Flashover of spark gaps ☐ Line energisation Other, specify:	☐ YES ☐ NO
18.	If YES, how the above problem has been addressed?	

CHAPTER –X

10. CONCLUSIONS AND RECOMMENDATIONS

As discussed in earlier chapters, the Task Force has arrived at specific recommendations on plan of action for operation of the grid in a secure manner. A summary of the findings and recommendations is given in this chapter.

10.1 SYSTEM STUDIES

10.1.1 Exercises such as analysis of grid conditions and factors affecting operation of grid as and simulation of system conditions corresponding to critical operation conditions expected in forthcoming seasons should be done on a regular basis and suitable operation strategy worked out. Exercise for present grid conditions and forthcoming season e.g. peak load conditions of July-September 2013 have been done and the same are reported in Chapter-3 and Chapter-4 of this report, Similar exercises should be done on a regular basis and load dispatchers appraised of findings of operational planning studies so that suitable operation strategy is worked and implemented.

10.1.2 Load dispatchers at National and Regional level should be equipped to carry out load flow, contingency and stability studies of real-time network taking data from SCADA system for assessing safe transmission capacity on a real-time basis for having a vivid picture of security impact of various contingency depletions under real time operating conditions and taking necessary actions towards ensuring grid security in best possible manner.

10.2 ISLANDING SCHEMES

10.2.1 The report on Grid Disturbances has specific recommendations on implementation of certain islanding schemes. Islanding scheme for Delhi system having four islands has been proposed. Many of the utilities are also planning to have islanding schemes covering some of the generation plants along with loads that can be isolated along with generation plants. If all these proposals are accepted, the system would have a very large number of islanding schemes which may not be in interest of secure integrated operation of grid.

10.2.2 It also observed that in the proposed islanding scheme for Delhi, opening of a large number of elements has been envisaged. For the island formation, all the elements connecting to rest of grid have to be opened simultaneously. Failure in simultaneous opening of interconnecting feeders can happen due to communication failure or mal operation. This may jeopardize successful formation of Delhi Island. Also, the rest of grid would lose all interconnecting lines along with islanding sub part and it would cause major depletion in an already distressed grid. If trigger occurs in a mal-operation, the islanding scheme itself would become a cause of grid disturbance.

10.2.3 The Task Force felt that instead of planning large number of islanding scheme in an adhoc manner, it would be better to evolve some guidelines based on which proposals for islanding schemes could be formulated. There is also a need to review the settings of under frequency relays and also the quantum of load shedding to be done under various system operating conditions. Based on detailed discussions held in the task force meetings, guidelines as given in Chapter-5, para 5.7, are proposed for the purpose of proposing, evaluating, reviewing, finalizing and implementing islanding schemes.

10.3 **TRANSMISSION OPERATIONAL PLANNING CRITERIA :** The Task Force has felt that there is a need of having a Transmission Operational Planning Criteria different from Transmission Planning Criteria of CEA which forms basis for network expansion planning. While ‘N-1’ or ‘N-1-1’ may suffice for expansion planning, operational security may require ‘N-x-1’, “N-x-1-1’ or ‘N-x-2’ or even higher particularly in view of outage of multiple elements. However, it needs to be kept in view that restricting dispatches based on security criteria much higher than that adopted for planning would result in drastically curtailing power supplies in an already deficit scenario. As such, violation of higher security criteria has to be used as a trigger for alert, alarmed or emergency status. The issues require further deliberations to evolve optimal operational strategy.

10.4 FREQUENCY REGULATION

10.4.1 It is seen that improvement in frequency is in term of overall increase in average level and not that much in narrowing down the frequency band. With increase in average frequency, increase in percentage of time frequency is above 50.2 HZ is also being observed. This is not a good indication. There is scope for improvement and establishment of the tighter frequency band of operation together with reduction in load curtailment with increased utilization of generation while maintaining better grid security. This requires better management of the schedules by the various utilities by proper load management and ensuring stable frequency through Free Governor Mode of Operation of the generators together with secondary and tertiary control mechanism.

10.4.2 Operation of the grid with a stable frequency would enhance system security. This would require implementation of frequency control through governor action of generators. The Task Force has observed that it is essential to have system operation based on day ahead and real time load forecast together with mechanism for secondary and tertiary control through maintaining of spinning reserves. Mechanism for settlement of deviations would also require a change from frequency linked UI tariff regime to a system of settlement in kind and penalty for exceeding deviations from specified limits. The existing UI mechanism needs to be reviewed and conflicts removed so that it does not come in the way of governor mode of operation. Issues need to be addressed expeditiously.

10.5 **INTEGRATION OF RENEWABLE ENERGY IN THE GRID :** Integration of renewable energy in the grid is one of the biggest thrust areas. The installed generation capacity of renewable generators is expected to grow manifold in the coming years. Considering the variability and infirmity of generation from renewable resources, there is a need to have strong interconnections together with stable grid frequency maintained close to the nominal operating frequency in a narrower band so that energy injection from renewable sources can be safely absorbed in the grid.

10.6 **CONTROLLING HIGH VOLTAGES IN GRID DURING PERIODS OF LOW LINE LOADINGS**:

10.6.1 One of the problems affecting the operation of the grid is high voltages in the grid during period of low line loadings. Under such conditions, even after exhausting management of all reactive power elements there is a need to open number of 400 kV lines to control the high voltages which results in reduced system reliability.

10.6.2 The Central Transmission Utility (CTU) has planned installation of number of shunt reactors in the grid to control the over voltages. However, it is observed that even the generator buses face high voltages. Therefore, there is need to review the tap setting on all generator transformers and take advantage of the reactive capability of the generators and regulation of the excitation system so that the voltage profile of the grid is properly managed.

10.6.3 **Reactive power management towards controlling voltage profile** is an important area of attention. Generator reactive capability is required to maintain proper system voltage levels, provide appropriate dynamic reserves and assure service reliability. However, it was generally observed that generators shy away from providing full support taking shelter under pretext of operating conditions limiting their capabilities. In this context, there is a need to validate reactive capabilities of generators in a uniform manner to arrive at realistically attainable values which should be used in planning and operation of grid. A write up on reactive capability testing of generators is given in Chapter-7 of this report, .Voltage profile management through reactive power control by coordinated adjustment of tap ratio of generator transformers is also an important area of attention. The task force recommends that full reactive capability of generators should be available for voltage regulation and there should be mechanism to compensate the generator for any loss of active generation in process of providing required reactive support.

10.6.4 Additionally arrangements may need to be made for allowing operation of hydro generators in synchronous condenser mode. In fact, the CEA (Technical Standards for connectivity to grid) Regulation 2007, specifies synchronous condenser operation as a desirable feature in hydro generators of 50MW and above. To encourage synchronous condenser operation of hydro generators, CERC may like to consider some tariff incentives to these generators.

10.7 **LOW VOLTAGE PROBLEM:** Certain parts of the Northern grid specifically in Punjab, Western Uttar Pradesh, Uttarakhand & J&K face severe low voltage problems especially in July to Sept. in Punjab and during winter months in the hill states.. There is need for installation of adequate shunt capacitors to address the issue of low power factor of incident loads. There is an urgent need to address this issue as otherwise there an apprehension of voltage instability. For further improvement in this area, application of STATCOM, which are state of art equipment for providing dynamic VAR support for better voltage stability, should also be considered.

10.8 **IMPORT LIMIT FOR NORTHERN REGION FOR JULY 2013:** System Studies for peak demand scenario of July 2013 were carried out for cases of import by Northern Region varying from 8200MW to 11300MW. Studies were carried out for base cases, all critical contingency cases. The studies have established that under normal non-contingent conditions, Northern Region can import up to 9750 MW in a reliable manner and the system would remain secure under all critical ‘N-1’ as well as ‘N-1-1’ contingency outages as per planning criteria.

10.9 Power Evacuation from Mundra area of coastal Gujarat and Operation of Mundra – Mahendragarh HVDC link

Three large power stations viz. APL Mundra, CGPL Mundra and Essar Vadinar, with an aggregate capacity of close to 10,000 MW have come up near Mundra in coastal Gujarat. The Mundra area in Kutch Gujarat is also a high wind zone with substantial wind generation capacity which peaks during the April-August period. Power dispatch on the Mundra-Mahendragarh HVDC bi-pole line is being restricted 1500MW factoring 20% overload capacity of HVDC terminals. Dispatch restriction on this HVDC link also constraints other dispatches from Mundra complex. System Protection Schemes (SPS) have been installed at APL Mundra to take care of the eventuality of tripping of any of the lines from the Mundra complex. Safe operating limit evaluated factoring SPS scheme and integrated operation of HVDC and AC system, would give increased dispatch with enhanced security. Higher dispatch on this line would also facilitate achieving higher grid security. In a situation, like the one which caused grid disturbance on 30th and 31st July, 2012, increasing dispatch on Mundra – Mahendragarh HVDC line could have been helpful.

It may further be noted that a similar HVDC line of 2000MW capacity from Talcher STPS to Kolar in Southern region has been constructed by Powergrid for evacuation of 2000 MW capacity. This link has subsequently been upgraded to 2500 MW by providing more cooling on the converter transformers and additional filters for the enhanced capacity. The link is operated to its full capacity as and when required. For 'N-1' contingency of outage of a pole, relief is made available through SPS by load relief from constituents in Southern Region and tripping of units at Talcher.

The Mundra – Mahendragarh HVDC line connects Western region, which has surplus power, and Northern region, which has high load during summers on account of weather beating loads as well as agricultural loads of Kharif crops in Haryana, Punjab and Western UP. In the interest of both the regions, the Mundra – Mahendragarh bi-pole needs to be operated with enhanced dispatch.

10.10 DATA TELEMETRY / PHASOR MEASUREMENT:

10.10.1 Real time data is vital for taking decisions during grid operation. Though there are Regulatory provisions putting the responsibility of providing telemetry to the Load Despatch Centre on the individual users who get connected to the grid, relevant data from a number of Generating Stations / Substations is still not available at the LDCs. RLDSs have taken-up the issue with CERC through individual petitions. However, this is a long discussed issue in which desired success has not been achieved even after more than two decades of efforts,. The Task Force is of the view that a pragmatic approach in ensuring data availability is needed. Effective solution would be to have an integrated approach with single agency responsibility.

10.10.2 The Task Force also deliberated upon the benefits of the scheme for enhancement of data acquisition through synchro-phasor based WAMS, employing PMUs and it emerged that there was a need for understanding the benefits and development of applications related to synchro-phasor based monitoring system. Once the systems are implemented and applications using this data are developed, load dispatchers will have a better overview of real time security parameters and operational system security is expected to improve significantly

10.11 TUNING OF POWER ELECTRONIC DEVICES AND PSS

10.11.1 The Indian power network has several HVDC links and FACTS devices.. The HVDC and FACTS devices have controllers embedded in them to take advantage of their capability to assist in stabilising the network during disturbed conditions. These controllers were tuned during their commissioning phase as per network configuration as envisaged at that stage. However, while the network has been expanding, only occasional re-tuning of some of the controllers has been done on specific requirement but no comprehensive retuning of HVDC/FACTS controllers has been undertaken. Some of these systems like the 2 x 250 MW, Vindhyachal back-to-back link and the Rihand - Dadri 1500 MW HVDC bi-pole were commissioned in the late 80's/ early 90's and the grid in which they are operating today is significantly different from that for which their controllers were tuned. For ensuring their optimal support for grid stability, all these devices should be re-tuned corresponding to simulation of updated network and in future, re-tuning at interval of 3-4 years should also be done.

10.11.2 As these studies are intricate requiring experience of different philosophies and involves specialized dynamic modeling, the review and study may be entrusted to a reputed independent agency while the implementation of the tuning in the respective plants be entrusted to the respective suppliers under a suitable AMC or Service contract.

10.11.3 Apart from the HVDC and FACTS controllers, we also have several Power System Stabilizers (PSS) as part of the generators installed in the network. These PSS are critical for damping the local area oscillations and imparting stability to the networks. Their correct tuning will also enhance the capability of the other HVDC and FACTs controllers in imparting overall/ inter-area stability in an effective manner. Necessary exercise to retune PSS should be undertaken at interval of 3-4 years or even earlier depending on network additions in vicinity of specific generators.

10.12 PROTECTION SYSTEM AUDIT AND RELAY SETTINGS

10.12.1 The Enquiry Committee under Chairman, CEA which analyzed the grid disturbance recommended an extensive review and the audit of the protection system. Towards this exercise, the Task Force constituted a sub-committee comprising engineers from CTU, STU, NTPC, Tata Power, ABB and IPPs which. The protection sub-committee, after detailed deliberations, submitted its report covering recommendations on methodology for relay settings, format for audit data & check list for protection audit and on protection system management issues. The recommendations of the protection sub-committee are given in Chapter-9 of the report. The sub-committee is further in process of carrying out a case study for calculations of relay settings and a report thereon will be submitted shortly. This case study may serve as model for calculation of relay settings in future by various utilities.

10.12.2 It is suggested that all utilities should follow the guide lines given in this report for relay setting and protection coordination and get their protection system audited as per the format and checklist specified.

10.12.3 There is also a need for creating and maintaining data base of relay settings. Data regarding settings of relays in their network should be compiled by the CTU and STUs and furnished to the RLDC and SLDC respectively and a copy should also be submitted to RPC for maintaining the data base.

10.12.4 Audit of protection system should be made mandatory by the CERC and SERC's through specific regulations or by specifying in the Grid Codes. The regulations may include submission of audit report by CTU/STUs/Transmission Licensees to NLDC/RLDCs/SLDCs and also to RPCs.

10.12.5 The Task Force is of the opinion that an Internationally reputed consultant may be appointed to carry out studies to determine the relay settings for the complete network at 220kV and above and also carry out the settings at site in coordination with the CTU and STU's. The comprehensive exercise should be completed in a time bound manner in the next one year.

10.12.6 There is also a need for periodic review of the trippings and settings of the relays and their coordination. The Regional Power Committee which is mandated to discuss issues relating to coordination of grid operation among the various utilities in the Region should on a quarterly basis review the protection & relay coordination issues and ensure implementation of necessary modifications in the relay settings.

10.12.7 The Task Force has also observed that many of the utilities do not possess well trained and dedicated group to carry out studies for calculations for relay settings. The Task force strongly recommends that a dedicated group is required to be constituted and trained in all Utilities to carry out computer aided studies for relay settings. It also recommends that for settings of critical transmission lines and corridors the relay setting calculations be validated by simulations on the Real time digital simulator (RTDS) available with CPRI and PGCIL.

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