National Transmission & Despatch Company Ltd.

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

No. 923-926/DMD(SO)/NPCC

October 31st, 2023

Registrar
National Electric Power Regulatory Authority (NEPRA)
Islamabad

Dear Sir,

Pursuant to section OC 5.4.13 of the Grid Code, the Operating Reserves Policy (ORP) is submitted as **Annex A**. Operating reserves, reactive power and black-start services are collectively referred to in the Grid Code as *Ancillary Services*.

Operating Reserves are required for two purposes:

i. frequency regulation under normal operations (secondary reserve, also known as regulating reserve) to counter the natural variation in generation and demand, and
ii. frequency containment (primary reserve) and frequency restoration (secondary reserve and tertiary reserve) following a large disturbance.

It is important to note that generators can only provide upward regulation when running at part-load. Therefore, part-load adjustment costs (PLAC) are an unavoidable feature of provisioning operating reserves from power plants. Consequently, the current billing mechanism that penalises *failure-to-achieve-dispatch-level* (FTADL) should not be applicable to generators providing operating reserve as the dispatch level of these generators would be continuously changing to steer the system frequency towards the target frequency band. Therefore, the billing and settlement mechanism and the regulatory framework need to be addressed if load-frequency control is to be implemented in compliance with the Grid Code.

Presently, in the absence of frequency containment and restoration reserves, the loss of a 600 MW generator triggers load shedding from system protections, i.e., automatic under-frequency relays and rate-of-change-of-frequency (ROCOF) relays. Without frequency response from generators, load shedding is the only counter measure. The grid stations where load shedding takes place after a frequency event depends on the ROCOF, the frequency nadir and the response time of protection relays and allied equipment. The new system configuration can change the angular separation of northern and southern generators, potentially creating rotor-angle instability that can split the system into two islands. The new system configuration changes reactive power flows in the system, which may cause voltage instability in parts of the network and trigger HVDC blocking further endangering system security.

The analysis finds the primary reserve requirement to be 890 MW in summer and 674 MW in winter, to be shared between the control areas within the synchronous power system. Primary reserve is typically provided by synchronous machines operating on free governor mode of operation (FGMO). However, the analysis shows that FGMO may not be sufficient for frequency containment in winter in an operational scenario with higher penetration of wind and solar energy. This is due to the fact that inverter-based generators (IBG) such as wind and solar do not contribute any inertia to the system. In this case, fast frequency response from 500 MW of battery-energy storage systems (BESS), i.e., full power output within 200 milliseconds is the only viable technical solution to ensure system security. The BESS capacity may be split into 250 MW in the north and 250 MW in the south for efficient frequency control across the north-south interfaces.

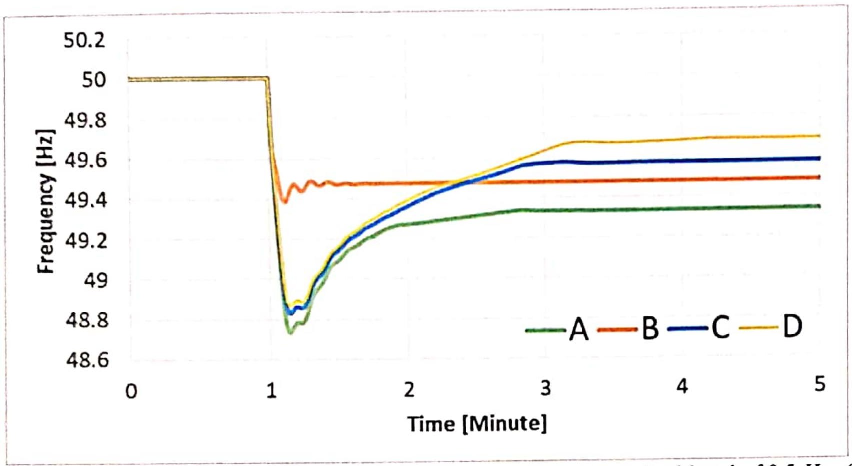


Figure 1: System frequency response during winter: (A) governor dead band of 0.5 Hz; (B) integration of 500 MW BESS in previous case; (C) governor dead band of 0.2 Hz and (D) governor dead band of 0.05 Hz)

Secondary reserve has a dual function – to balance supply and demand during normal operations, and to relieve primary reserve and restore the system frequency to 50 Hz after a contingency event. The importance of secondary reserve increases with higher penetration levels of wind and solar energy, as the natural variation of renewable resources increases the requirement for upwards and downwards regulation (i.e., balancing energy). Secondary reserves need to be equally distributed between the northern and southern generators to maintain the tie-line bias and reduce the area control error (ACE) between regions.

The ramp rates of power plants are an important consideration when dimensioning secondary reserves. A study commissioned by the World Bank (2020) found that ramp rates of thermal power plants as agreed in the PPAs are very low compared to international benchmarks and below the technological capabilities. The System Operator's analysis shows that the generation cost would be lower and system security higher if secondary reserves are provisioned at fast ramping power plants such as Hub Co. compared to baseload coal power plants.

Ali Zain Banatwala
Deputy Managing Director (System Operation)

Copy to:

- Secretary, Power Division, Ministry of Energy, Islamabad
- MD, NTDC, WAPDA House, Lahore
- CEO, CPPA-G, Islamabad

Operating Reserves Policy (2023)

National Power Control Center
National Transmission & Despatch Company Limited

List of Acronyms and Abbreviations

APE	Absolute Percentage Error
AC	Alternating Current
BESS	Battery Energy Storage System
CC	Connection Code
FFR	Fast Frequency Reserves
FGC	Free Governor Control Action
β	Frequency regulation characteristics
GW	Gigawatt
GWh	Gigawatt-hour
GWs	Gigawatt-second
MAPE	Mean Absolute Percentage Error
MW	Megawatt
MWh	Megawatt-hour
MWs	Megawatt-second
NPCC	National Power Control Center
NTDC	National Transmission and Despatch Company
OC	Operation Code
ROCOF	Rate Of Change Of Frequency
SDC	Scheduling and Dispatch Code
SO	System Operator
UFLS	Under frequency Load Shedding
VRE	Variable Renewable Energy

Executive Summary

The need for operating reserves in a power system arises due to the inherent challenges in maintaining a reliable and stable electricity supply. These challenges include fluctuations in demand, unexpected equipment failures, and the increasing integration of variable renewable energy (VRE) sources, all of which can jeopardize the grid's operational integrity.

The challenge for power system operators is to ensure uninterrupted and reliable electricity supply to consumers, despite the dynamic nature of electricity demand, the potential for unforeseen disruptions, and the growing reliance on variable renewable energy sources. Operating reserves are required to address these challenges effectively by providing the necessary capacity and flexibility to maintain supply-demand balance, respond to contingencies, and preserve grid stability.

The dynamic and delicate equilibrium between active power demand and supply is reflected in the continuous deviation of the system frequency from its nominal value of 50 Hz. System operators must continuously manage the system frequency in order to maintain the stability and operational integrity of the power grid. The demand for active power is dynamic and constantly changing, varying throughout the day and across seasons due to industrial processes, residential consumption patterns, and weather conditions. The demand is met by supplying the electricity through fossil fuel-based power plants, hydro power plants, nuclear reactors, and renewable energy sources like wind and solar. Power plants are designed to provide a reliable and consistent output of active power, but they must also be capable of responding to changes in demand. This flexibility is crucial to match supply with demand in real-time, especially during periods of high demand or unexpected fluctuations.

To maintain the balance between supply and demand, the Grid Code mandates a combination of generation capacity and operating reserves. Generation capacity consists of power plants that are online and ready to produce electricity. Operating reserves are additional resources, typically maintained at various levels (normal operation reserves and contingency reserves), that can be rapidly deployed to address sudden changes in demand or unexpected equipment failures. These reserves act as a safety net, ensuring that the grid remains stable and reliable even when faced with disruptions or variations in demand or renewable generation. Accurate forecasting, efficient dispatch of generation resources, and the availability of operating reserves are key elements in maintaining this balance and ensuring the uninterrupted delivery of electricity. The modern power grid's ability to adapt to changing conditions and meet the dynamic needs of society is essential for powering our increasingly electrified world.

Grid Code 2023

NEPRA Grid Code 2023 is designed to ensure the reliable and efficient operation of the grid and meet the challenges of the modern power system, and to facilitate the integration of renewable energy sources. The grid code has defined the frequency bands for normal and contingency conditions and the control actions along with the time scale, i.e., primary, secondary and tertiary control. Primary control action is an automatic response from loads and generators which depends on load damping, governor dead bands and governor droop settings. Secondary and tertiary control are corrective actions that normalize the system frequency and restores primary reserves for future use.

As per the Grid Code, the System Operator (SO) is responsible for the Safe, Secure and Reliable operation of the National Grid. The SO is required to specify the requirement of System Services are essential to the proper functioning of the National Grid and have complete control for reliable power system operations (OC – 5). The grid code specifies the objectives for secure power system operation in OC-5:

- To establish a policy to ensure frequency control capability in the national grid for operational control by the SO, and to set out appropriate procedures to enable the SO to control the national grid frequency and maintain it within the limits specified in this operational code of grid code
- To set out the types and amounts of reserve, as provided in a number of time scales, which make up the operating reserve that the SO may make use of under certain operating conditions for frequency control;
- To describe the various time scales for which operating reserves are required, the policy which will govern the dispatch of the operating reserves, and the procedures for monitoring the performance of generating units and other operating reserve providers.

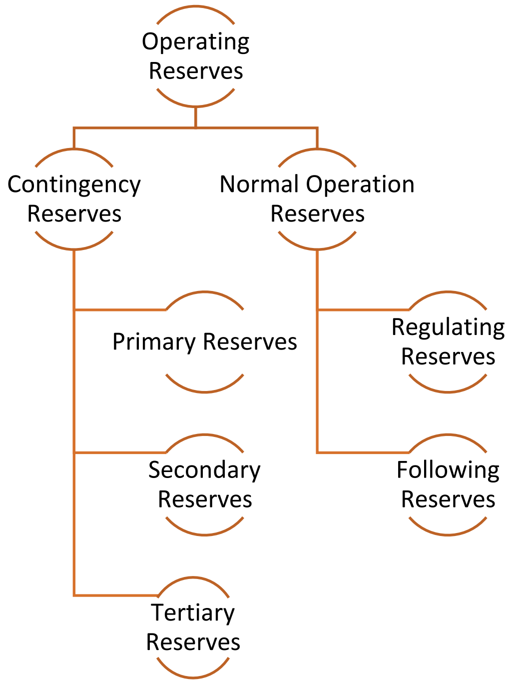
To achieve the aforementioned objectives, and in compliance of the Operating Reserve Policy (OC 5.4.13) requirement whereby the SO is required to determine the reserve requirements to ensure system security, this study has been carried out by modelling load-frequency control for Pakistan's power system in DigSilent Power Factory.

Operating Reserves

Operating reserves are categorized as contingency and normal operating reserves. Contingency reserves are the reserves activated after an N-1 contingency whereas regulating reserves are used to minimize the real-time power imbalances arising due to load or VRE forecasting error. Contingency reserves are further categorized as primary, secondary and tertiary reserves while normal operating reserves are categorized as regulating reserves (secondary reserves) and following reserves (tertiary reserves). The amount of reserve (in MW) required for secure operation is identified through simulation modelling and real-time operational requirement.

Contingency Reserves

Contingency reserves are specifically provisioned to provide load-frequency control following unexpected events or contingencies that disrupt the normal operation of the grid. These reserves are essential for maintaining system reliability during unforeseen circumstances, such as sudden equipment failures, unexpected generation or transmission outages, or extreme weather events. The need for contingency reserves is identified through simulation models in which the national grid is modelled for frequency control studies taking in account the inertia (MWs) of generators, speed governor control settings, turbine control models and load damping. The study has analyzed four base cases; summer peak, summer off-peak, winter peak and winter off-peak, with current generation and four cases for summer peak, summer off-peak, winter peak and winter off-peak with the integration of 2500 MW of solar PV and 1000 MW of wind power. The case studies are analyzed for Primary and Secondary control.



Primary Reserves

The need for primary reserves is evaluated by analyzing each case for four scenarios; (A) governor dead band of 0.5 Hz (current state of most of the power plants), (B) integration of 500 MW Battery Energy Storage System (BESS) system in previous case, (C) governor dead band of 0.2 Hz and (D) governor dead band of 0.05 Hz (as per grid code requirement) for N-1 contingency when nuclear power plant K-2 of 1040 MW capacity trips. The following are the outcomes:

- Power system frequency is maintained as per Grid code requirement through provision of ancillary services that are essential for stable, reliable, and secure power system operations. The study shows that primary reserves of ±890 MW are needed during summer and ±674 MW during winter when the system is operated as per grid code requirement. The generating units with FGMO within NTDC and KE system will share the reserve burden. Considering the load demand and available generation, KE shall contribute 10% of the primary reserves and NTDC contribute 90% of the required primary reserves. The reserves need to be maintained on multiple generating units for effective frequency regulation, with overall frequency regulation characteristics (β) of 6133 MW/Hz, i.e., 5518 MW/Hz in NTDC network and 615 MW/Hz in KE network (Calculations provided in Annexure 2).
- The reserves for primary control have to be distributed among all major power plants depending on their capability of providing primary reserves. The study provides the PPA 8.3 Turbine Governor Operation tests that shows that all major power plants are capable of providing desired response (Annexure 2).
- Power system operates more securely with governor dead band of 0.2 Hz or 0.05 Hz, as timely response from the generating units stabilizes the frequency. Keeping the real-time issues faced by the power plants in account, the study suggests that initially all the power plants need to maintain their dead band at 0.2 Hz and later modify it to 0.05 Hz as per grid code requirement.
- Limited online generating units in winters reduces the system inertia resulting in high ROCOF during contingency event. In future with increasing integration of VREs

more thermal power plants will be replaced and thus the power system will have less inertia to handle contingency events. Fast regulating reserves and synthetic inertia is required especially with integration of VREs that can be provided only from the BESS.

- When 500 MW of primary reserves are maintained on BESS, fast activation of reserve power supports the power system effectively especially in winter season. Low system inertia at the event of contingency can lead to the instability or black out.

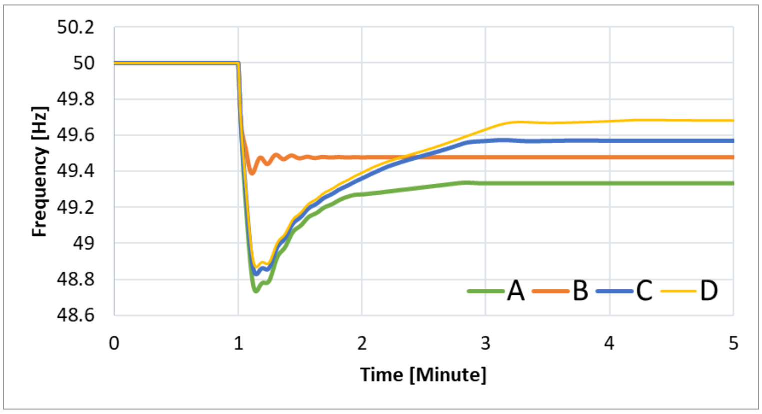


Figure 0-1: System frequency response during winter - (A) governor dead band of 0.5 Hz; (B) integration of 500 MW Battery Energy Storage System (BESS) system in previous case; (C) governor dead band of 0.2 Hz and (D) governor dead band of 0.05 Hz)

- The availability of the BESS minimizes the regulating burden on power plants and enable system operator to operate base load power plants as per merit order without impacting the system security in real-time during contingency events. 500 MW of BESS can provide frequency regulation characteristics (β) of 2000 MW/Hz compared to 6613 MW/Hz from 12266 MW of generators equipped with FGMO.

Secondary Reserves

Secondary control requirements are evaluated during N-1 contingency for base cases and cases with increased VREs against two scenarios, i.e., when secondary reserves are maintained on available generating units and when secondary reserves are maintained on fast ramp power plants. The following are the outcomes:

- Activation of secondary reserves restores the system frequency and the primary reserve for future use. The restoration depends on the ramping capability of generating units.
- Secondary reserves equal to the largest contingency event need to be maintained all the time. Presently, NTDC system require secondary reserves of 1040 MW for secure operation of the power system.
- When secondary reserves are maintained on merit order power plants, they will be operated close to minimum power level and will be re-dispatched in case of power imbalances. Once AGC is available (SCADA 3) the redispatch will be continuous based on the deviation of frequency and tie line flow from their nominal level.
- Secondary reserves when maintained on fast ramping generating enhances system security. The merit order generating units will be operated as base load power plants and fast ramping generating units will be used for secondary dispatch.

- The study simulates two scenarios for each base case and VRE integrated case. Scenario A maintain secondary reserves on merit order power plants and Scenario B maintain secondary reserves on fast ramp power plants. The financial analysis is provided below, which shows that generation cost will be lower if reserves are maintained on fast ramp power plants and the system security will maintained as well.

Table 0-1: Generation Cost for Base case scenarios

	Scenario A		Scenario B	
Base cases	Total Generation [MW]	Generation Cost [PKR/hour]	Total Generation [MW]	Generation Cost [PKR/hour]
Summer Peak	27,214	352,732,674	27,214	335,862,377
Summer Off-peak	22,470	248,828,452	22,470	248,739,958
Winter Peak	15,593	197,758,886	15,593	194,977,734
Winter Off-peak	8,268	73,280,525	8,268	76,400,373

Table 0-2: Generation Cost for VRE integrated case scenarios

	Scenario A		Scenario B	
VRE Integrated cases	Total Generation [MW]	Generation Cost [PKR/hour]	Total Generation [MW]	Generation Cost [PKR/hour]
Summer Peak	27,214	327,563,804	27,214	318,783,680
Summer Off-peak	22,470	229,131,142	22,470	223,731,675
Winter Peak	15,593	172,389,615	15,593	176,850,115
Winter Off-peak	8,440	77,465,440	8,440	70,378,564

- Grid code specifies the Minimum Load, Ramp up/down capability of thermal generating units however currently most of the power plants do not meet the criteria. The criteria specified in the CC 6.2.1 (h) is provided in Table below. With increasing VRE integration, fast ramping generating units as provided in below table are necessary for secure operation of the power system.

Tertiary Reserves

Tertiary Frequency Control is used to restore the reserves that were used during Primary and Secondary Frequency Control. Reserves may be restored using re-dispatch, commitment of resources, or establishing new Interconnector schedules. Restoring these reserves completes the repositioning of the National Grid so that it is prepared to respond to a future loss-of-generation event.

Table 0-3: Contingency Reserve Requirement

Reserves Type	Quantum [MW]	Time Scale	Description	Obligation
Primary reserves	890	5 - 20 seconds and sustainable till activation of secondary reserves	Free Governor control	Online generating units equipped with speed governors and operating below maximum or above minimum operating level. 6133 MW/Hz frequency regulation to be maintained for effective activation.
Secondary reserves	1040	1 - 20 minutes and	AGC or Redispatch	Fast ramping online generating units

		sustainable till activation of tertiary reserves		
Tertiary Reserves	1000	30 minutes to 1 hour	Redispatch	Online and offline generating units

Normal Operating Reserves

Regulating Reserves

Regulating reserves are the secondary reserves held by control areas to balance normal deviations of frequency and interchange schedules that occur based on load and generation changes. The imbalance during normal operating conditions arises due to the forecast error in load demand, wind power and solar power. The requirements can either be based on empirical analysis or by probabilistic methods. In this study the allowable forecast error in grid code is taken as reference, however, the real-time forecast error is quite high.

As per the grid code, absolute percentage VRE forecast error for hour-ahead intraday generation forecasts is 10% (SDC 1 Appendix — E) and for the load demand the mean absolute percentage error is 3% (OC 2.8.2). The regulating reserves will vary and the quantum depends on the load and VRE forecast which increases with increasing integration of VREs. The tables below provide the reserve requirement for the considered case studies.

Table 0-4: Regulating Reserves Requirement (Base cases)

	Load Forecast [MW]	Reserve (load) [MW]	Wind Forecast [MW]	Reserve (wind) [MW]	Solar PV forecast [MW]	Reserve (Solar) [MW]	Total Reserves [MW]
Summer Peak	26,045	±806	1,331	±133	315	±33	±972
Summer Off-Peak	21,455	±664	900	±90	150	±16	±770
Winter Peak	14,427	±446	432	±43	0	±0	±489
Winter Off-Peak	7,702	±238	178	±18	0	±0	±256

Table 0-5: Regulating Reserves Requirement with increased VRE integration

	Load Forecast [MW]	Reserve (load) [MW]	Wind Forecast [MW]	Reserve (wind) [MW]	Solar PV forecast [MW]	Reserve (Solar) [MW]	Total Reserves [MW]
Summer Peak	26,045	±806	2,052	±228	1,915	±213	±1247
Summer Off-Peak	21,455	±664	1,386	±154	1,150	±129	±947
Winter Peak	14,427	±446	1,032	±115	1,510	±168	±729
Winter Off-Peak	7,702	±238	592	±66	1,110	±123	±427

Following Reserves

Following Reserve are tertiary reserves needed to accommodate the variability and uncertainty that occur during normal conditions during to variation in VRE generation and load. The Following Reserves are not faster than economic dispatch optimization, and does not require automatic centralized response.

Optimum Reserve Requirement

Secure power system operation requires both contingency reserves and the normal operating reserves. However, keeping such huge quantum will increase the operating cost. Therefore, this study recommends maintaining sizeable reserves among secondary contingency and regulating reserves for secure power system operations. Primary reserves need to be distributed on the generating units operating in the north and south region of the country with the desired frequency regulation characteristics (β). Secondary reserves also needed to be distributed between north and south regions keeping power flows on HVDC and HVAC network in account. Secondary reserves need not be maintained on fast ramping generating units for operational security. On the other hand, keeping secondary reserves on base load power plants negatively impacts the system security and also increases generation costs. The reserve requirement is dynamic, depending on the VRE penetration and operating conditions. The power system operator should specify the reserve requirement seasonally, modifying it as and when required based on VRE penetration and operating conditions of the power system.

Secure power system operation also depends on system inertia. Low system inertia results in high frequency variations, particularly when fewer generating units are operating due to low power demand. Higher penetration of VRE will have a proportionately larger impact on system inertia as the inverter-based generation (which does not provide inertia) will replace synchronous machines. In this case. fast frequency reserves (FFR) and synthetic inertia will be required. FFR/synthetic inertia can be provided by battery energy storage systems (BESS). Installation of BESS at multiple locations (at least one in the north and one in the south) can support the system in maintaining system frequency and voltage stability.

System Operator has taken up Grid Code compliance of frequency regulation with the relevant Generating Units and CPPA-G. One major concern highlighted by Power Plants was that in case primary frequency response is activated in accordance with the terms of Grid Code 2023 it will result in deviation of actual delivered energy from Dispatch instructions. However, there is no downward compensation of net dispatch & delivered energy and CPPA-G charges liquidity damages incase dispatch level is below instructed limits. Matter was taken up with CPPA-G & it was agreed that issue of dispatch deviations will be resolved in the respective Power Purchase Agreements after approval of reserves management policy.

It should be noted that this is an indicative policy based on dynamic stability analysis of the interconnected power system. The weekly requirement for reserves will be calculated based on prevailing system conditions.

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1 Introduction

Power systems are the backbone of modern civilization, providing a continuous and reliable supply of electricity to homes, industries, and businesses. Maintaining the secure operation of a power system is of paramount importance to prevent blackouts, ensure the stability of the grid, and meet the ever-increasing demand for electricity. One critical aspect of secure operation is frequency control, which plays a pivotal role in keeping the power system functioning efficiently and reliably.

A power system consists of various interconnected components, including power generators, transmission lines, substations, and distribution networks. These components work in unison to deliver electrical energy from power plants to end-users. The seamless operation of this complex network requires careful coordination and control to ensure that supply and demand remain balanced. Frequency control is a fundamental aspect of power system operation. In an alternating current (AC) power system the frequency of electricity is set at 50 Hertz (Hz). The frequency of the grid is a direct indicator of its stability. Any deviation from the nominal frequency can have severe consequences. Frequency control is essential to ensure that all interconnected generators operate in synchrony and able to share load and maintain system stability.

Frequency control plays a crucial role in balancing the supply and demand for electricity. If the demand for power exceeds supply, the frequency tends to decrease, and vice versa. Therefore, grid operators continuously adjust generation to match demand, maintaining the frequency close to the nominal value. Several mechanisms and control strategies are employed to maintain frequency within acceptable limits.

- Primary Frequency Control is an essential first-line defense against frequency deviations. Generators are equipped with speed governor that respond to changes in frequency by adjusting their output. These controllers act within seconds to stabilize the grid in case of contingencies.
- Secondary Frequency Control is responsible for restoring the grid's frequency to its nominal value over a slightly longer timeframe, typically in tens of minutes. This involves more significant adjustments to generator outputs. The secondary frequency control activates the reserves in case of contingencies or to mitigate the imbalances arising due to forecast error.
- Tertiary frequency control is a more extended-term control strategy, often taking 30 minutes to hours to mitigate the larger and sustained imbalances due to forecast error or contingencies.

While frequency control is a well-established practice, it faces several challenges in modern power systems. The increasing integration of renewable energy sources, such as wind and solar power, poses challenges for frequency control. These sources are variable and intermittent, making it more challenging to maintain grid stability. Also, with interconnections the challenges associated with frequency control also increase. The potential for cascading failures and the need for real-time monitoring and control become more critical. The system frequency is controlled through different operating reserves. The reserves are the extra generation maintained on the generating units. The operating reserves depending on their response can be identified as contingency reserves and the normal reserves. Further classification of these reserves is provided below:

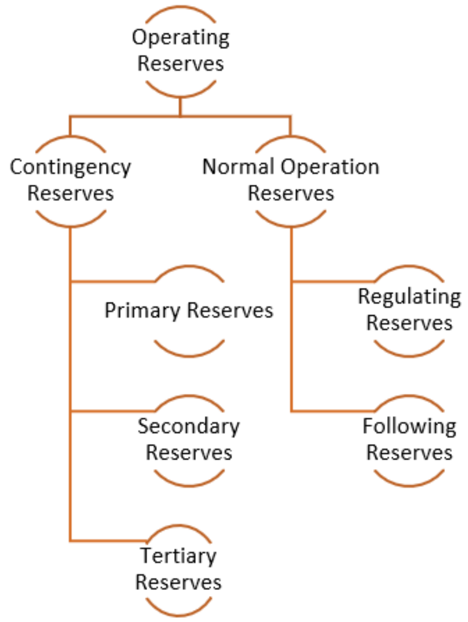

Figure 1-1: Operating Reserves

This study identifies the required reserve for national grid through a simulation model modelled in Power Factory DigSilent. The NTDC and KE system is modelled for frequency control studies only taking in account the generators inertia, speed governor control settings and turbine control models in account and ignores the transmission system modelling. It is important to mention here that the study didn't model the system protection relays, i.e., ROCOF and Under frequency Load Shedding (UFLS) as the operation of these relays impacts the transmission line flows.

For primary reserves, the study has analyzed the four base cases, i.e., summer peak, summer off-peak, winter peak and winter off-peak, during N-1 contingency when nuclear power plant K-2 trips. The study then analyzed the cases when 2500 MW of solar PV and 1000 MW of wind will be integrated in the power system replacing the thermal power plants. The study takes in account impact governor dead band settings considering the real-time issues faced by the power plants. The need of fast reserves through 500 MW of BESS is also analyzed. The need for secondary reserves is analyzed through the set of generating units where the reserves are maintained on merit order generating units or reserves are maintained on fast ramp rate generating units. The scenarios are analyzed technically and financially for the base cases and the case with high integration of VREs. The analyses highlight the need of operating of operating reserve (primary and secondary) and the issues in real-time power system operations regarding frequency control.

This report is structured as follows. Section 2 will detail the requirement for frequency regulation as in the approved grid code 2023, Section 3 will discuss the primary reserve requirement for base cases during N-1 contingency whereas the Section 4 will discuss the primary reserve requirement for operating cases with increased integration of 2500 MW solar PV and 1000 MW of wind during N-1 contingency. Section 5 and Section 6 will discuss the reserve requirement for secondary control considering the ramping capabilities of thermal power plants for the base cases and increased VREs respectively. Section 7 will highlight the tertiary reserve requirement. The detail the regulating reserves required for tacking the load and VRE forecast error is presented in Section 8 and also highlights the constraints that can be applied on VREs for secure operation of the power system for future operations. The policy recommendations based on this study are provided in Section 9.

2 Grid code Requirement for Frequency Regulation

Grid codes play a crucial role in ensuring the secure and reliable operation of power systems. Their effectiveness in achieving this goal depends on several factors, including their design, enforcement, and adaptability to changing grid conditions. In this regard, NEPRA Grid Code 2023 is a set of guidelines, rules, and procedures that all participants in the Pakistani power system must follow. It is designed to ensure the reliable and efficient operation of the grid and meet the challenges of the modern power system, and to facilitate the integration of renewable energy sources.

For secure operation of the power system, the Operation Code (OC) section of grid code defines the frequency ranges. As per OC 5.4.4, the integrated Power System shall be so planned and operated that the System Frequency remains within the following limits provided in Table 2-1.

Table 2-1: Frequency limits during different operating conditions

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

The System Operator (SO) shall coordinate with all the users connected to Transmission System in order to maintain the System Frequency within the Target System Frequency (50 ± 0.05 Hz). However, allowed to operate in Frequency Sensitive Band (49.8 Hz - 50.2 Hz) while ramping up generation and load pick-up, and in Tolerance Frequency Band (49.5 Hz -50.5 Hz) which are protected periods of operation of the system and in Contingency Frequency Band (49.3 - 50.5 Hz), which is the maximum expected absolute value of the instantaneous Frequency after the occurrence of an imbalance, beyond which SO shall deploy emergency measures such as Demand Control or Automatic Low Frequency Demand Disconnection. A Significant Frequency Disturbance Event is deemed to have occurred if the Frequency falls below 49.3 Hz or rises above 50.5 Hz.

Instantaneous Frequency excursions are to be handled in the following manner:

a) In the event of a single contingency, the Power System Frequency must be maintained within 'Tolerance Frequency Band within 5 minutes of the excursion, and to within the "Frequency Sensitive Band" within 10 minutes of the contingency.

b) Instantaneous Frequency excursions outside the Contingency Frequency Band" shall be handled in such a manner that System Frequency returns to "Contingency Frequency Band" within 60 seconds. System Frequency returns to "Tolerance Frequency Band" within 5 minutes, and within the Frequency Sensitive Band' within 30 minutes.

c) For avoidance of doubt, the operating ranges mentioned above are the limits for System Frequency which are to be maintained by the SO to comply with NERPA Performance Standards to ensure Power Quality in Normal State.

2.1 Frequency Control Description

The Grid code species the Frequency Control in three interlinked stages, namely: Primary Frequency Control, Secondary Frequency Control and Tertiary Frequency Control.

Primary Frequency Control

Primary Frequency Control takes place in a time scale immediately following a change in frequency that reaches its maximum value within 10 seconds and is sustainable up to 30 seconds, and is achieved by automatic corrective responses to frequency deviations occurring on the Transmission System. This automatic correction mainly arises from system inertia of rotating synchronous generators, natural frequency demand relief of motor load (load damping) and automatic active power (MW) output adjustment of synchronous generators (governor control). The need for the governor control mode lies in the fact that the synchronous should be able to correct their own frequency when a disturbance occurs in the system, considering the difference of the speed of the Generating Units depending on the type of technology. Generating units shall not depend on any order or instruction, issued by the SO either manually or electronically, to modify the amount of Energy injected into the Transmission System (MW) to correct their frequency.

As per OC 5.4.7.2, All Generating Units when Synchronized to the Transmission System shall be able to provide:

a) Free Governor Control Action (FGC) through a Governor Control System, to maintain System Frequency within the prescribed limits provided in this OC;

b) The Active Power Frequency Response shall be capable of having a Governor Droop between 2% and 12%. The default Governor Droop setting, unless something different is required by the SO and reflected in the Connection Agreement, shall be 4%;

c) No time delays other than those necessarily inherent in the design of the Governor Control System shall be introduced;

d) A Frequency dead band of no greater than 0.05 Hz may be applied to the operation of the Governor Control System as shown in Figure 5. The design, implementation and operation of the Frequency dead band shall be agreed with the SO prior to commissioning of the Generating Unit/Station.

The OC 5.4.7.3 defines the "Primary Operating Reserve" as the amount of Frequency Response in MW that the synchronized Generators can provide cumulatively under Free Governor Control.

Secondary Frequency Control

Frequency deviations, outside the frequency sensitive are corrected through the use of Secondary Frequency Control. Secondary Frequency Control takes place in the time scale from 5 seconds following the change in Frequency and achieves its maximum value within 30 seconds which is sustainable up to 30 minutes. Secondary Frequency Control acts directly on the active power (MW) output of participating synchronous machines. Frequency Control may be assigned to a single Generator or Generating Unit and further actions from other Generators shall be coordinated according to instructions issued by the

SO to obtain the required Frequency response. According to OC 5.4.11.6, SO shall maintain appropriate reserve (headroom) in the participating Generators to allow them to vary their MW Output under Automatic Generation Control.

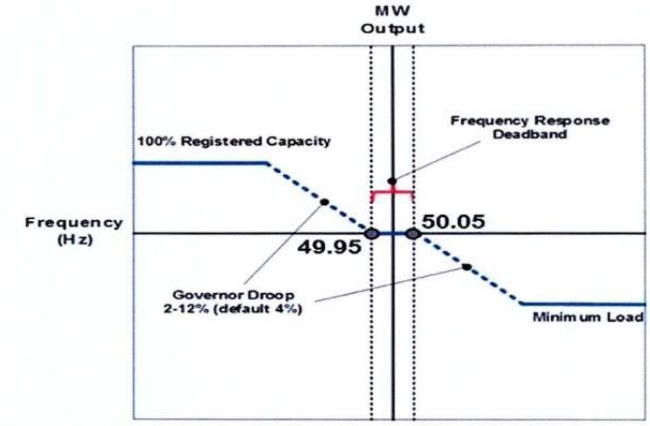

Figure 2-1: Primary frequency control

Tertiary Frequency Control

The goal of Tertiary Frequency Control is to restore the reserves that were used during Primary and Secondary Frequency Control. Reserves may be restored using re-dispatch, commitment of resources, or establishing new Interconnector schedules. Restoring these reserves completes the repositioning of the National Grid so that it is prepared to respond to a future loss-of-generation event.

The summary of the primary, secondary and tertiary frequency is provided in the table below:

Table 2-2: Summary of Primary, Secondary and Tertiary frequency control

Name	Timescale	Description	Type of Operating Reserve	Participants	Quantum
Primary Frequency Control	0 - 10 sec and sustainable up to 30 sec	Free Governor Control/Non-Synchronous Frequency Control	Primary Frequency Reserve	Fitted on all Generators and ESUs, including Embedded Generators and always activated.	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, as per Generators on-bar
Secondary Frequency Control	5 sec - 30 sec and sustainable up to 30 min	Automatic Generation Control (AGC) or secondary Frequency Control	Secondary Frequency Reserve	Fitted on all applicable Generators and activated on SO instructions or AGC	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, equal to the largest synchronized Generating Unit
Tertiary Frequency Control	20 min - 4 hours	Re-dispatch/Synchronization	Replacement Reserve	Re-dispatch/Synchronization of Generators to restore Primary and Secondary Reserves	As per the GCOP for Operating Reserve Requirements. Until such GCOP is developed, equal to the largest Generating Unit
	24 hour ahead to real time		Contingency Reserve		

2.2 Operation Code Obligation

The Operation Code (OC) of the Grid code 2023 specifies the technical and operating criteria, and procedures to be followed by the SO and code participants in the operation of the National Grid during normal and contingency operating conditions. The power system is considered in Normal state when the Single Outage Contingency (N-1) Criterion is met, i.e., all equipment operates in contingency limit, the Operating Reserves are in accordance with the values established as given in OC 5 and the system frequency is within the limits as specified in OC 5.4.4.1. The SO is responsible for the Safe, Secure and Reliable operation of the National Grid and the Code Participants have to follow the technical design and operating criteria and procedures as specified in the Grid Code. The SO is required to specify the requirement of System Services are essential to the proper functioning of the National Grid and have complete control for reliable power system operations (OC – 5). The grid code specifies the objectives for secure power system operation in OC-5:

- To establish a policy to ensure frequency control capability in the national grid for operational control by the SO, and to set out appropriate procedures to enable the SO to control the national grid frequency and maintain it within the limits specified in this operational code of grid code
- To set out the types and amounts of reserve, as provided in a number of time scales, which make up the operating reserve that the so may make use of under certain operating conditions for frequency control;
- To describe the various time scales for which operating reserves are required, the policy which will govern the dispatch of the operating reserves, and the procedures for monitoring the performance of generating units and other operating reserve providers.

To achieve aforementioned objectives, and in compliance of Operating Reserve Policy (OC 5.4.13) requirement where SO have to determine any reserve requirements, including the amount of Primary Operating Reserve, Secondary Operating Reserve and Tertiary Operating Reserve to ensure system security. For such reason, within twelve (12) months of the approval of this Grid Code, the SO shall establish, and maintain permanently updated, GCOP for Operating Reserve Requirements, detailing the methodology to be used to determine the amounts of different types of reserve required by the Transmission System in different operational conditions. The GCOP shall take due consideration, inter alia, the following factors:

a) the relevant SO operating policy in existence at that time;

b) the magnitude and number of the largest generation infeed to the Transmission System, including infeed over Interconnectors, and also over single transmission feeders within the Transmission System, and the amount of Generation that could be lost following a single Contingency;

c) the extent to which Demand Control allowed under the relevant standard have already occurred within the then relevant period;

d) the elapsed time since the last Demand Control Incident;

e) particular events of national or widespread significance, which may justify provision of additional Operating Reserve;

f) the cost of providing Operating Reserve at any point in time;

g) expected demand/VRE generation forecast variability;

h) ambient weather conditions, insofar as they may affect (directly or indirectly) Generating Unit and/or Transmission System reliability;

i) the predicted Frequency drop on loss of the largest infeed as may be determined through simulation using a dynamic model of the National Grid;

j) constraints imposed by agreements in place with Externally Interconnected Parties;

k) uncertainty in future Generation output.

Forecast Accuracy

Grid code has also specified the error margin for the load and variable renewable energy (VRE) forecasts. According to OC 2.8.2, *the performance of the forecasts provided shall be assessed based on the mean absolute percentage error (MAPE) indicators and values provided for different Planning Horizons in Table OC1*. The table is provided below:

Table 2-3: Performance Requirements for Demand Forecast (Table OC1)

Horizon	Resolution	Evaluation Metric	Evaluation Metric Range	Probability Metric and Measurement horizon	Remarks
Day Ahead	Hourly	Daily MAPE	3%	P95 at hourly Basis	Daily MAPE to be less than 3% at least 95% of the hours in a day
Week Ahead (OC 2.5.2)	Hourly	Daily MAPE	3%	P95 at monthly basis	Daily MAPE to be less than 3% at least 95% of the days in a month
Year Ahead (OC 2.4.2 (d))	Monthly	Annual MAPE of the monthly energy values	3%	-	Error between the forecasted and actual energy consumption averaged over 12 months be within 3% range

Also, the SDC-1 Appendix E specifies the forecast error for VREs. *For hour-ahead intraday generation forecasts, the desired forecast accuracy, measured in terms of P95 of the absolute percentage error is 10%. For day-ahead generation forecasts, the desired forecast accuracy is P95 of 15%.*

3 Primary Reserves Requirement for Base Cases during N-1 contingency

This section analyses the frequency response of the power system following an N-1 contingency in four base cases. The details of the base cases are provided below:

Table 3-1: NTDC and KE system load demand and generation during base cases

Sr. No.	Base Cases	NTDC load demand [MW]	NTDC Generation [MW]	KE load demand [MW]	KE Generation [MW]	KE Import [MW]
1	Summer Peak	26,045	27,214	3,383	2,214	1,169
2	Summer off-peak	21,455	22,470	1,530	515	1,015
3	Winter Peak	14,427	15,593	2,536	1,370	1,166
4	Winter off-peak	7,702	8,268	996	430	566

The N – 1 contingency simulated is the loss of largest infeed, i.e., the largest generating unit (K-2). The study provides an analysis on the **rate of change of frequency (ROCOF)**, **frequency nadir** and **steady state frequency** during different operating conditions. Based on these analyses the study provides the requirement of primary reserves (fast frequency reserves) for secure operation of the power system.

3.1 Summer Peak – Base case

For the base case of summer peak, Table 3-2 provides the generation from the power plants along with their inertia and operating reserves. The operating reserves shown here is the difference of the power generated from their capacity. The table specifies the power plants category operating in the NTDC system and the KE system. The NTDC system is generating 27,214 MW in which 1,169 MW of power is exported to KE system while KE system is generating 2,214 MW of generation. The inertia (in MWs) depends on the MW capacity of power plants and frequency regulation characteristics (β) which is provided in MW/Hz. In the operating conditions, the NTDC power system has inertia of 133,013 MWs and β of 9043 MW/Hz. The detailed data of each operating power plants is provided in Annexure 1.

Table 3-2: Power Generation before N-1 contingency (summer peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	8,170	40,845	535	2,391	-	-	-	
Small Hydro	150	512			-	-	-	
Bagasse	100	559			-	-	-	
Nuclear	3,305	20,360			57	531	-	
Thermal	13,844	70,738	1,667	6,653	2,038	9,689	306	1027
Wind	1,331				119	-	-	
Solar	315				-	--	-	
Total	27,214	133,013	2,202	9,043	2,214	10,220	306	1027

To analyze the system response, a contingency on k-2 is applied which is generating 1032 MW with inertia of 5595 MWs. The power is system is analyzed for four scenarios, i.e.,

- Scenario A: Governor dead band of 0.5 Hz

- Scenario B: Governor dead band of 0.5 Hz and integration of 500 MW BESS
- Scenario C: Governor dead band of 0.2 Hz
- Scenario D: Governor dead band of 0.05 Hz

The governor dead band of 0.5 Hz, 0.2 Hz and 0.05 Hz means that the primary response will be activated when frequency will change by 50±0.5 Hz or 50±0.2 Hz or 50±0.05 respectively.

The system frequency response for summer peak base case is provided in the Figure 3-1 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 3-3. For Scenario A, when the governor dead band is kept at 0.5 Hz as is the case for the most of power plants in real-time these days, the ROCOF[1] is very high, i.e., -0.078 Hz/sec and the frequency drops to 49.29 Hz and settles at 49.46 Hz. However, when BESS of 500 MW is operational, the ROCOF is -0.063 Hz/sec, frequency nadir is 49.42 Hz and the steady state frequency after activation of primary reserves is 49.54 Hz. The situation also improves for the Scenario C when all the generating units responds with the primary reserves with the dead band of 0.2 Hz. The ROCOF in that scenario is -0.065 Hz/sec, frequency nadir is 49.46 Hz and steady state frequency is 49.73 Hz. The system analyses in scenario D are as per grid code requirement when generators maintained the governor dead band of 0.05 Hz. The system operates in well secure manner as the ROCOF is -0.049 Hz/sec and the frequency nadir is 49.58 Hz and frequency settles at 49.86 Hz. The system response improves when the generating units responds faster as in the scenario when governor dead band is kept at 0.2 Hz than 0.5 Hz or with the installation of BESS.

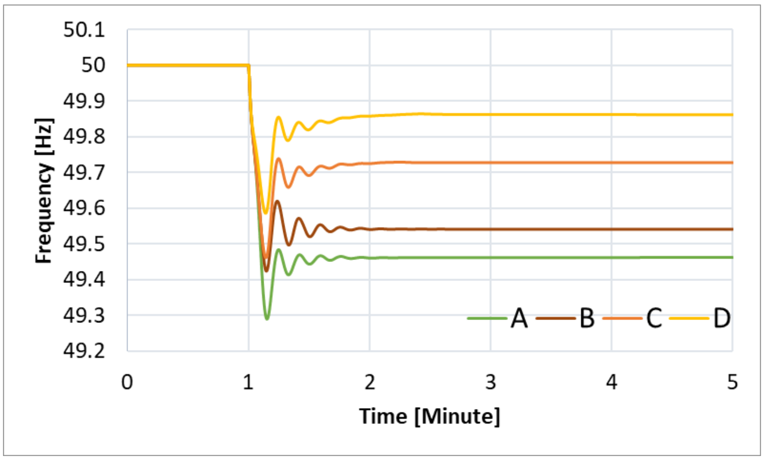

Figure 3-1: System frequency response (summer peak base case)

Table 3-3: Frequency Response after N-1 contingency (Summer peak base case)

	Scenario – A	Scenario – B	Scenario – C	Scenario – D
ROCOF [Hz/sec]	-0.078	-0.063	-0.065	-0.049
Frequency nadir [Hz]	49.29	49.42	49.46	49.58
Steady state frequency [Hz]	49.46	49.54	49.73	49.86

[1] ROCOF is calculated when frequency starts to drop after contingency till the frequency nadir. ROCOF is much high at the start but decreases when power plants start to respond.

Figure 3-2 to Figure 3-10 shows the response of the power plants operating in the NTDC system and the overall response from the KE system which is also evident as change in the KE import from NTDC. The response is provided by both the generating units and the load with load damping of 2%. The Figure 3-6 also provides the response of the BESS where 500 MW of power is provided only in 5 seconds. Dead band for the BESS is maintained at 0.2 Hz so that they do not operate frequently when load varies and the droop is set at 0.5%.

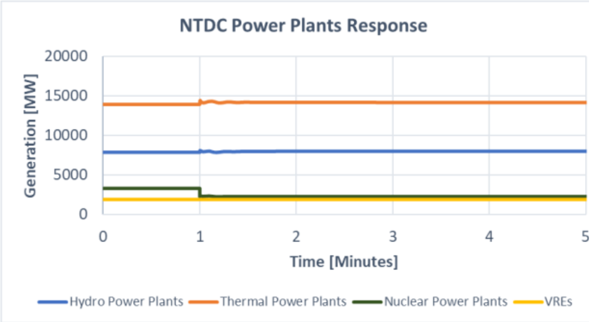

Figure 3-2: NTDC power plant response (Summer peak base case); Scenario A

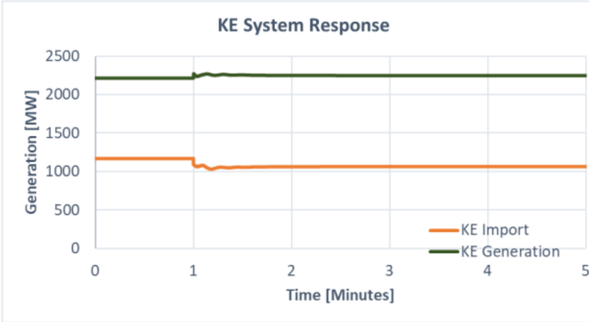

Figure 3-3: KE system response (Summer peak base case); Scenario A

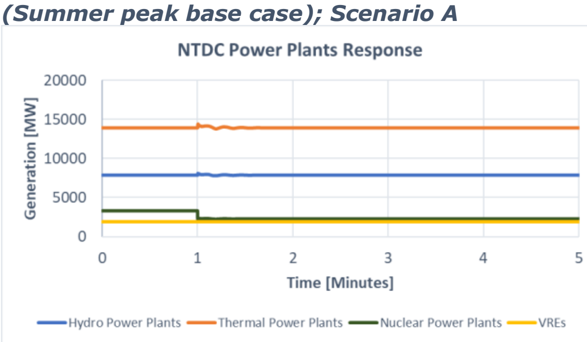

Figure 3-4: NTDC power plant response (Summer peak base case); Scenario B

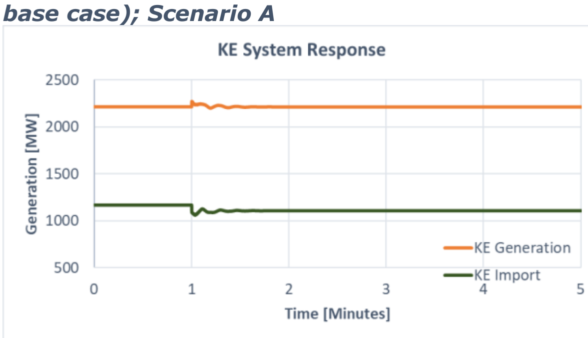

Figure 3-5: KE system response (Summer peak base case); Scenario B

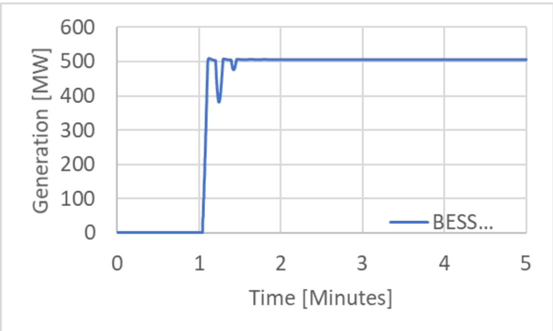

Figure 3-6: BESS response (Summer peak base case)

The comparison of the four scenarios is provided in the Table 3-4. The response shows the effective reserves that will be activated under these control settings, i.e., governor droop and dead band settings. The governor droops are maintained at 4% for all generating units except the steam turbines where 5% of the droop is applied. This table also shows the automatic load response. Load starts to responds as the frequency starts to drop on contrary to generating units where they respond only when frequency variation exceeds the dead band settings. The load shares a major portion of power imbalance in Scenario – A as the reserve activation from power plants is restricted due to high dead band. In

Scenario – B the BESS effectively provides the response along with the system load and none of the reserves are activated from the power plants as the steady state frequency is above 49.5 Hz, i.e., less than the governor dead band level. The Scenario – C shows that the available reserves can be effectively activated from the power plants with the dead band of 0.2 Hz and the response quite improves in Scenario – D with dead band of 0.05 Hz. Table also provides the response from the KE system where generating units and load responds to the power imbalance in the NTDC system. From this analysis, it is evident that fast reserves for the primary control purpose is required and the quantum have to be at least equal to the reserves activated in the Scenario – D for secure power system operation. With larger dead band the system security is at risk as the power plants do not respond even if operating less than their base load. On contrary, with dead band of 0.2 Hz and 0.05 Hz, more reserves are activated when power plants operate at the same level thereby improving the secure operation of the power system.

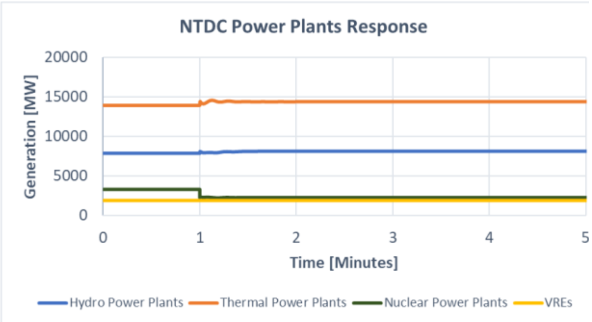

Figure 3-7: NTDC power plant response (Summer peak base case); Scenario C

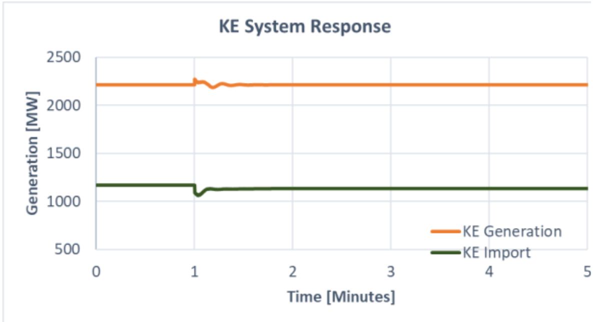

Figure 3-8: KE system response (Summer peak base case); Scenario C

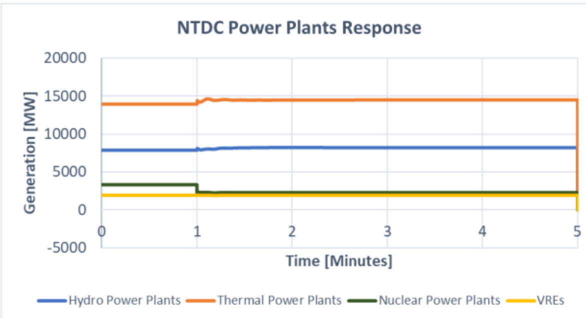

Figure 3-9: NTDC power plant response (Summer peak base case); Scenario D

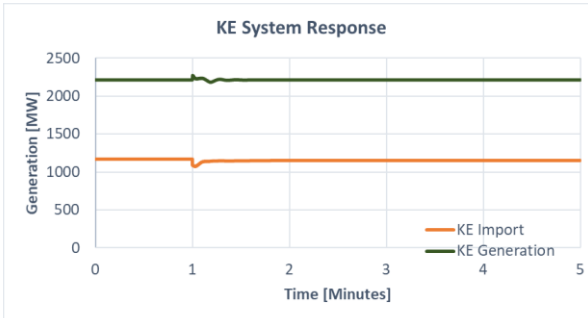

Figure 3-10: KE system response (Summer peak base case); Scenario D

Table 3-4: Comparison of Generation and load response in four Scenarios during N-1 contingencies (Summer Peak Base case)

	Scenario A		**Scenario B**		**Scenario C**		**Scenario D**	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro power plant	124		0		237		288	
Thermal power plant	242	38	0	0	476	1	582	0
Nuclear power plant	0		0		0		0	
Variable Renewable	0		0		0		0	

Energy (VREs)								
Load	557	71	473	59	282	36	144	18
BESS			500	-				
Total	923	109	973	59	995	37	1014	18

3.2 Summer Off-Peak – Base case

The summer off-peak base case is provided in Table 3-5 showing the power plants generation, power plants inertia and operating reserves which is the difference between the generated power and power plant capacity. This table shows the category of power plants while the details units online is provided in the Annexure 1. The NTDC system is generating 22,470 MW in which 1,015 MW of power is exported to KE system while KE system is generating 515 MW of generation. The inertia (in MWs) depends on the MW capacity of power plants and the frequency regulation characteristics (β) is provided in MW/Hz. In the operating conditions, the NTDC power system has inertia of 113,850 MWs and β of 8060 MW/Hz. The detailed data of each operating power plants is provided in Annexure 1. Comparing with the base case of summer peak, the system inertia is lower with fewer generating units operating in this case.

Table 3-5: Power Generation before N-1 contingency (summer off-peak base case)

	NTDC System				**KE System**			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	6,936	36,483	947	2,710	-	-	-	
Small Hydro	137	492	-	-	-	-	-	
Bagasse	100	559	-	-	-	-	-	
Nuclear	2,990	18,269	-	-	-	-	-	
Thermal	11,257	58,048	1,839	5,350	478	3294	328	343
Solar	150	-	-	-	37	-	-	-
Wind	900	-	-	-	-	-	-	-
Total	22,470	113,850	2,786	8,060	515	3294	328	343

The base case of summer off peak is evaluated with a N-1 contingency when K-2 trips. The power plant was generating 1032 MW and the system frequency is recorded the three Scenario as before:

- Scenario A: Governor dead band of 0.5 Hz
- Scenario B: Governor dead band of 0.5 Hz and integration of 500 MW BESS
- Scenario C: Governor dead band of 0.2 Hz
- Scenario D: Governor dead band of 0.05 Hz

The system frequency response for all four scenarios is provided in the Figure 3-11 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 3-6. The governor droop settings are maintained at 4% for all generating units except the steam turbine which are set at 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be -0.0922 Hz/sec and the frequency nadir and steady state frequency will be 49.207 Hz and 49.438 Hz, respectively. As the summer off peak base case has lower inertia therefore the ROCOF increases than previous case and frequency nadir and steady state frequency becomes lower.

When this base case is evaluated with a BESS of 500 MW, due to its rapid response and lower dead band, the ROCOF improves to -0.0741 Hz/sec and the frequency nadir and steady state frequency to 49.39 Hz and 49.49 Hz, respectively. The situation also improves when all the generating units responds to active power imbalances with the dead band of 0.2 Hz. The ROCOF in that case is -0.0744 Hz/sec, frequency nadir is 49.398 Hz and steady state frequency is 49.706 Hz. The system frequency response improves when the generating units responds earlier; when governor dead band is kept at 0.2 Hz instead of 0.5 Hz or with faster response from BESS system.

When the system is evaluated with the dead band of 0.05 Hz, the system operates in more secure manner. With the dead band of 0.05 Hz as required by the grid code for normal operation of the power system, the ROCOF is -0.0604 Hz/sec, Frequency nadir is 49.517 Hz and the Steady state frequency is 49.841 Hz. This will be the response of the system if primary reserves are kept on all major generating units.

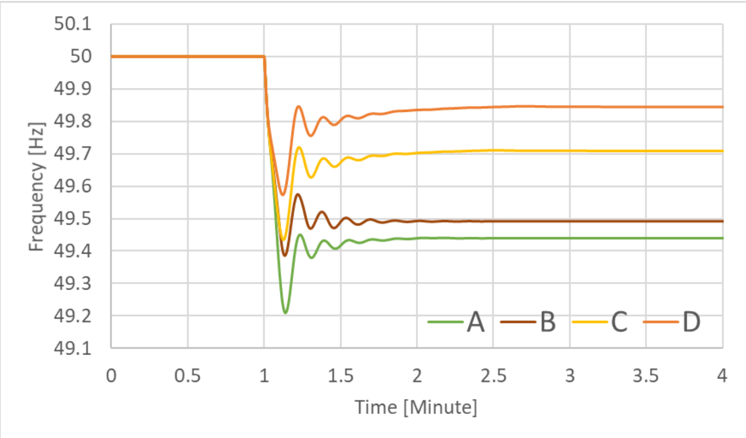

Figure 3-11 System frequency response (summer off - peak base case)

Table 3-6: Frequency Response after N-1 contingency (Summer off peak base case)

	Scenario – A	**Scenario – B**	**Scenario – C**	**Scenario – D**
ROCOF [Hz/sec]	-0.0922	-0.0741	-0.0744	-0.0604
Frequency nadir [Hz]	49.207	49.392	49.398	49.517
Steady state frequency [Hz]	49.438	49.492	49.706	49.841

For the system frequency response presented above, the response of the power plants in the NTDC system and the KE response is provided in Figure 3-12 to Figure 3-20. The KE system also responds to change in system frequency through governor droop and load response which is evident as KE import from these figures. The response of the BESS is provided in Figure 3-16 where 500 MW of power is activated in quick time. The dead band and droop settings are the same as before.

The comparison of the four scenarios is provided in the Table 3-7. The response shows the effective reserves that will be activated under these control settings, i.e., governor droop and dead band settings and the automatic load response with frequency variation. The load shares a major portion of power imbalance as in Scenario – A the reserve activation from power plants is restricted due to high dead band. In Scenario – B the BESS effectively provides the response along with the system load and less frequency reserves are activated from the power plants. The Scenario – C shows that the more reserves can be effectively activated from the power plants with the dead band of 0.2 Hz which improves more with the dead band of 0.05 Hz as power plants starts to responds earlier when frequency changes (Scenario D). Better system frequency response in Scenario – D is due to timely activation of primary reserves. It is apparent that fast reserves for the primary control purpose is required and the quantum have to be equal to the reserves activated in the scenario – D for dealing with the contingency of 1000 MW for secure power system operation.

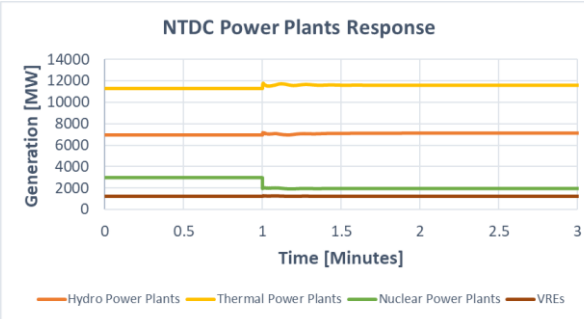

Figure 3-12: NTDC power plant response (Summer off-peak base case) Scenario A

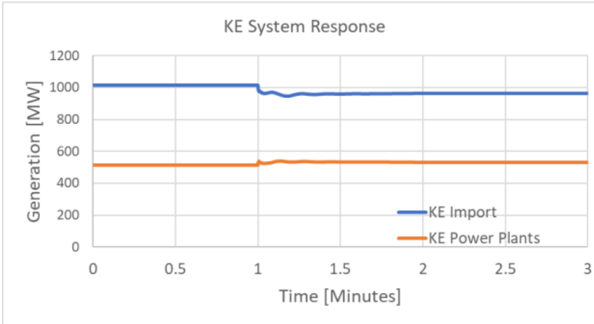

Figure 3-13: KE System response (Summer off-peak base case) Scenario A

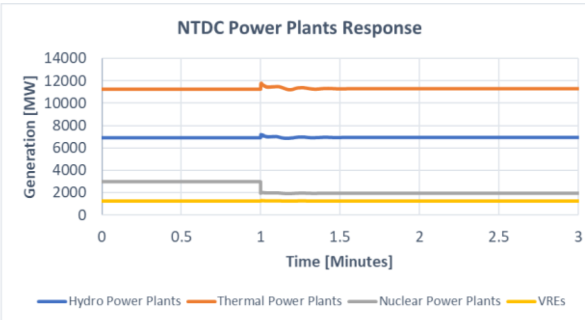

Figure 3-14: NTDC power plant response (Summer off-peak base case) Scenario B

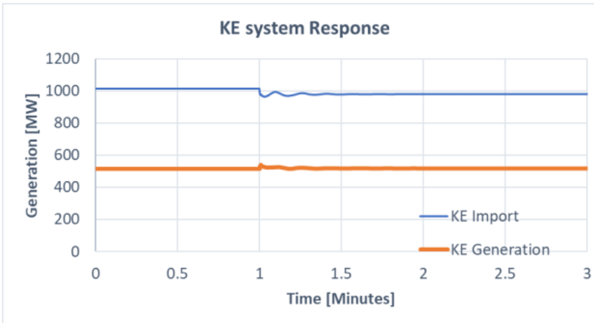

Figure 3-15: KE System response (Summer off-peak base case) Scenario B

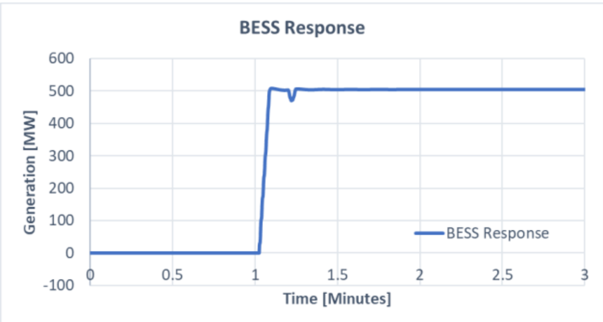

Figure 3-16: BESS response (Summer off-peak base case)

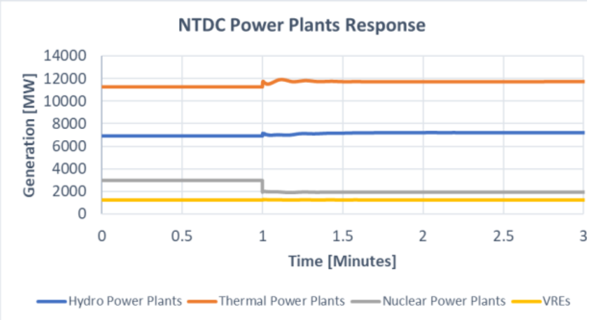

Figure 3-17: NTDC power plant response (Summer off-peak base case) Scenario C

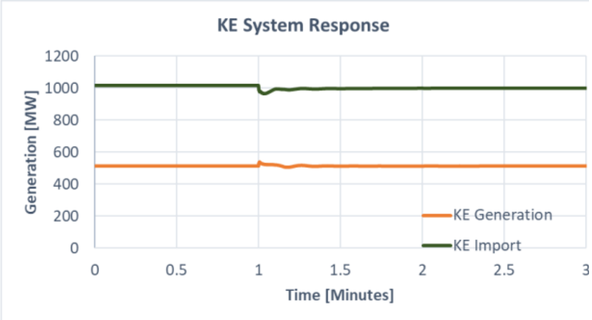

Figure 3-18: KE System response (Summer off-peak base case) Scenario C

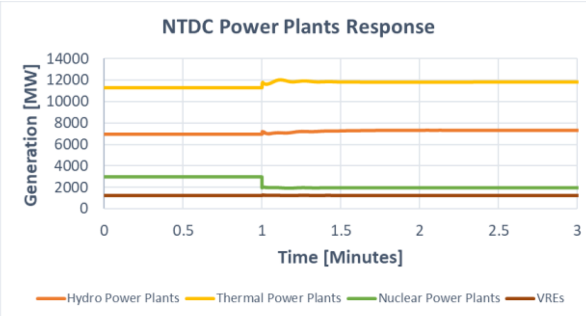

Figure 3-19: NTDC power plant response (Summer off-peak base case); Scenario D

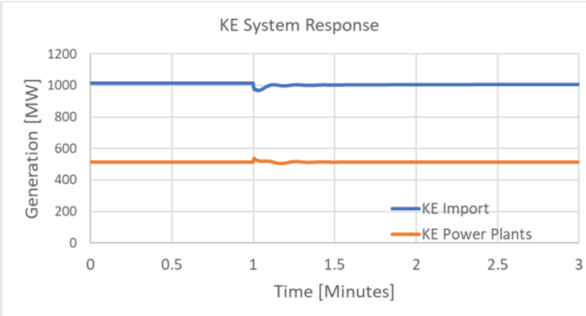

Figure 3-20: KE System response (Summer off-peak base case); Scenario D

Table 3-7: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Summer off-peak base case)

	Scenario – A		**Scenario – B**		**Scenario – C**		**Scenario – D**	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	163	-	22	-	246	-	285	-
Thermal	338	20	39	-	520	-	605	-
Nuclear	-	-	-	-	-	-	-	-
VREs	-	-	-	-	-	-	-	-
Load	479	33	434	31	248	18	133	9
BESS	-	-	500	-	-	-	-	-
Total Response	979	53	1001	31	1014	18	1023	9

3.3 Winter Peak – Base Case

Table 3-8 shows the power plants generation, inertia and reserve power capacity in the NTDC and KE system. The table is showing the category of power plants while the details units online is provided in the Annexure 1. The NTDC system is generating 15,593 MW in which 1,166 MW of power is exported to KE system while KE system is generating 1,372 MW of generation. The inertia (in MWs) depends on the MW capacity of power plants and frequency regulation characteristics (β) is provided in MW/Hz depending on the reserve availability and droop settings. In the operating conditions, the NTDC power system has inertia of 75,057 MWs and β of 6298 MW/Hz. The detailed data of each operating power plants is provided in Annexure 1.

Table 3-8: Power Generation before N-1 contingency (winter peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	1,564	8,613	292	843	-	-	-	
Small Hydro	94	185			-	-	-	
Bagasse	93	407			-	-	-	
Nuclear	3,305	20,108						
Thermal	10,105	45,744	1,017	5455	1,372	6,313	181	653
Wind	432				-	-	-	
Solar	0				-	-	-	
Total	15,593	75,057	1,309	6298	1,372	6,313	181	653

This base case of again evaluated with a N-1 contingency when K-2 trips resulting in an imbalance of 1032 MW in real time. The power system is than evaluated under three cases i.e.:

- Scenario A: Governor dead band of 0.5 Hz
- Scenario B: Governor dead band of 0.5 Hz and integration of 500 MW BESS
- Scenario C: Governor dead band of 0.2 Hz
- Scenario D: Governor dead band of 0.05 Hz

The system frequency response for all four scenarios is provided in the Figure 3-21 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 3-9. As earlier, governor droop settings are maintained at 4% for all generating units except the steam turbine which are set at 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be-0.133 Hz/sec and the frequency nadir and steady state frequency will be 49.02 Hz and 49.37 Hz, respectively. There is substantial reduction in system frequency as the system inertia has reduced due to less power demand. The reduction in system inertia results in high ROCOF and with less generating unit online the frequency nadir and steady state frequency is also reduced.

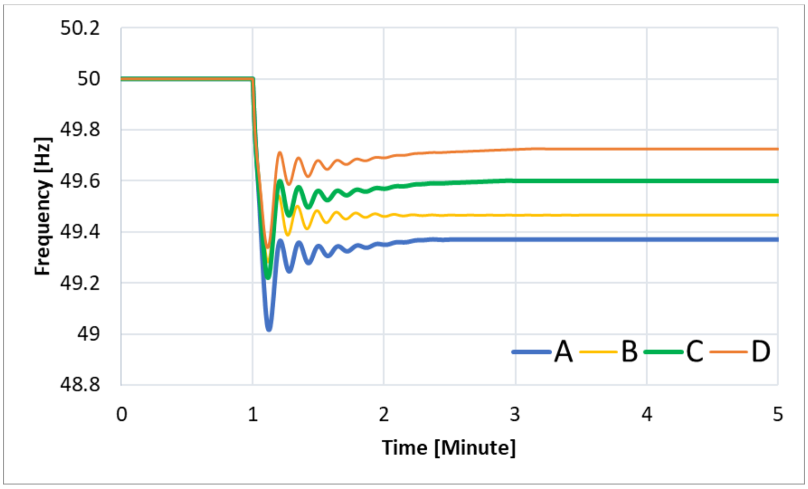

Figure 3-21: System frequency response (winter peak base case)

Table 3-9: Frequency Response after N-1 contingency (Winter peak base case)

	Scenario – A	Scenario – B	Scenario – C	Scenario – D
ROCOF [Hz/sec]	-0.133	-0.104	-0.113	-0.099
Frequency nadir [Hz]	49.02	49.28	49.22	49.34
Steady state frequency [Hz]	49.37	49.47	49.60	49.73

When this base case is evaluated with a BESS of 500 MW, the power system will have ROCOF of -0.104 Hz/sec and the frequency nadir and steady state frequency to 49.28 Hz and 49.47 Hz, respectively. The quick response from the BESS improves the system performance. When generating units operate with a dead band of 0.2 Hz, the ROCOF is -0.113 Hz/sec, frequency nadir is 49.22 Hz and steady state frequency is 49.60 Hz. While with the dead band of 0.05 Hz, ROCOF in that scenario is -0.099 Hz/sec, frequency nadir is 49.34 Hz and steady state frequency is 49.73 Hz.

For the system frequency response presented above, Figure 3-22 to Figure 3-30 shows the response of the power plants in the NTDC system and the KE response through governor action and load damping. The response of the BESS is provided in Figure 3-26 where 500 MW of power is activated in quick time. The dead band and droop settings are the same as the previous cases.

Table 3-10 provides the comparison of the four scenarios showing the effective reserves that will be activated under aforementioned governor droop and dead band settings. Comparing the load damping with previous cases the response is lower for the same contingency, and this is due to the reduction in load demand. The less load response and lower inertia also causes more frequency variation. Also, in Scenario – A the reserve activation from power plants is restricted due to high dead band comparing it with the Scenario C and Scenario D. The Scenario – B shows the effectiveness of BESS that provides quick response thereby minimizing the response from the system load and reserve burden on power plants as in Scenario – A. The dead band of 0.2 Hz and 0.05 Hz stabilizes the power system with more effective power reserves activation from the Thermal power plants. Better system frequency response in Scenario – B or Scenario – D is due to the timely activation of fast frequency reserves. It is apparent that fast reserves for the primary control purpose is required and the quantum have to be equal to the reserve power activated in the Scenario – D presented here to maintain system frequency within limits for operational security.

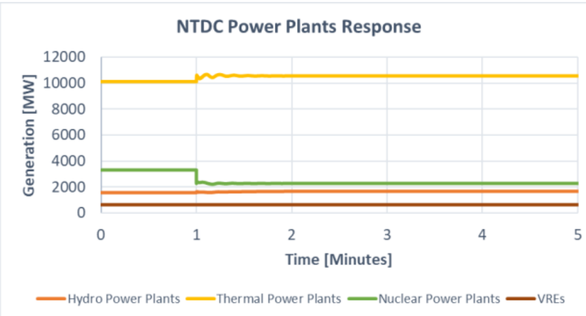

Figure 3-22: NTDC power plant response (Winter peak base case) Scenario A

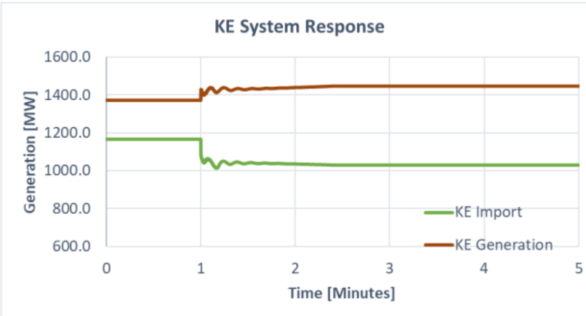

Figure 3-23: KE System response (Winter peak base case) Scenario A

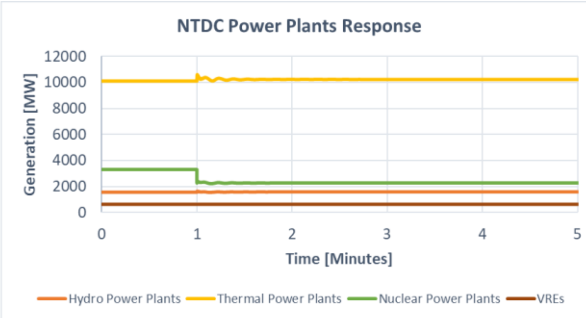

Figure 3-24: NTDC power plant response (Winter peak base case) Scenario B

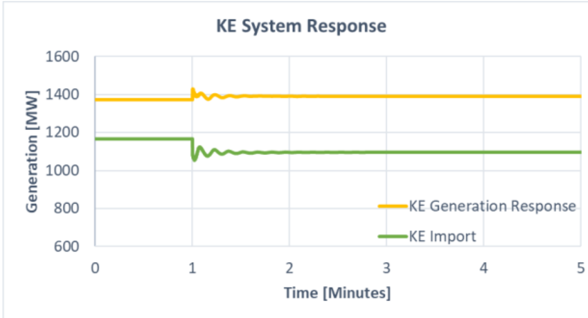

Figure 3-25: KE System response (Winter peak base case) Scenario B

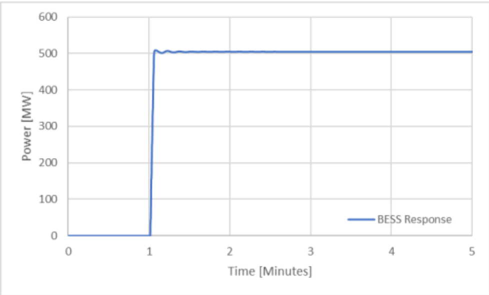

Figure 3-26: BESS response (Winter peak base case)

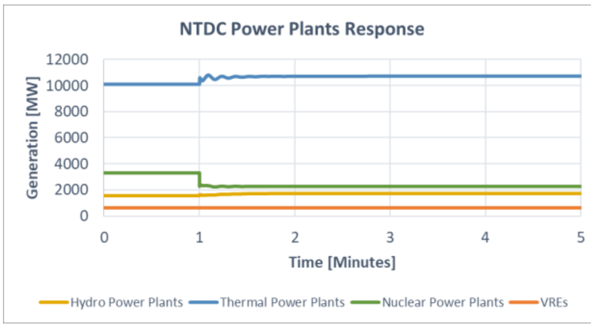

Figure 3-27: NTDC power plant response (Winter peak base case) Scenario C

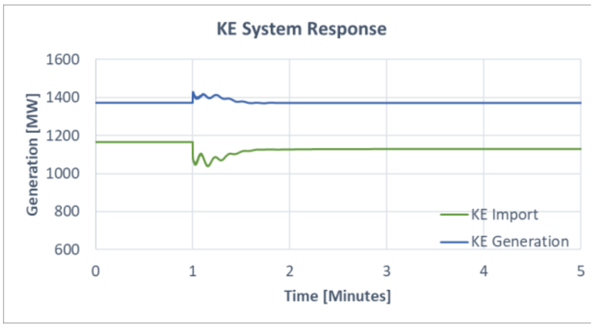

Figure 3-28: KE System response (Winter peak base case) Scenario C

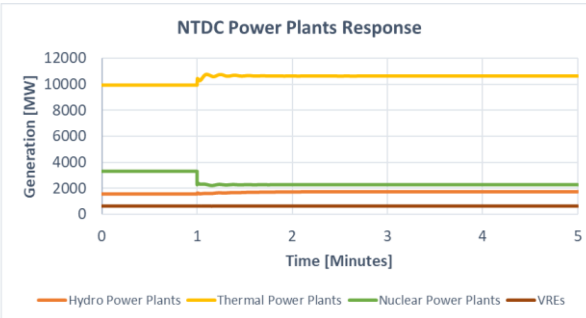

Figure 3-29: NTDC power plant response (Winter peak base case) Scenario D

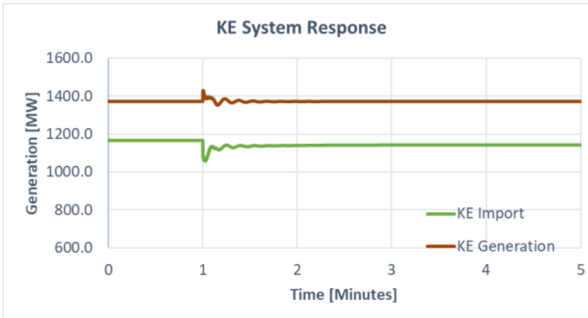

Figure 3-30: KE System response (Winter peak base case) Scenario D

Table 3-10: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Winter peak base case)

	Scenario A		**Scenario B**		**Scenario C**		**Scenario D**	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	91		25		140	-	158	

Thermal	433	85	124	23	623	-	689	0
Nuclear	0		0		-	-	0	
VREs	0		0		-	-	0	
Load	360	63	307	53	230	39	158	27
BESS			500	-	-	-		
Total Response	884	148	956	76	993	39	1005	27

3.4 Winter Off-Peak – Base Case

The winter off-peak base case is presented in Table 3-11 showing the power plants generation, inertia in MWs and power reserves, difference between the generated power and power plant capacity. The table shows the category of power plants while the details units online is provided in the Annexure 1. The NTDC system is generating 8,268 MW in which 566 MW of power is exported to KE system while KE system is generating 406 MW of generation. The inertia (in MWs), i.e., 52,826 MWs and frequency regulation characteristics (β) is provided in MW/Hz depending on the reserve availability and droop settings. In the operating conditions, β is 4152 MW/Hz. The detailed data of each operating power plants is provided in Annexure 1.

Table 3-11: Power Generation before N-1 contingency (winter off- peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	486	3,199	200	285	-	-	-	
Small Hydro	68	150			-	-	-	
Bagasse	100	375			-	-	-	
Nuclear	2,490	20,360						
Thermal	4,946	28,742	1,584	3867	406	3,178	356	360
Wind	178				-	-	-	
Solar	0				-	-	-	
Total	8,268	52,826	1,784	4152	406	3,178	356	360

The base case of winter off peak is evaluated with a N-1 contingency when K-2 trips resulting in an imbalance of 745 MW. The system response is evaluated again for the three cases:

- Scenario A: Governor dead band of 0.5 Hz
- Scenario B: Governor dead band of 0.5 Hz and integration of 500 MW BESS
- Scenario C: Governor dead band of 0.2 Hz
- Scenario D: Governor dead band of 0.05 Hz

The system frequency response for all the four scenarios is provided in the Figure 3-31 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 3-12. As before, governor droop settings are maintained at 4% for all generating units except the steam turbine which are set at 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be -0.126 Hz/sec and the frequency nadir and steady state frequency will be 49.04 Hz and 49.38 Hz, respectively. The inertia is lowest in the off-peak winter Scenario but the impact is almost similar as the winter peak scenarios as the contingency on K-2 resulted in an imbalance of 745 MW compared to the previous cases when 1032 MW of imbalance was produced.

When this base case is evaluated with an integration of 500 MW BESS, the ROCOF improves to -0.077 Hz/sec and the frequency nadir and steady state frequency to 49.41 Hz and 49.48 Hz, respectively. The BESS stabilizes the system effectively and is more useful in scenario of low inertia. The case when evaluated for governor dead band of 0.2 Hz and 0.05 Hz is also effective but not as with integration of BESS. With governor dead band of 0.2 Hz, the system ROCOF is -0.103 Hz/sec, frequency nadir is 49.29 Hz and steady state frequency is 49.64 Hz. While with governor dead band of 0.05 Hz, the system ROCOF is -0.087 Hz/sec, frequency nadir is 49.42 Hz and steady state frequency is 49.78 Hz.

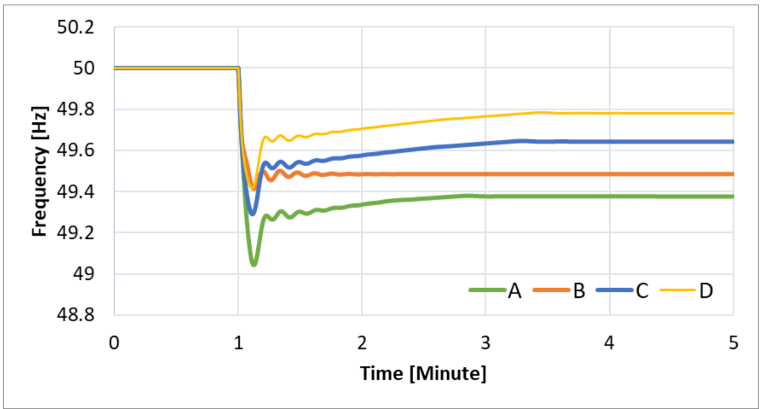

Figure 3-31: System frequency response (winter off peak base case)

Table 3-12: Frequency Response after N-1 contingency (Winter off- peak base case)

	Scenario – A	Scenario – B	Scenario – C	Scenario – D
ROCOF [Hz/sec]	-0.126	-0.077	-0.103	-0.087
Frequency nadir [Hz]	49.04	49.41	49.29	49.42
Steady state frequency [Hz]	49.38	49.48	49.64	49.78

For the system frequency response presented above, the response of the power plants in the NTDC system and the KE response is provided in Figure 3-32 to Figure 3-40. The response of the BESS is provided in Figure 3-36 where 500 MW of power is activated in quick time. The dead band and droop settings are the same for BESS. i.e., dead band of 0.2 Hz and droop settings of 0.5%.

The four scenarios for winter off-peak are compared in the Table 3-13. The response shows the effective reserves that will be activated under these control settings, i.e., governor droop and dead band settings and the automatic load response with frequency variation. The load damping response has reduced due to lower load demand and with the high dead band and low generation capacity the frequency variation is high. The system response will be worse if K-2 was generating 1032 MW as the earlier cases. Generating units responds effectively with the dead band of 0.05 Hz but the ROCOF and frequency nadir can be minimized with BESS system effectively due to low system inertia.

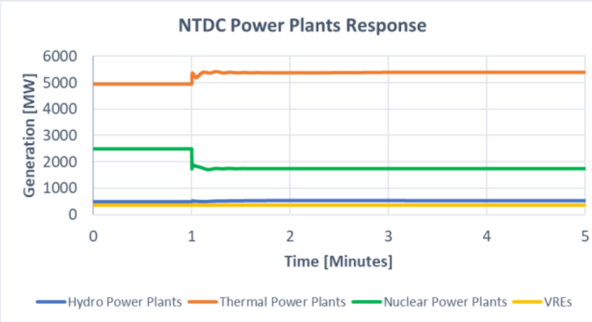

Figure 3-32: NTDC power plant response (Winter off-peak base case) Scenario A

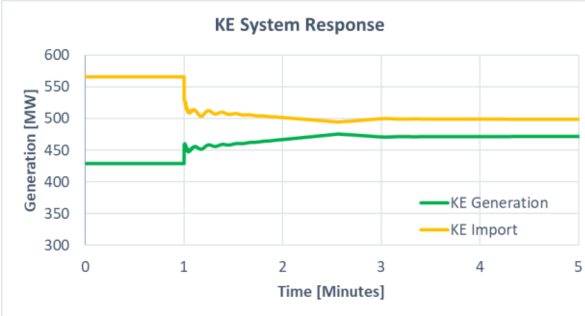

Figure 3-33: KE System response (Winter off-peak base case) Scenario A

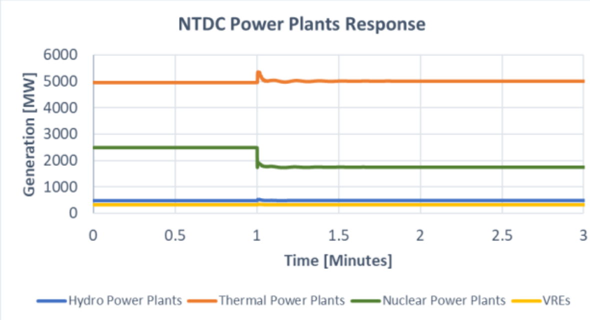

Figure 3-34: NTDC power plant response (Winter off-peak base case) Scenario B

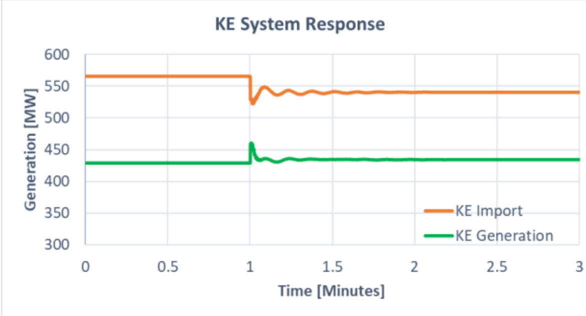

Figure 3-35: KE System response (Winter off-peak base case) Scenario B

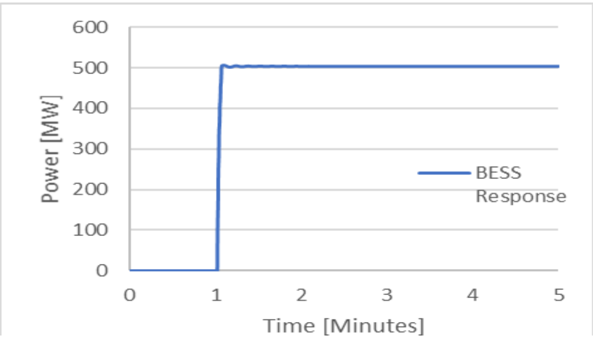

Figure 3-36: BESS Response (Winter off-peak base case)

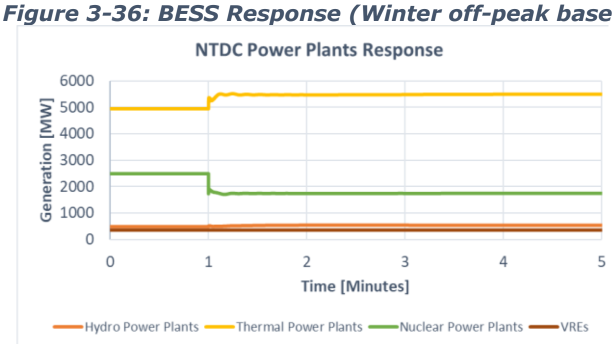

Figure 3-37: NTDC power plant response (Winter off-peak base case) Scenario C

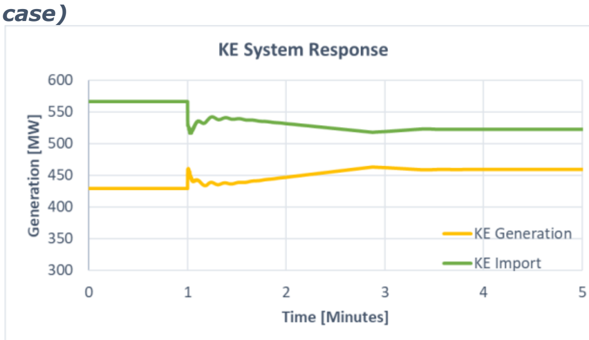

Figure 3-38: KE System response (Winter off-peak base case) Scenario C

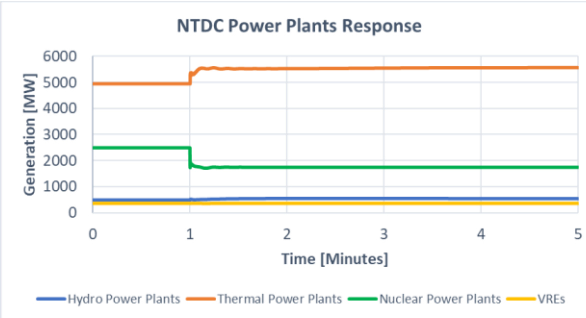

Figure 3-39: NTDC power plant response (Winter off-peak base case) Scenario D

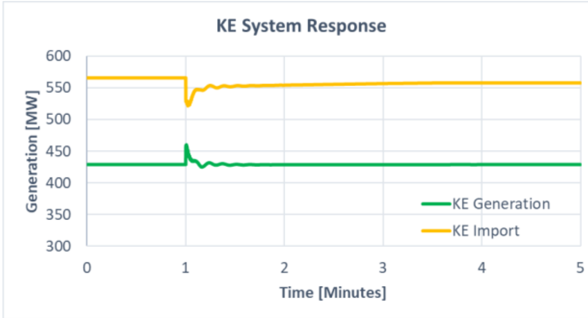

Figure 3-40: KE System response (Winter off-peak base case) Scenario D

Table 3-13: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Winter off-peak base case)

	Scenario A		Scenario B		Scenario C		Scenario D	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	36		5		45		51	
Thermal	450	44	54	7	576	0	623	0
Nuclear	0		0		0		0	
VREs	0		0		0		0	
Load	191	24	158	21	109	14	63	8
BESS			500	-				
Total Response	677	68	717	28	731	14	737	8

3.5 Section Recommendations

The section provides an overview of the National power system during different operating conditions of the summers and winters. The study evaluated each base case for four scenarios, i.e., when generating unit are operating with dead band of 0.5 Hz which is the real-time case for most of the power plants, when BESS of 500 MW is integrated and when generating units are operating with dead band of 0.2 Hz and with 0.05 Hz. It is observed that power system will have sufficient inertia to deal with contingency during summer but in winter the low inertia minimized the system security. For secure power system operations, BESS system will provide quick response and reduces the ROCOF and frequency Nadir. BESS system also minimizes the reserve burden and hence more generating units can operate on the base load as per the merit order.

The availability of operating reserves for primary frequency control is only effective if the dead band is kept at 0.05 Hz or at least 0.2 Hz with high frequency regulating characteristics β. For any power imbalance, the steady state frequency will be:

$$\Delta f = \frac{\Delta P}{\beta_g + \beta_l}$$

where

Δf is the steady state frequency;

ΔP is the active power imbalance;

β_l is the load damping; and

β_g is the sum of frequency regulation from all generating units.

$$\beta_g = \sum_{i=1}^{n} \beta_{g,i}$$
$$and\ \beta_{g,i} = \frac{P_i}{R_i \cdot f_n}$$

where

P_i is the rated power of generating unit i

R_i is the governor droop of generating unit i

f_n is the nominal frequency

In the above equation only, those units are counted that have active reserve power. Keeping reserves on some of the generating units will reduce the value of β_g thus affects secure operation. β_g for any generating units is considered if they able to response for frequency change.

Considering the summer off peak base case where more reserve is activated, Primary reserves of ±890 MW are required for secure power system operation to deal with the contingency event of 1032 MW. NTDC and KE system have to participate in providing the required primary reserves. Average annual load demand of KE with respect to the total system load is 11% and average generation is 5.8 %. Based on these, KE shall contribute 10% of the total primary reserves, i.e., 89 MW and NTDC shall contribute 90% of the required primary reserves, i.e., 801 MW. The reserve power of 801 MW needs to be placed on generating units that can response with regulation characteristics of 6133 MW/Hz to limit the steady state frequency error of 0.2 Hz.

It is recommended that all generating unit counted in frequency regulation (β_g) have to be dispatched at least 7-8% less than their base load, thereby have provision of providing primary frequency response. Gas turbine generating units if dispatched at 100% is unable to keep its output constant when frequency drops. This has been noted in an event on May 03, 2023 at 14:34:20, the details of which are provided in Annexure 2. NPCC has started to host meeting with thermal power plants to acquire their view point on activation of Frequency response at respective plants. The meetings minutes is provided in Annexure 2 showing their concern on provision of primary responses. It has also been pointed out by the power plant operators that maintaining reserves on some of the plants will impact the power plant health and they may not activate their speed governors in that case.

It is important to mention here that power plants are capable of providing primary response as per grid code requirement and with different droop settings. According to PPA 8.3 power plants carry Turbine Governor Operation tests that shows their capability of providing primary reserves. The reports for some of the power plants are attached in Annexure 2 that details their capability of providing primary response.

4 Primary Reserves Requirement for Cases with increased integration of Variable Renewable Energy (VRE) during N-1 contingency

This part of the study analyses the power system frequency response with integration of 2500 MW of Solar PV and 1000 MW of wind power. It is important to mention here that base load of the NTDC system and KE system remains the same and for the integration of wind and solar power, thermal power plants generation is adjusted accordingly. The details for summer peak, summer off-peak, winter peak and winter off peak is provided in Table 4-1.

Table 4-1: NTDC and KE system load demand and generation with VRE integration

Sr. No.	Cases	NTDC load demand [MW]	NTDC Generation [MW]	KE load demand [MW]	KE Generation [MW]	KE Import [MW]
1	Summer Peak	26,045	27,214	3,383	2,214	1,169
2	Summer off-peak	21,455	22,470	1,530	515	1,015
3	Winter Peak	14,427	15,593	2,536	1,370	1,166
4	Winter off-peak	7,874	8,440	996	430	566

Again, the power system for the above cases will analyzed during N – 1 contingency, i.e., tripping of largest generating units (K-2) and will provide an analysis on the rate of change of frequency (ROCOF), frequency nadir and steady state frequency during different operating conditions. Based on these analyses the primary reserves (fast frequency reserves) will be suggested for secure operation of power system.

4.1 Summer Peak with VRE integration

For summer peak, Table 4-2 mentions the power generation, system inertia and reserves power for the power plants, operating within the NTDC and KE system. The operating reserves are the difference of the power generated from their online capacities. The NTDC system as earlier case is generating 27,214 MW in which 1,169 MW of power is exported to KE system while KE system is generating 2,214 MW of generation. The inertia of NTCD power system is 125,955 MWs and frequency regulation characteristics (β) is 7628 MW/Hz depending on the reserve availability and droop settings. Comparing the Table 4-2 with Table 3-2, the VREs have replaced the power generation from thermal power plants thereby impacting the total system inertia and β. The details of power plants operating under each category is provided in Annexure 3.

Table 4-2: Power Generation before N-1 contingency (summer peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	8,170	40,845	535	2,391	-	-	-	
Small Hydro	150	512			-	-	-	
Bagasse	100	559			-	-	-	
Nuclear	3,305	20,360			57	531	-	
Thermal	11,522	63,679	2,341	5,237	2,038	9,689	306	1027
Wind	2,052				119	-	-	
Solar	1,915				-	-	-	
Total	27,214	125,955	2,876	7,628	2,214	10,220	306	1027

To analyze the system response under the above operating conditions a contingency on k-2 generating 1032 MW is applied. The power is system is again analyzed the following cases:

- Scenario A: Governor dead band of 0.5 Hz
- Scenario B: Governor dead band of 0.5 Hz and integration of 500 MW BESS
- Scenario C: Governor dead band of 0.2 Hz
- Scenario D: Governor dead band of 0.05 Hz

The governor dead band of 0.5 Hz, 0.2 and 0.05 Hz means that generating units do not provide primary response when frequency change is within 50±0.5 Hz or 50±0.2 Hz or 50±0.05 Hz respectively.

The system frequency response for summer peak base case is provided in the Figure 4-1 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 4-3. For Scenario A, when governor dead band is kept at 0.5 Hz, the ROCOF is -0.079 Hz/sec, frequency nadir is 49.29 Hz and steady state frequency is 49.46 Hz. However, with BESS of 500 MW, the ROCOF is -0.066 Hz/sec, frequency nadir is 49.43 Hz and the steady state frequency after activation of primary reserves is 49.54 Hz. The situation also improves for the Scenario C when all the generating units responds with the dead band of 0.2 Hz. The ROCOF in that case is -0.064 Hz/sec, frequency nadir is 49.46 Hz and steady state frequency is 49.72 Hz. In scenario D when the governor dead band is kept at 0.05 Hz, as per the grid code requirement, the system operates in well secure manner. ROCOF in that scenario is -0.05 Hz/sec, frequency nadir is 49.58 Hz and frequency settles at 49.86 Hz. Comparing the case with the one presented in Section 3.1, the VRE integration have not much impact on system frequency due to the high system inertia during the summer season. With BESS, the system response is same as in section 3.1.

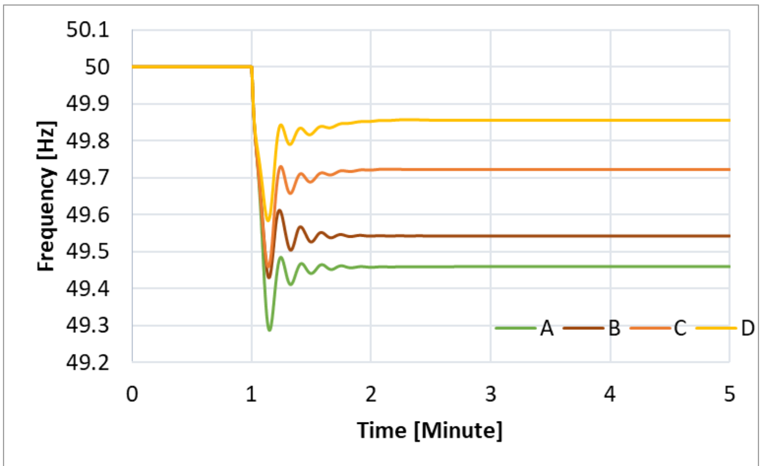

Figure 4-1: System frequency response (summer peak base case)

Table 4-3: Frequency Response after N-1 contingency (Summer peak base case)

	Case – A	Case – B	Case – C	Case – D
ROCOF [Hz/sec]	-0.079	-0.066	-0.064	-0.050

Frequency nadir [Hz]	49.29	49.43	49.46	49.58
Steady state frequency [Hz]	49.46	49.54	49.72	49.86

Figure 4-2 to Figure 4-10 shows the response of the power plants operating in the NTDC system and the overall response from the KE. The response is provided by the generating units and the load units with a load damping of 2%. Figure 4-6 shows the response of the BESS where 500 MW of power is activated with droop of 0.5% after frequency variation exceed the dead band of 0.2 Hz. The four scenarios are compared in the Table 4-4 and it can be observed that more reserves from power plants are activated in Scenario D than Scenario A and thereby providing better system frequency response. Also, to mention here governor droop settings are also kept the same as before, i.e., 4% for all generating units except the steam turbines where 5% of the droop is applied. Comparing the Table 4-4 with Table 3-4, hydro power plants are activating more reserves and this is due less response from thermal generation with reduced capacity. Contribution from the load damping and KE system is important for system security but that need to minimized with fast frequency reserves which is minimize frequency variation and will enhance system security.

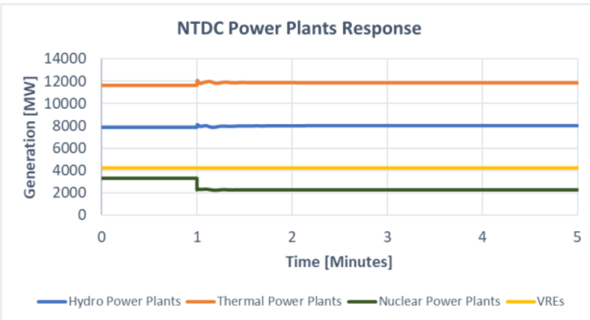

Figure 4-2: NTDC power plant response (Summer peak base case) Case – A

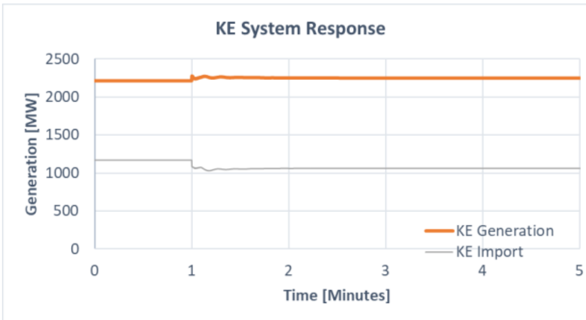

Figure 4-3: KE system response (Summer peak base case) Scenario A

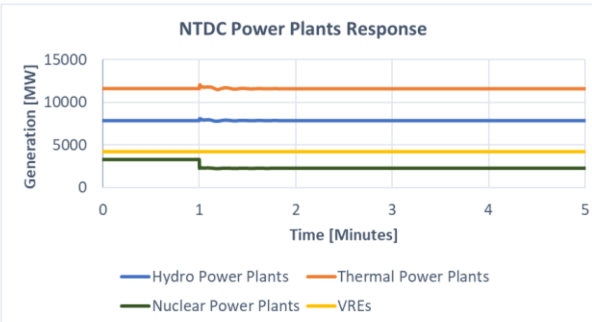

Figure 4-4: NTDC power plant response (Summer peak base case) Case -B

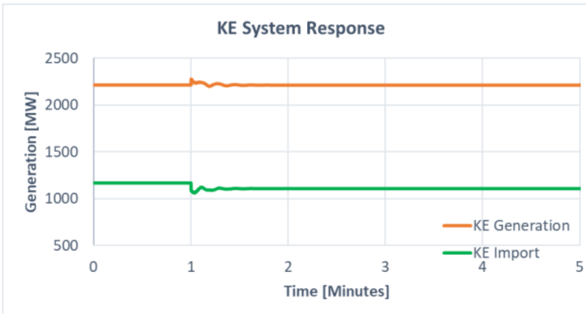

Figure 4-5: KE system response (Summer peak base case) Scenario B

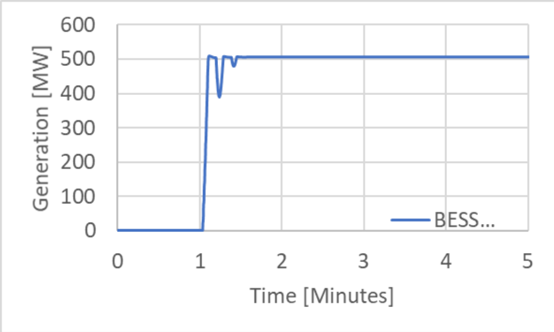

Figure 4-6: BESS response (Summer peak base case)

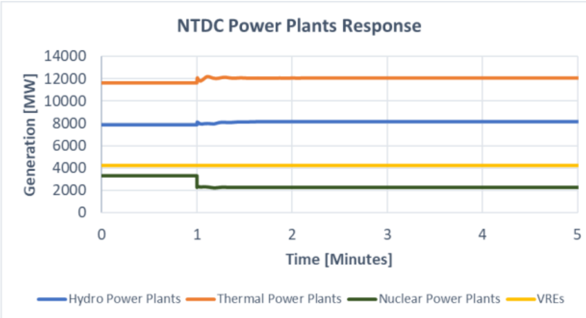

Figure 4-7: NTDC power plant response (Summer peak base case) – Case -C

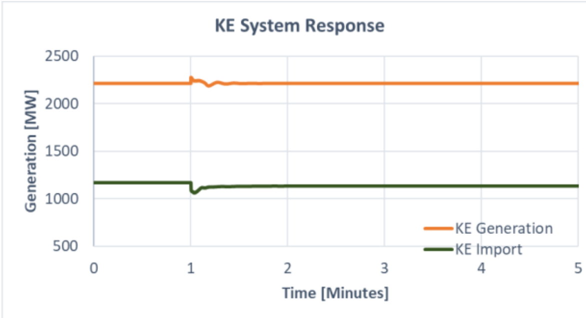

Figure 4-8: KE system response (Summer peak base case) Scenario C

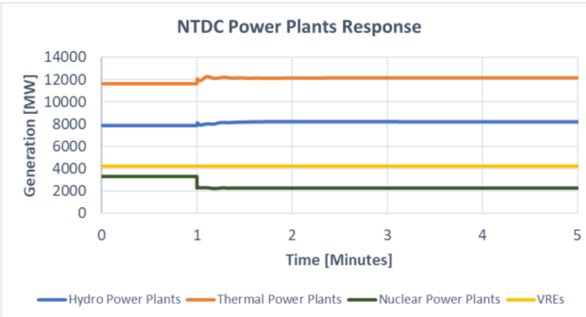

Figure 4-9: NTDC power plant response (Summer peak base case) – Case -D

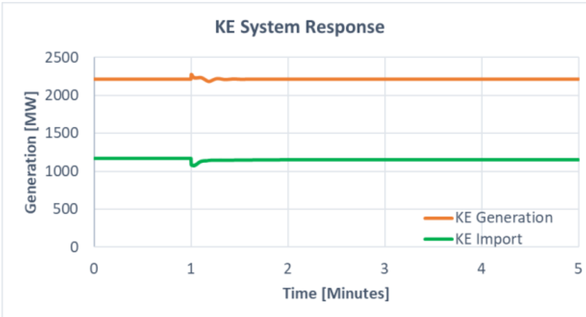

Figure 4-10: KE system response (Summer peak base case) Scenario D

Table 4-4: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Summer Peak Base case)

	Case – A		Case – B		Case – C		Case – D	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro power plant	132	-	-	-	254	-	309	-
Thermal power plant	229	40	-	-	453	1	554	-
Nuclear power plant	-	-	-	-	-	-	-	-
VREs	-	-	-	-	-	-	-	-
Load	569	72	470	62	288	36	149	20
BESS	-	-	500	-	-	-	-	-
Total	920	112	970	62	995	37	1012	20

4.2 Summer Off-Peak with VRE Integration

Table 4-5 shows the power plants generation, power plants inertia and operating reserves for the summer off peak case. The reserves shown here is the difference between the generated power and power plant capacity. The values provided in the table are aggregated in category wise while the details of generating units are provided in the Annexure 3. The NTDC system is generating 22,470 MW in which 1,015 MW of power is exported to KE system while KE system is generating 515 MW of generation. The inertia is provided in MWs that depends on the MW capacity of power plants. The inertia of NTCD power system is 111,887 MWs and frequency regulation characteristics (β) is 7,738 MW/Hz depending on the reserve availability and droop settings. Comparing with the base case of summer off-peak (Section 3.2), the system inertia and β is lower as generation from the thermal units are replaced by VREs.

Table 4-5: Power Generation before N-1 contingency (summer off-peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	6,936	36,483	947	2,710	-	-	-	
Small Hydro	137	492	-		-	-	-	
Bagasse	100	559	-		-	-	-	
Nuclear	2,990	18,269	-		-	-	-	
Thermal	9,771	56,085	2,547	5,028	478	3294	328	340
Wind	1,386		-		-	-	-	-
Solar	1,150		-		37	-	-	-
Total	22,470	111,887	3,494	7,738	515	3294	328	340

The base case of summer off peak is evaluated with a N-1 contingency when K-2 trips taking 1032 MW out from generation. The system frequency is recorded for the four scenarios:

- Scenario A: Governor dead band is kept at 0.5 Hz
- Scenario B: Governor dead band at 0.5 Hz and BESS of 500 MW is operating
- Scenario C: Governor dead band is kept at 0.2 Hz
- Scenario D: Governor dead band is kept at 0.05 Hz

The system frequency response for all three cases is provided in the Figure 4-11 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 4-6. The governor droop setting is maintained at 4% for all generating units except the steam turbine which is 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be -0.0922 Hz/sec and the frequency nadir and steady state frequency will be 49.207 Hz and 49.437 Hz, respectively. Compared to the summer off peak base case, decrease in system inertia impacted the ROCOF and frequency response.

With integration of BESS of 500 MW, the ROCOF improves to -0.0741 Hz/sec and the frequency nadir and steady state frequency to 49.392 Hz and 49.4918 Hz, respectively.

This is due to the rapid response of the BESS. The situation also improves when all the generating units of NTDC responds with the primary reserves when dead band of 0.2 Hz or 0.05 Hz is activated. With governor dead band of 0.2 Hz, the ROCOF is -0.0744 Hz/sec, frequency nadir is 49.398 Hz and steady state frequency is 49.7057 Hz while with governor dead band of 0.05 Hz, the ROCOF is -0.0604 Hz/sec, frequency nadir is 49.517 Hz and steady state frequency is 49.8408 Hz. Compared with the Table 3-6, the response almost remains the same for all the scenarios as the system has enough inertia and most of the online generating units responds to the power imbalance.

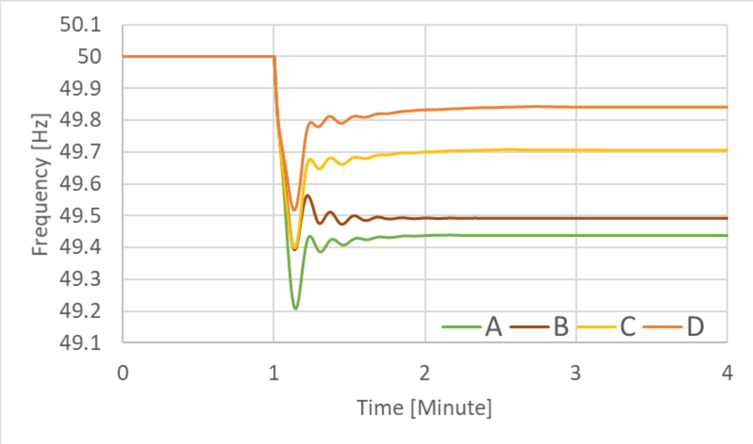

Figure 4-11 System frequency response (summer off - peak base case)

Table 4-6: Frequency Response after N-1 contingency (Summer off peak base case)

	Scenario – A	**Scenario – B**	**Scenario – C**	**Scenario – D**
ROCOF [Hz/sec]	-0.0922	-0.0741	-0.0744	-0.0604
Frequency nadir [Hz]	49.207	49.392	49.398	49.517
Steady state frequency [Hz]	49.4378	49.4918	49.7057	49.8408

The response of the power plants in the NTDC system and the KE system is provided in Figure 4-12 to Figure 4-20. The KE system responds to change in system frequency through governor droop and load damping, observed as KE import. The response of the BESS is provided in Figure 4-16 where 500 MW of power is activated when dead band of 0.2 Hz and droop settings of 0.5% is maintained. The four scenarios are compared in Table 4-7 where the effective reserves activation under each scenario is provided for the control settings of governor droop and dead band and load damping. The load shares a major portion of power imbalance in scenario – A as the reserve activation from power plants is restricted due to high dead band. In scenario – B the BESS effectively provides the response along with the system load with minimum response from power plants. The scenario – C and scenario – D shows that the available reserves can be effectively activated from the power plants with the dead band of 0.2 Hz and 0.05 Hz as power plants starts to responds earlier and thereby system can operate more securely.

Comparing the Table 4-7 with Table 3-7, less reserve is activated from thermal power plants and the burden is shared by increasing the reserve power activation from the hydro power plants. Improved system frequency response in scenario – B, C or D is due to the timely activation of fast frequency. It is apparent that fast reserves for the primary control purpose is required and the quantum equal to the reserves activated in scenario – D maintains system frequency within limits thereby improving system security.

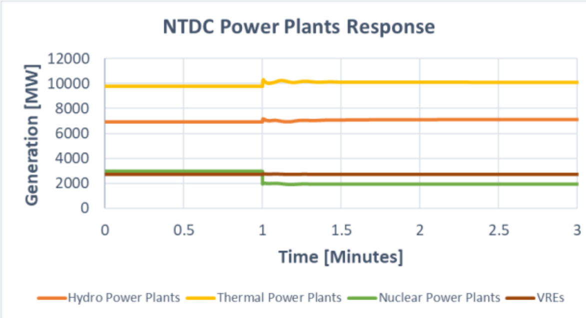

Figure 4-12: NTDC power plant response (Summer off-peak base case) Scenario A

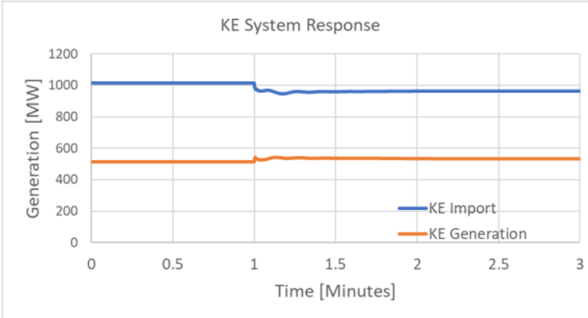

Figure 4-13: KE System response (Summer off-peak base case) Scenario A

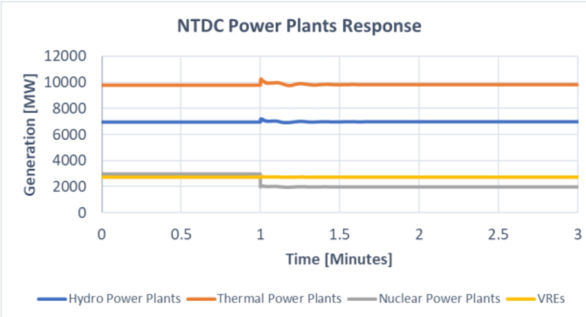

Figure 4-14: NTDC power plant response (Summer off-peak base case) Scenario B

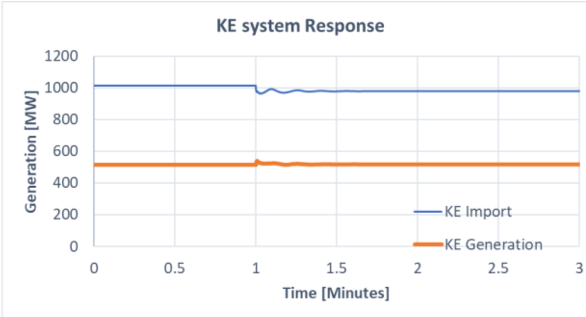

Figure 4-15: KE System response (Summer off-peak base case) Scenario B

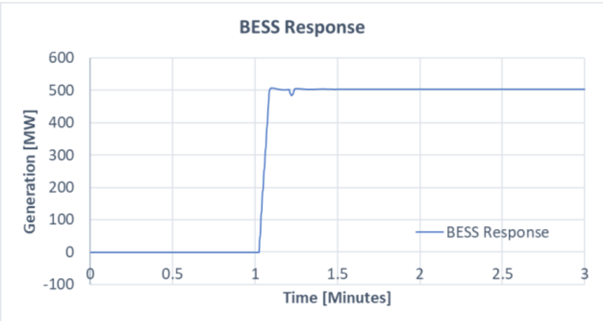

Figure 4-16: BESS response (Summer off-peak base case)

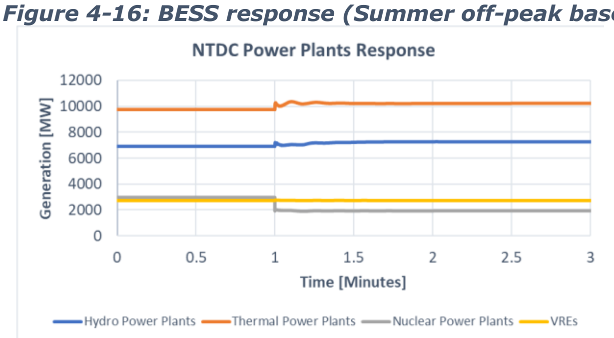

Figure 4-17: NTDC power plant response (Summer off-peak base case) Scenario C

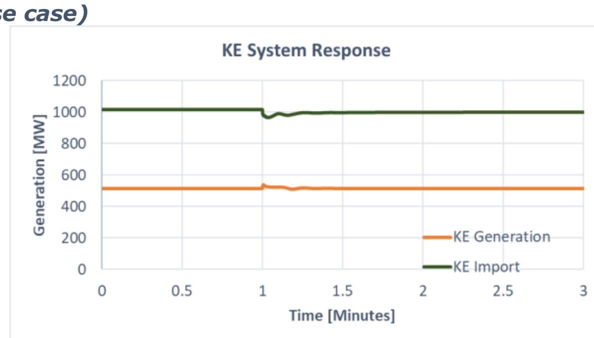

Figure 4-18: KE System response (Summer off-peak base case) Scenario C

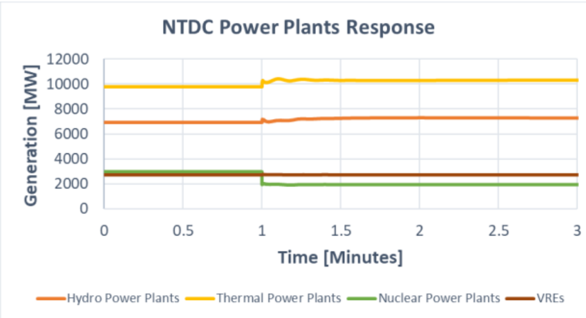

Figure 4-19: NTDC power plant response (Summer off-peak base case) Scenario D

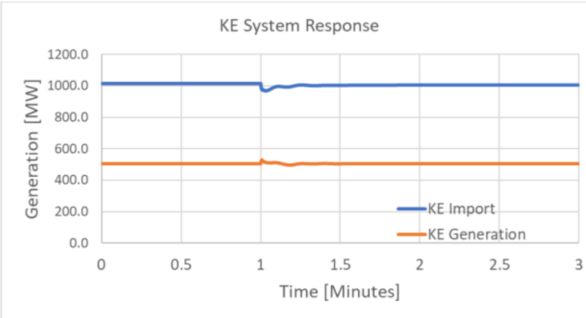

Figure 4-20: KE System response (Summer off-peak base case) Scenario D

Table 4-7: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Summer off-peak base case)

	Scenario – A		Scenario – B		Scenario – C		Scenario – D	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	169		24		256		296	
Thermal	330	20	40	2	507	0	590	0
Nuclear	0		0		0		0	
VREs	0		0		0		0	
Load	480	33	434	32	251	18	136	10
BESS			500	-				
Total Response	979	53	998	34	1014	18	1022	10

4.3 Winter Peak with VRE Integration

Table 4-8 provides the power plants generation, inertia and reserve power available in the NTDC and KE system. The table is showing the category of power plants while the details units online is provided in the Annexure 3. The NTDC system is generating 15,593 MW in which 1,166 MW of power is exported to KE system while KE system is generating 1,372 MW of generation. The inertia is provided in MWs, depends on the MW capacity of power plants it has reduced as thermal power plants are replaced by the VRE generation. The inertia of NTCD power system is 71,290 MWs and frequency regulation characteristics (β) is 3521 MW/Hz depending on the reserve availability and droop settings.

Table 4-8: Power Generation before N-1 contingency (winter peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	1,564	8,613	292	842	-	-	-	
Small Hydro	94	185			-	-	-	
Bagasse	93	407			-	-	-	
Nuclear	3,305	20,108						
Thermal	8,005	41,977	1,684	2679	1,372	6,313	181	653
Wind	1,032				-	-	-	
Solar	1,500				-	-	-	
Total	15,593	71,290	1,976	3521	1,372	6,313	181	653

This case is evaluated with a N-1 contingency, i.e., tripping of K-2 that result in an imbalance of 1032 MW in real time. The power system is than evaluated under four scenarios i.e.:

- Scenario A: Governor dead band is kept at 0.5 Hz
- Scenario B: Governor dead band at 0.5 Hz and BESS of 500 MW is operating
- Scenario C: Governor dead band is kept at 0.2 Hz
- Scenario D: Governor dead band is kept at 0.05 Hz

The system frequency response for all four scenarios is provided in the Figure 4-21 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 4-9. As earlier, governor droop settings are maintained at 4% for all generating units except the steam turbine which is 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be-0.141 Hz/sec and the frequency nadir and steady state frequency will be 48.93 Hz and 49.38 Hz, respectively. The substantial reduction in system frequency is due to reduction in system inertia. The reduction in system inertia results in high ROCOF and reduced frequency nadir and steady state frequency. When this case is evaluated with a BESS of 500 MW, the power system will have ROCOF of -0.108 Hz/sec and the frequency nadir and steady state frequency to 49.28 Hz and 49.50 Hz, respectively. The quick response from the BESS improves the system performance but comparing with base case of section 3.3 replacement of thermal power plants with VREs resulted in lower system inertia and hence increase in ROCOF. Also, when the generating units are operated with a dead band of 0.2 Hz or 0.05 Hz, the system conditions improve from Scenario A. The ROCOF in that case is -0.124 Hz/sec, frequency nadir is 49.07 Hz and steady state frequency is 49.58 Hz. With governor dead band of 0.05 Hz, the ROCOF is -0.115 Hz/sec, Frequency nadir is 49.14 Hz and the Steady state frequency is 49.71 Hz.

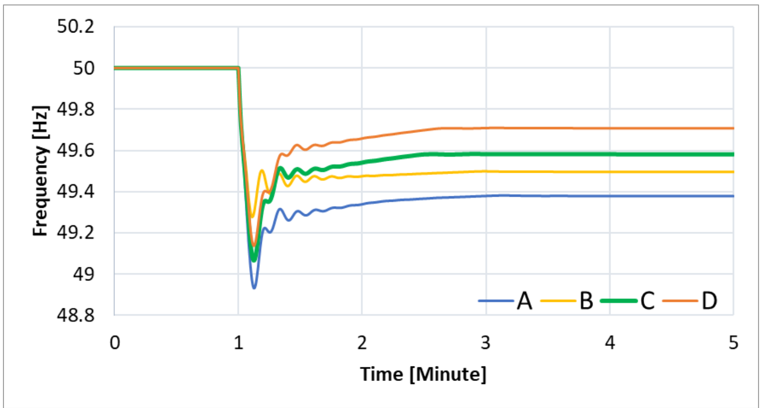

Figure 4-21: System frequency response (winter peak base case)

Table 4-9: Frequency Response after N-1 contingency (Winter peak base case)

	Case – A	Case – B	Case – C	Case – D
ROCOF [Hz/sec]	-0.141	-0.108	-0.124	-0.115
Frequency nadir [Hz]	48.93	49.28	49.07	49.14
Steady state frequency [Hz]	49.38	49.50	49.58	49.71

For the system frequency response presented above, Figure 4-22 to Figure 4-30 shows the response of the power plants in the NTDC system and the KE response through governor action and load damping. The response of the BESS is provided in Figure 4-26 where 500 MW of power is activated in quick time. The dead band and droop settings are the same as the previous cases. Table 4-10 provides the comparison of the four scenarios showing the effective reserves that will be activated under aforementioned governor droop and dead band settings, and the load damping response. Decrease in the load demand during the winter case reduces the load damping for the same amount of contingency. The less load response and lower inertia also result in high frequency variation.

Analyzing this case with the winter peak base case, the reserves regulation burden due to decrease in the generation from the thermal power plants is shifted to hydro power plants. The reserves burden over power plants is minimum with the BESS, i.e., Scenario B. The frequency response and the regulation improve in Scenario C and Scenario D but it is required to maintain specific reserves on all the power plants. The availability of less reserve power or maintain reserves on less generating units hinders the secure operation of power system. For secure operation fast reserves with primary control purpose is required and the quantum have to be equal to the reserves activated in the Scenario – D and have to be distributed over several generating units.

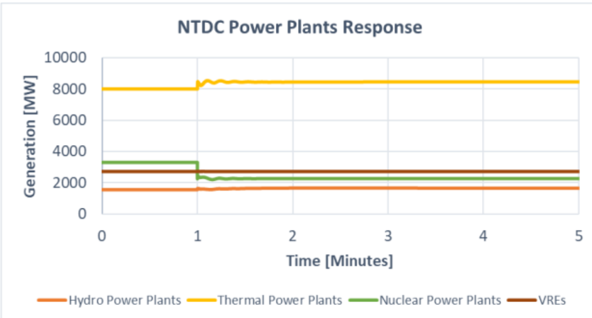

Figure 4-22: NTDC power plant response (Winter peak base case) Scenario A

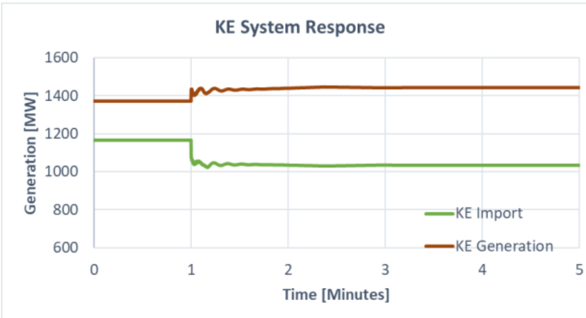

Figure 4-23: KE System response (Winter peak base case) Scenario A

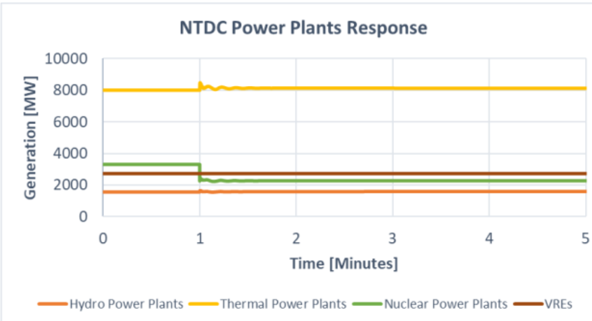

Figure 4-24: NTDC power plant response (Winter peak base case) Scenario B

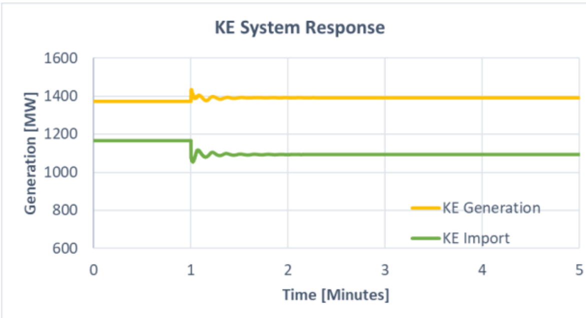

Figure 4-25: KE System response (Winter peak base case) Scenario B

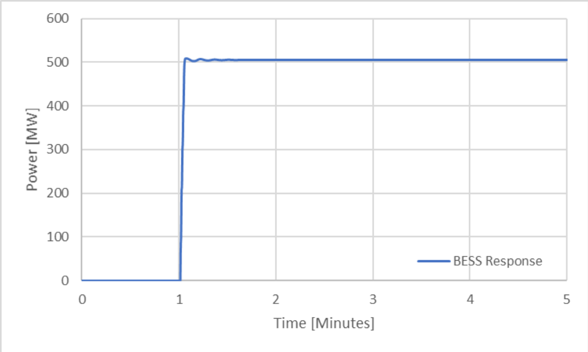

Figure 4-26: BESS response (Winter peak base case)

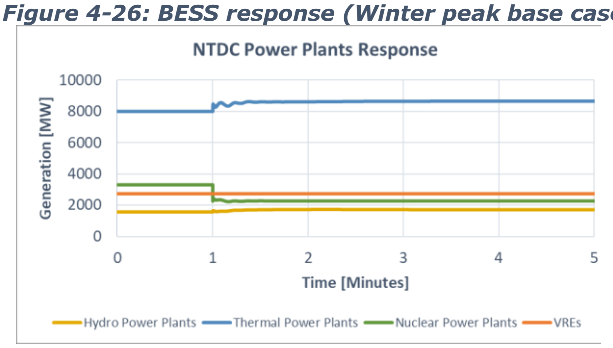

Figure 4-27: NTDC power plant response (Winter peak base case) Scenario C

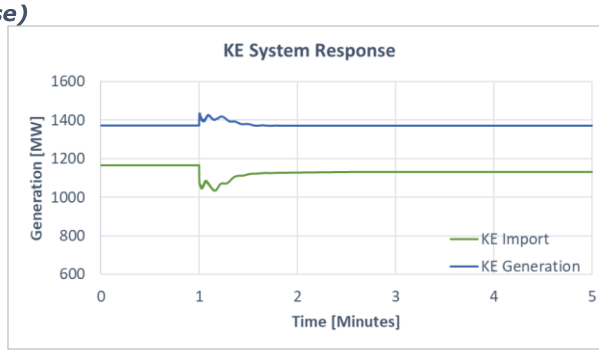

Figure 4-28: KE System response (Winter peak base case) Scenario C

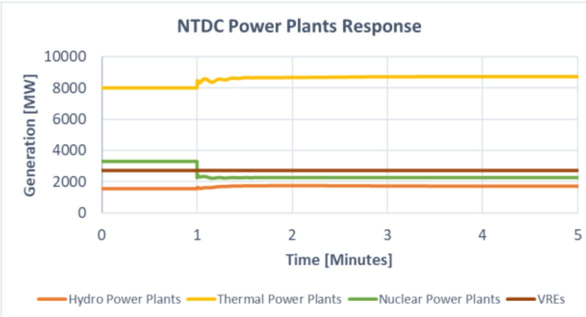

Figure 4-29: NTDC power plant response (Winter peak base case) Scenario D

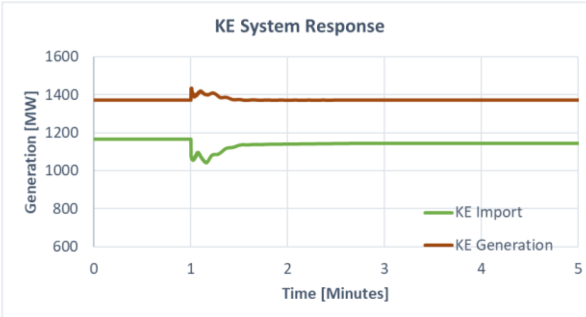

Figure 4-30: KE System response (Winter peak base case) Scenario D

Table 4-10: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Winter peak base case)

	Scenario – A		Scenario – B		Scenario – C		Scenario – D	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	86		4	-	154	-	171	-
Thermal	449	80	184	3	597	0	665	0
Nuclear	0		-	-	-	-	0	-
VREs	0		-	-	-	-	0	-
Load	356	61	290	51	239	42	167	29
BESS			500	-	-	-	-	-
Total Response	891	141	978	54	998	42	1003	29

4.4 Winter Off-Peak with VRE Integration

For this case study, the generation from the power plants along with their inertia and reserve power which is the difference between generated capacity and actual generation is provided in the Table 4-11. The NTDC system is generating 8,440 MW in which 566 MW of power is exported to KE system while KE system is generating 406 MW of generation. In this Scenario again due to the increasing integration of VRE the thermal power plant is kept off that impacts the system inertia provided in MWs. The inertia of NTCD power system is 44,038 MWs and frequency regulation characteristics (β) is 2272 MW/Hz depending on the reserve availability and droop settings. It has to be noted as well that overall solar PV generation capacity is 3000 MW and for wind it is 2800 MW but are only generating 1110 MW and 592 MW respectively. Increase in the generation from solar and wind power will require reducing generation from thermal power plants that will decrease the system inertia even more.

Table 4-11: Power Generation before N-1 contingency (winter off- peak base case)

	NTDC System				KE System			
Plant Type Category	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**	**Power Generation [MW]**	**Inertia [MWs]**	**Reserves [MW]**	**Freq. Reg. (β) [MW/Hz]**
Hydro	486	3,199	200	285	-	-	-	
Small Hydro	68	150			-	-	-	
Bagasse	100	375			-	-	-	
Nuclear	2,490	20,360						
Thermal	3,604	19,953	916	1987	406	3,178	356	360
Wind	592				-	-	-	
Solar	1,110				-	-	-	
Total	8,440	44,038	1,116	2272	406	3,178	356	360

This case of winter off peak with increased VRE is evaluated for N-1 contingency when K-2 trips resulting in an imbalance of 745 MW. The system response is evaluated again for the four scenarios:

- Scenario A: Governor dead band is kept at 0.5 Hz
- Scenario B: Governor dead band at 0.5 Hz and BESS of 500 MW is operating
- Scenario C: Governor dead band is kept at 0.2 Hz
- Scenario D: Governor dead band is kept at 0.05 Hz

The system frequency response for all four scenarios is provided in the Figure 4-31 and the details of ROCOF, frequency nadir and steady state frequency is provided in the Table 4-12. As before, governor droop settings are maintained at 4% for all generating units except the steam turbine which is 5%. The table shows that if the generating units' governor dead band is set at 0.5 HZ, the ROCOF will be -0.147 Hz/sec and the frequency nadir and steady state frequency will be 48.73 Hz and 49.33 Hz, respectively. The contingency on K-2 resulted in an imbalance of 745 MW compared to the previous cases when 1032 MW of imbalance, otherwise the conditions will be more severe.

When this base case is evaluated with an integration of 500 MW BESS, the ROCOF improves to -0.091 Hz/sec and the frequency nadir and steady state frequency to 49.39 Hz and 49.48 Hz, respectively. The BESS stabilizes the system effectively and is more useful in scenario of low inertia. The case when evaluated for governor dead band of 0.2 Hz and 0.05 Hz is effective than Scenario A but not as Scenario B. With governor dead band of 0.2 Hz, the system ROCOF is still high due to low inertia -0.133 Hz/sec, frequency nadir is 48.83 Hz and steady state frequency is 49.57 Hz and with governor dead band of 0.05 Hz, the system ROCOF -0.129 Hz/sec, frequency nadir is 48.87 Hz and steady state frequency is 49.68 Hz. The operation is secure in case of lower inertia only with the integration of BESS.

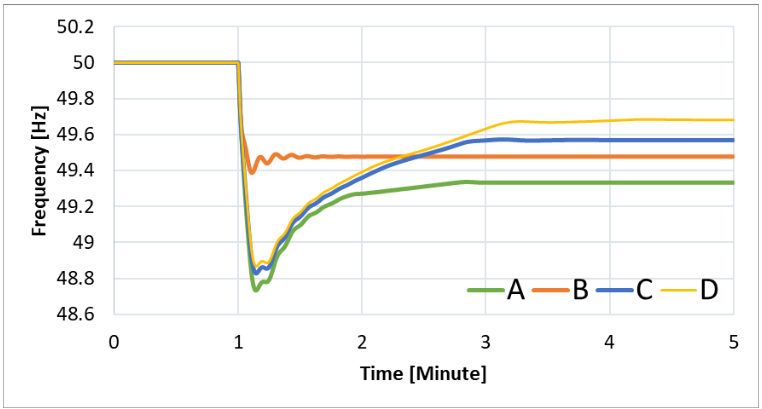

Figure 4-31: System frequency response (winter off peak base case)

Table 4-12: Frequency Response after N-1 contingency (Winter off- peak base case)

	Scenario – A	Scenario – B	Scenario – C	Scenario – D
ROCOF [Hz/sec]	-0.147	-0.091	-0.133	-0.129
Frequency nadir [Hz]	48.73	49.39	48.83	48.87
Steady state frequency [Hz]	49.33	49.48	49.57	49.68

For the system frequency response presented above, the response of the power plants in the NTDC system and the KE response is shown in Figure 4-32 to Figure 4-40 and the response of the BESS in Figure 4-36 where 500 MW of power is activated in quick time. The dead band and droop settings are the same for BESS. i.e., dead band of 0.2 Hz and droop settings of 0.5%.

The four cases for winter off-peak with increased VRE integration are compared in the Table 4-13. The response shows the effective reserves that will be activated under these control settings, i.e., governor droop and dead band settings and the automatic load response with frequency variation. The load damping response has reduced than previous cases as the load demand is lower and with high dead band and low generation capacity the frequency variation is high. The system response will be worse if K-2 was generating high power, i.e., 745 MW as the earlier scenarios. The BESS is more effective in the winter case especially with increased VRE integration as it supports the system with fast acting reserves. The Scenario – C & D shows that the reserves can be effectively activated from the power plants with dead band of 0.2 Hz and 0.05 Hz, as power plants starts to responds earlier with frequency drop, but with less generating units online it is not much effective as the BESS in minimizing ROCOF and frequency nadir.

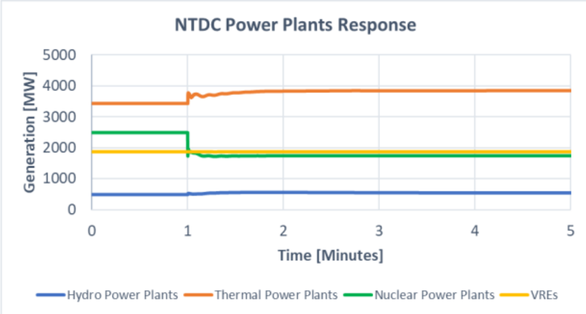

Figure 4-32: NTDC power plant response (Winter off-peak base case) Scenario A

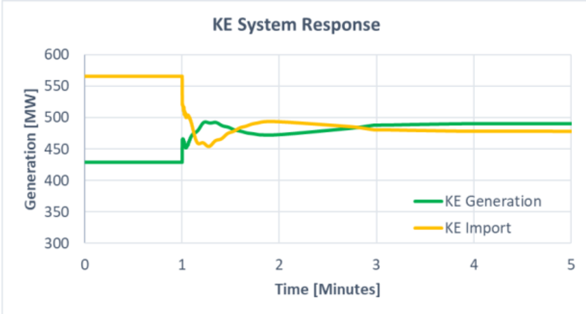

Figure 4-33: KE System response (Winter off-peak base case) Scenario A

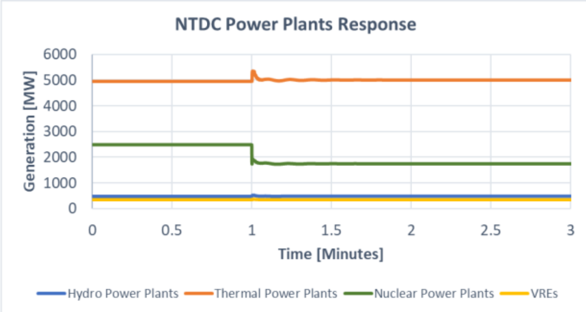

Figure 4-34: NTDC power plant response (Winter off-peak base case) Scenario B

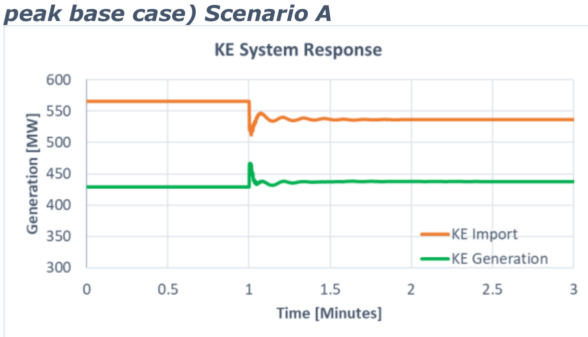

Figure 4-35: KE System response (Winter off-peak base case) Scenario B

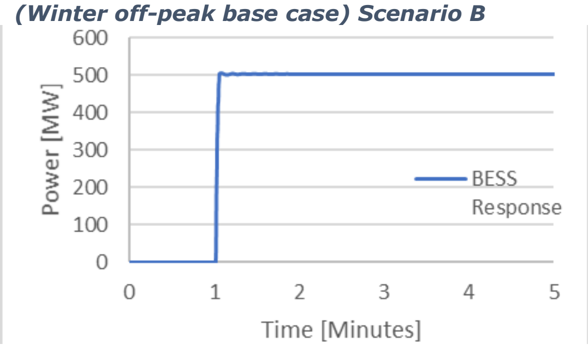

Figure 4-36: BESS Response (Winter off-peak base case)

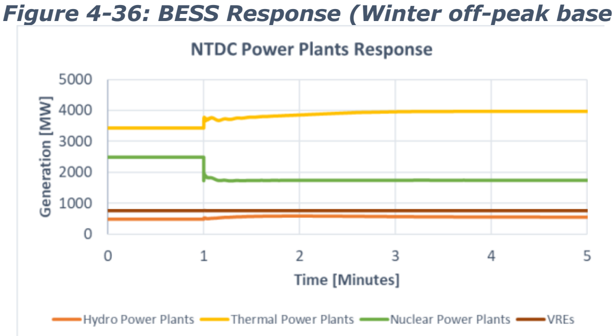

Figure 4-37: NTDC power plant response (Winter off-peak base case) Scenario C

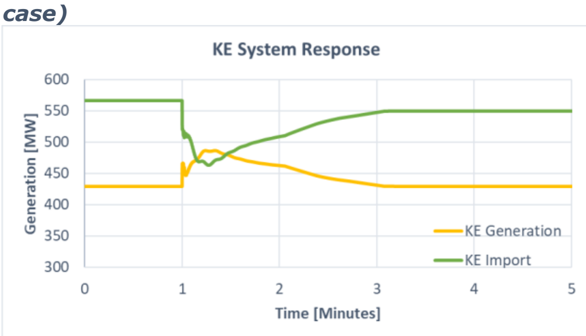

Figure 4-38: KE System response (Winter off-peak base case) Scenario C

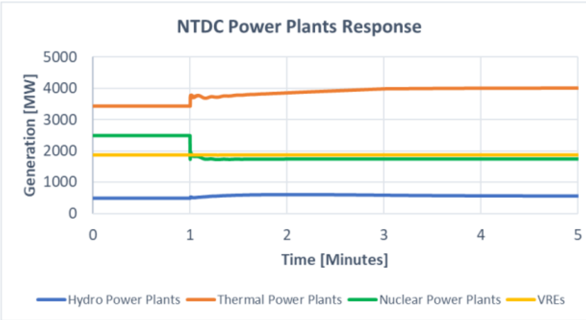

Figure 4-39: NTDC power plant response (Winter off-peak base case) Scenario D

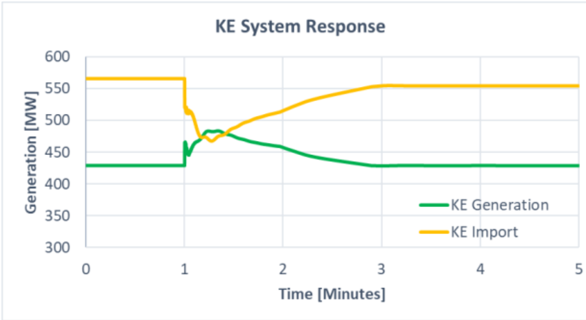

Figure 4-40: KE System response (Winter off-peak base case) Scenario D

Table 4-13: Comparison of Generation and load response for Scenario A, Scenario B & Scenario C during N-1 contingency (Winter off-peak base case)

	Scenario A		Scenario B		Scenario C		Scenario D	
Response	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]	NTDC System [MW]	KE System [MW]
Hydro	40	-	6	-	48	-	54	-
Thermal	414	60	55	-	553	-	586	-
Nuclear	-	-	-	-	-	-	-	-
VREs	-	-	-	-	-	-	-	-
Load	207	24	164	21	132	12	95	10
BESS	-	-	500	-	-	-	-	-
Total Response	661	84	724	21	733	12	735	10

4.5 Section Recommendations

The secure operation of a power system is paramount for maintaining the reliable supply of electricity to society. Frequency control plays a central role in ensuring the stability and functionality of the grid. As power systems continue to evolve with the integration of renewable energy sources, the importance of effective frequency control mechanisms becomes even more critical. Grid operators and policymakers must remain vigilant and adapt to the changing landscape of power system operation to guarantee a resilient and secure energy future.

Considering the case with increased integration VREs, this section evaluates the system performance and need of reserves power in the summers and winters seasons. This study is evaluated again for four scenarios, i.e., speed governor dead band of 0.5 Hz, integration of BESS of 500 MW, speed governor dead band of 0.2 Hz and with 0.05 Hz. In summers, large number of online generating have sufficient inertia to resist ROCOF and system will operate more securely if enough reserves are maintained all major generating units. However, in winters less online generating units due to lower load demand and VRE integration minimizes the system inertia to deal with contingency even when speed governor dead band is kept at 0.2 Hz or 0.05 Hz. System operation can only be made secure during low power demand scenario with the integration of BESS. BESS of at least 500 MW with its quick response will reduce the ROCOF and improves frequency response.

BESS system also minimizes the reserve burden and hence more generating units can operate on the base load as per the merit order.

From study analysis, availability of operating reserves for primary frequency control is only effective if the dead band is kept at 0.05 Hz or at least 0.2 Hz with high frequency regulating characteristics β. The study shows that primary reserves of ±890 MW are needed during summer and ±674 MW during winter when the system is operated as per grid code requirement to deal with the contingency event of 1040 MW. In future with integration of high-power transmission lines and generating units the requirement to deal with N-1 contingency will increase. The primary reserves have to be provided by both NTDC and KE system; KE shall contribute 10% of the total primary reserves, i.e., 88.6 MW and NTDC shall contribute 90% of the required primary reserves, i.e., 797.4 MW. The reserve power of 797.4 MW needs to be placed on generating units that can response with regulation characteristics of at least 6133 MW/Hz. The reserve allocation and frequency regulation are relaxed with BESS of 500 MW and system operate more securely specially in situations of low inertia.

5 Secondary Reserves Requirement for Base cases during N-1 contingency

An active power imbalance resulting in frequency variation from its nominal limit is automatically controlled through speed governor and load damping response. The response depends on the amount of power imbalance, i.e., in case of higher contingency more reserves power is activated from generating units with high load response. These responses stabilize the system frequency at a new level which is either lower or higher than the nominal level depending on the tripping of generating unit or load center, respectively. Although after contingency the power system is balanced at a new level but the system security is at risk to operate the system under these conditions. Any other contingency might lead to situation resulting in system instability.

To operate the power system in a secure manner, the primary reserves and the load response need to be restored and this can be done through activation of secondary reserves. The secondary reserves activated manually or automatically restores the frequency and thereby the primary response. These reserves according to OC 5.4.11.6, shall be maintained in the participating Generators to allow them to vary their MW Output. This section will analyze the system response with the activation of secondary reserves for the above cases when primary response and the load damping have stabilized the system after contingency on biggest generating unit, i.e., K-2. **Each case is analyzed for two scenarios; when reserves are activated from available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario B).** The available generating units are those units that are kept online as per merit order.

5.1 Summer Peak – Base case

The case study has already been discussed in Section 3.1 and the system response is analyzed with N-1 Contingency. For all the scenarios, dead band of 0.5 Hz, 0.2 Hz and 0.05 Hz, and for the BESS, secondary reserves of 1032 MW is needed equal to the amount of contingency to restore the frequency, primary reserves and the load to the original level. For each scenario, Table 5-1 provides the secondary reserves maintained on the generating units along with their ramp rates. As the contingency of k-2 is in the south of the National grid therefore the reserves are also maintained in that region. In Scenario B, the power plant is considered that is operating on its minimum level and with maximum availability of reserves power that can be activated with high ramp rates.

Table 5-1: Secondary Reserves with their Ramp Rates for Summer Peak Base case

Scenario – A			Scenario – B		
Power Plants	**Secondary Reserves [MW]**	**Ramp rates [MW/min]**	**Power Plants**	**Secondary Reserves [MW]**	**Ramp rates [MW/min]**
Power Plant A	259	13.2	**Power Plant 1**	960	36
Power Plant B	120	13.2	**Power Plant 2**	72	13.2
Power Plant C	303	8.9		-	-
Power Plant D	350	7.92		-	-
Total	1032 MW	43.22 MW/min		1032 MW	49.2 MW/min

The reserve activation process from the two sets of thermal generating units is shown in Figure 5-1. In Scenario A, although multiple generating units have activated the reserve power at the same time but due to their slower ramp rate the reserves activation process takes almost 25 minutes while in Scenario B the secondary reserves are activated in 22 minutes due to high ramp rate of Power Plant 1 compared to other power plants. With the activation of secondary reserves, the system frequency is provided in Figure 5-2 and the hydro power plants response, load response and KE response in Figure 5-3, Figure 5-4 and Figure 5-5, respectively.

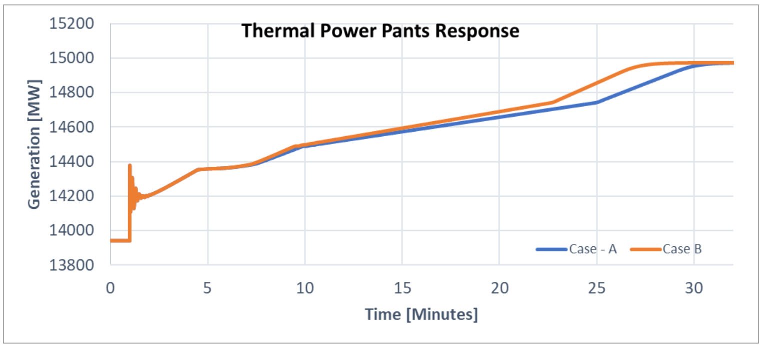

Figure 5-1: Secondary Reserves Activation from Thermal power plants (Summer Peak Base case)

Figure 5-2 shows that for the both scenarios with the activation of secondary reserves the frequency normalizes and as the frequency is restored the primary reserves from the hydro power plants and the load response also normalizes. The secondary reserves are only activated from the thermal power plants provided in Table 5-1, so the thermal power plants that have participated in the primary control action will restore their reserves as the frequency restores. Also, the KE generating units and the load in the KE system restores their initial operating condition with the restoration of frequency.

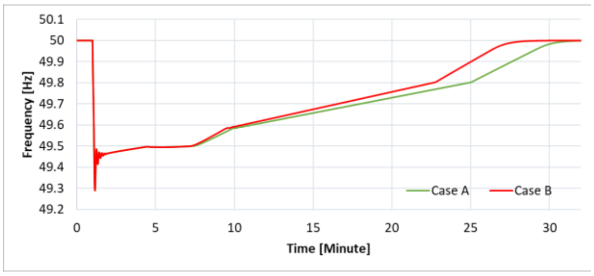

Figure 5-2: System Frequency Response (Summer Peak Base case)

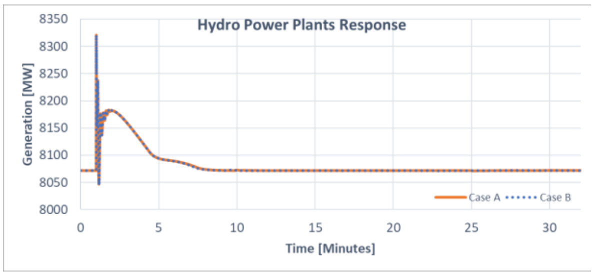

Figure 5-3: Hydro Power Plants response (Summer Peak Base case)

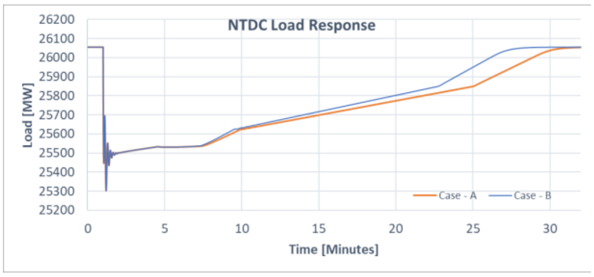

Figure 5-4: NTDC Load Response (Summer Peak Base case)

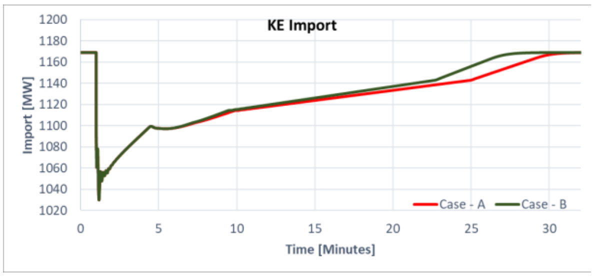

Figure 5-5: KE System Response (Summer Peak Base case)

5.2 Summer Off-Peak – Base case

This section will analyze the base case for secondary control when primary response after N-1 contingency is provided by the generating units and the load in the NTDC and KE system. This case study has already been discussed in Section 3.2 and the system response after primary control is analyzed with N-1 Contingency. Here the system is analyzed for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario B). The Table 5-2 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 5-2: Secondary Reserves with their Ramp rates for Summer Off-Peak Base case

Scenario – A			**Scenario – B**		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	303	8.9	**Power Plant 1**	960	36
Power Plant B	240	13.2	**Power Plant 2**	72	13.2
Power Plant C	355	7.92			
Power Plant D	134	13.2			
Total	1032 MW	43.22 MW/min	**Total**	1032 MW	49.2 MW/min

The above set of thermal generating units provides the required response. The response from both set of generating units are presented in Figure 5-6, where generating units in Scenario – A achieved its output in 25 minutes compared to Scenario – B which has activated 1032 MW of reserves in 22 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 5-7 and the hydro power plants response, load response and KE response in Figure 5-8, Figure 5-9 and Figure 5-10, respectively. The Figure 5-7 shows that frequency is restored for the both Scenarios with the activation of secondary reserves. When frequency is restored the primary reserves from the hydro and thermal power plants and the load response also restored to initial operating conditions. The secondary reserves are only activated from the set of thermal power plants provided in Table 5-2, so the remaining units of thermal power plants that have participated in the primary control action will also restore their reserves as the frequency normalize. KE system has responded to stabilize the power system but with the activation of secondary reserves the KE generating units and the load in the KE system restores their initial operating condition.

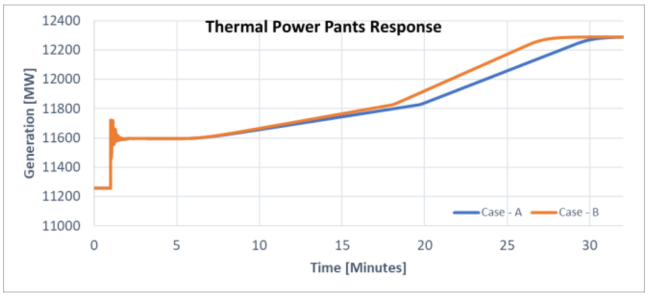

Figure 5-6: Secondary Reserves Activation from Thermal power plants (Summer Off-Peak Base case)

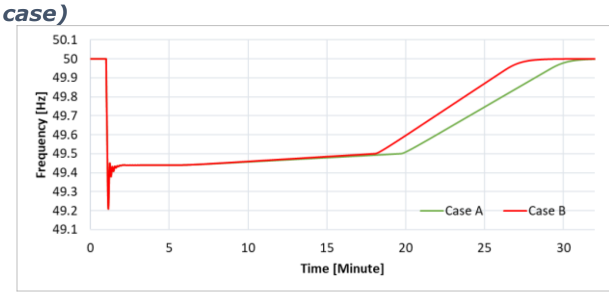

Figure 5-7: System Frequency Response (Summer Off-Peak Base case)

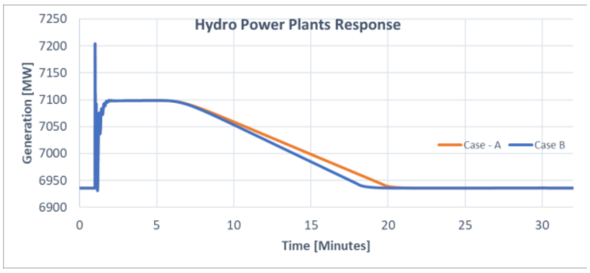

Figure 5-8: Hydro Power Plants response (Summer Off-Peak Base case)

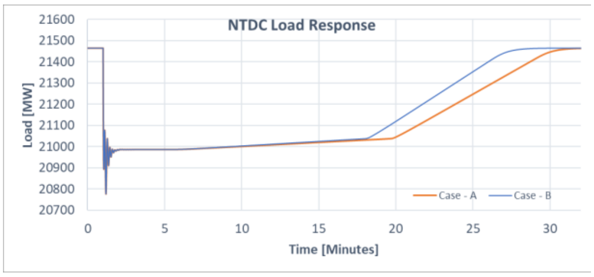

Figure 5-9: NTDC Load Response (Summer Off-Peak Base case)

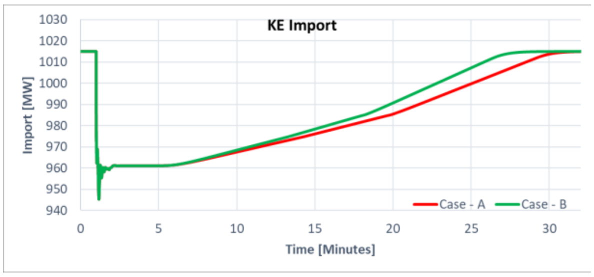

Figure 5-10: KE System Response (Summer Off-Peak Base case)

5.3 Winter Peak – Base Case

Winter peak base case is analyzed for secondary control when primary response after N-1 contingency is already provided by the generating units and the load in the NTDC and KE system. This case study has already been discussed in Section 3.3 and the system response after primary control is analyzed with N-1 Contingency. Here the system is studied for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario B). The Table 5-3 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 5-3: Secondary Reserves with their Ramp rates for Winter Peak Base case

Scenario – A			**Scenario – B**		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	303	8.9	**Power Plant 1**	960	36
Power Plant B	380	13.2	**Power Plant 2**	72	13.2
Power Plant C	350	7.92			
Total	1032 MW	30.02 MW/min		1032 MW	49.2 MW/min

The above set of thermal generating units in Scenario – A and Scenario – B provides the required response and are presented in Figure 5-11, where generating units in Scenario – A achieved its output in 37 minutes compared to Scenario – B which has activated 1032 MW of reserves in 22 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 5-12 and the hydro power plants response, load response and KE response in Figure 5-13, Figure 5-14 and Figure 5-15, respectively. The Figure 5-12 shows that frequency is restored for the both Scenarios with the activation of secondary reserves. With the restoration of frequency to nominal level, the primary reserves from the hydro and thermal power plants and the load response also restored to initial operating conditions. The secondary reserves are only activated from the set of thermal power plants provided in Table 5-3, so the remaining units of thermal power plants that have participated in the primary control action will also restore their reserves as the frequency is restored. From Figure 5-15, KE system response also restores their initial operating condition.

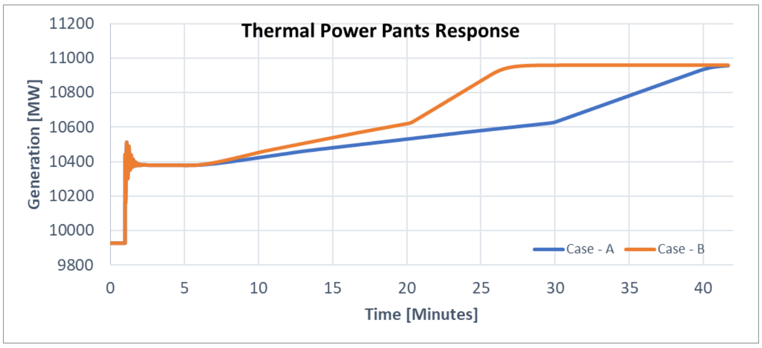

Figure 5-11: Secondary Reserves Activation from Thermal power plants (Winter Peak Base case)

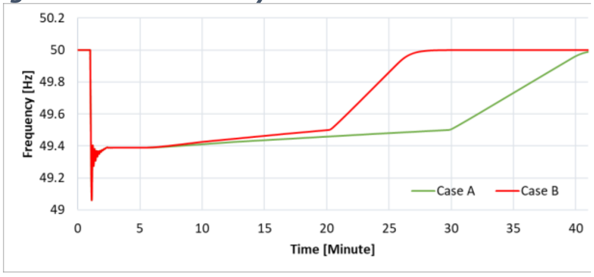

Figure 5-12: System Frequency Response (Winter Peak Base case)

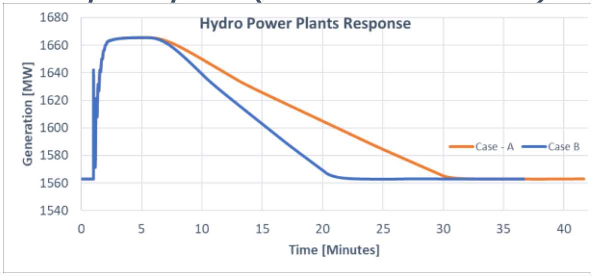

Figure 5-13: Hydro Power Plants response (Winter Peak Base case)

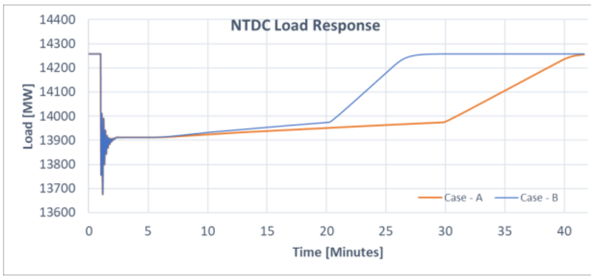

Figure 5-14: NTDC Load Response (Winter Peak Base case)

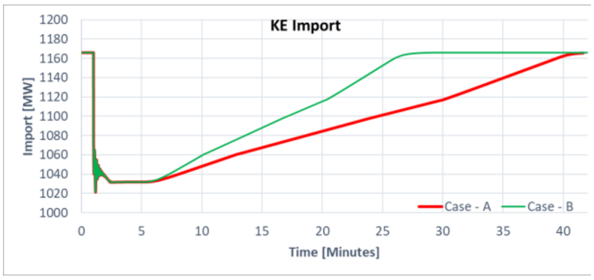

Figure 5-15: KE System Response (Winter Peak Base case)

5.4 Winter Off-Peak – Base Case

Winter off peak base case is analyzed for secondary control when primary response after N-1 contingency is already provided by the generating units and the load in the NTDC and KE system and have been discussed in Section 3.4. Here the system response is studied for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario B). The Table 5-4 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 5-4: Secondary Reserves with their Ramp rates for Winter Off-Peak Base case

Scenario – A			**Scenario – B**		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	303	8.9	**Power Plant 1**	720	27
Power Plant B	450	13.2	**Power Plant 2**	25	13.2
Total	753 MW	22.1 MW/min	**Total**	745 MW	30.2 MW/min

The above set of thermal generating units in Scenario – A and Scenario – B provides the required response and are presented in Figure 5-16, where generating units in Scenario – A achieved its output in 35 minutes compared to Scenario – B which has activated 745

MW of reserves in 20 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 5-17 and the hydro power plants response, load response and KE response in Figure 5-18, Figure 5-19 and Figure 5-20, respectively. The Figure 5-17 shows that frequency is restored for the both Scenarios with the activation of secondary reserves. When frequency is restored the primary reserves from the hydro & thermal power plants and the load response also restored to initial operating conditions. The secondary reserves are only activated from the set of thermal power plants provided in Table 5-4. The generating units within the KE network and the load response is also restored when frequency is restored to 50 Hz after activation of secondary reserves.

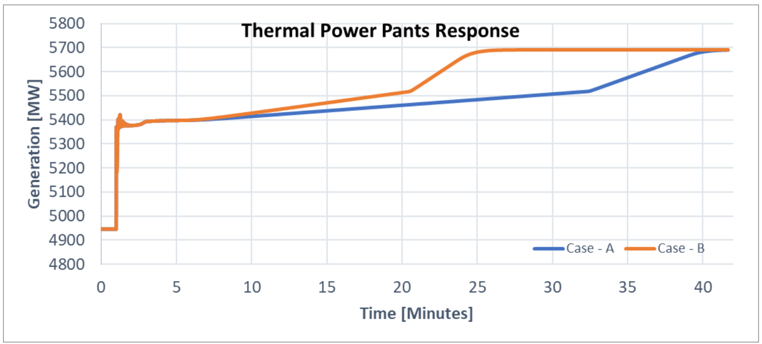

Figure 5-16: Secondary Reserves Activation from Thermal power plants (Winter Off-Peak Base case)

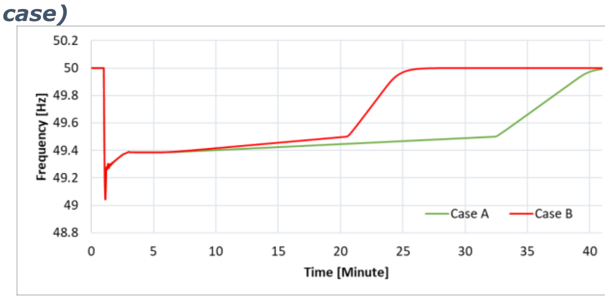

Figure 5-17: System Frequency Response (Winter Off-Peak Base case)

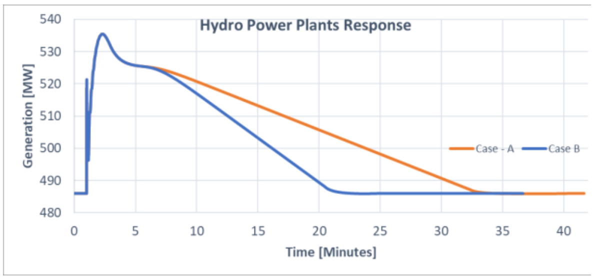

Figure 5-18: Hydro Power Plants response (Winter Off-Peak Base case)

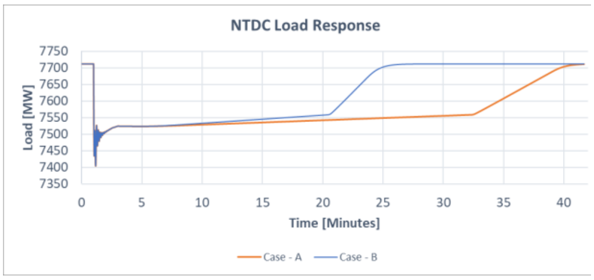

Figure 5-19: NTDC Load Response (Winter Off-Peak Base case)

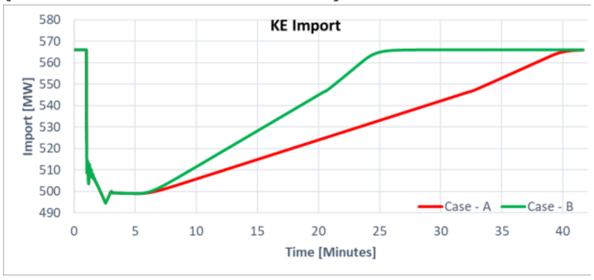

Figure 5-20: KE System Response (Winter Off-Peak Base case)

5.5 Financial Analysis

The technical details are discussed in detail above, this section provides the financial analysis for each of the scenarios discussed. The generation cost is provided in the Table 5-5 and the detailed costs of generation of each power plants is provided in Annexure 4. Comparing the two scenarios for each of the base cases, it can be observed that the cost of scenario B is lower than Scenario A. The fast ramping generating units not only secure power system operations but also reduces the overall operating cost. Maintaining secondary reserves on fast ramping generating units allows the base load power plants to be operated on their maximum level and results in reduction in generation cost. If base load power plants are scheduled for secondary control, it not only impacts the system security, generation health but also increases the operating cost.

Table 5-5: Generation cost for Scenario A and Scenario for Base Cases

	Scenario A		Scenario B	
Base cases	Total Generation [MW]	Generation Cost [PKR/hour]	Total Generation [MW]	Generation Cost [PKR/hour]
Summer Peak	27,214	352,732,674	27,214	335,862,377
Summer Off-peak	22,470	248,828,452	22,470	248,739,958
Winter Peak	15,593	197,758,886	15,593	194,977,734
Winter Off-peak	8,268	73,280,525	8,268	76,400,373

Note: Estimated or averaged generation rates are used for the power plants for which the rate is not known.

5.6 Section Recommendations

The section provides an overview of NTDC power system during different operating conditions of the summers and winters in case of N-1 contingency. The study evaluated each base case for two scenarios, i.e., when secondary reserves are maintained on available generating units and when secondary reserves are maintained on fast ramp power plants. Analyzing the above case, secondary reserves equal to the largest generating unit need to be maintained all the time, in our case secondary reserves of 1040 MW, for secure operation of the power system.

When secondary reserves are maintained on available generating units (that are online as per merit order), these generators need to be operated close to their minimum power level and will be dispatched regularly when secondary reserves are required. The availability of secondary reserves on fast ramp generating units reduces system restoration time thereby improving system security. The financial analysis also shows that generation cost will be lower if secondary reserves are maintained on fast ramping generating units.

6 Secondary Reserves Requirement for cases with increased VRE during N-1 contingency

The large-scale integration of VREs impacts the real-time system operation. The integration of VERs replaces the conventional generating units and thereby the provision of ancillary services especially the frequency control reduces. With less generating units online, the volume of secondary reserves for dealing N-1 contingency also reduces. This section analyses the response for secondary reserves in case of N-1 contingency when 2500 MW of solar PV and 1000 MW of wind is integrated as discussed in Section 4 of this report. In this section again the four Scenarios of summer and winter will be discussed when secondary reserves are activated from online available generating units and from fast ramping generating units. The cases are analyzed again for two scenarios; when reserves are activated from available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario – B).

6.1 Summer Peak Case with increased VRE

The case study has already been discussed in Section 4.1 and the system response is analyzed with N-1 Contingency. To mitigate the imbalance secondary reserves of 1032 MW is required that is equal to the amount of contingency to restore the frequency, primary reserves and the load response. This case is analyzed again for two scenarios; when reserves are activated from available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario – B). The Table 6-1 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 6-1: Secondary Reserves with their Ramp rates for Summer Peak Base case

Scenario – A			Scenario – B		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	259	13.2	**Power Plant 1**	960	36
Power Plant B	120	13.2	**Power Plant 2**	72	13.2
Power Plant C	303	8.9		-	-
Power Plant D	350	7.92		-	-
Total	1032 MW	43.22 MW/min		1032 MW	49.2 MW/min

The reserve activation process from the two sets of thermal generating units is shown in Figure 6-1. In Scenario A, although multiple generating units have activated the reserve power at the same time but the reserves activation process takes almost 25 minutes while in Scenario B the secondary reserves are activated in 22 minutes due to the faster response from Power Plant 1. With the activation of secondary reserves, the system frequency is provided in Figure 6-2 and the hydro power plants response, load response and KE response in Figure 6-3, Figure 6-4 and Figure 6-5, respectively. Figure 6-2 shows that for the both scenarios with the activation of secondary reserves the frequency normalizes and as the frequency is restored the primary reserves from the hydro & thermal power plants and the load response also normalizes. The secondary reserves are only activated from the thermal power plants provided in Table 6-1, so the thermal power plants that have participated in the primary control action will restore their reserves as the frequency restores. Also, the KE generating units and the load in the KE network restores to their initial operating condition with the restoration of frequency.

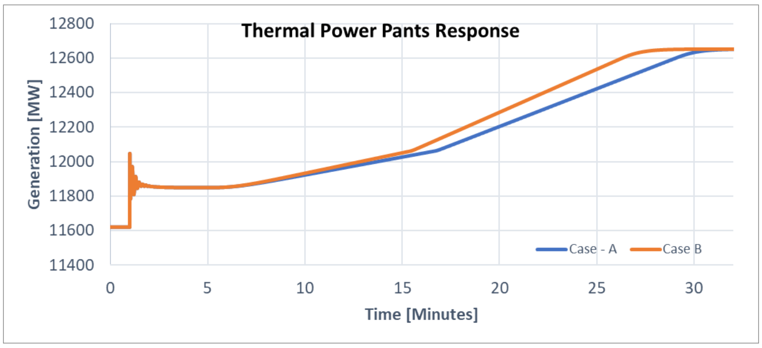

Figure 6-1: Secondary Reserves Activation from Thermal power plants (Summer Peak case with VRE)

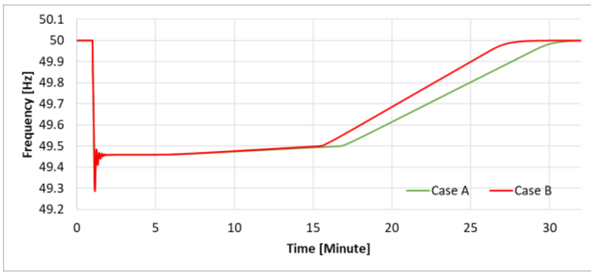

Figure 6-2: System Frequency Response (Summer Peak Base case with VRE)

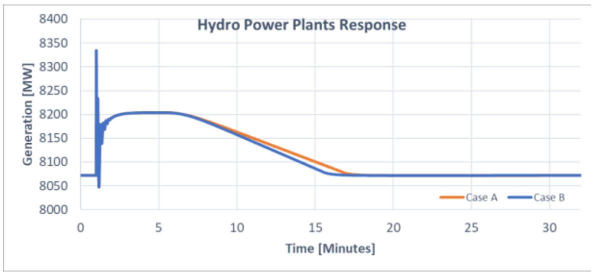

Figure 6-3: Hydro Power Plants response (Summer Peak Base case with VRE)

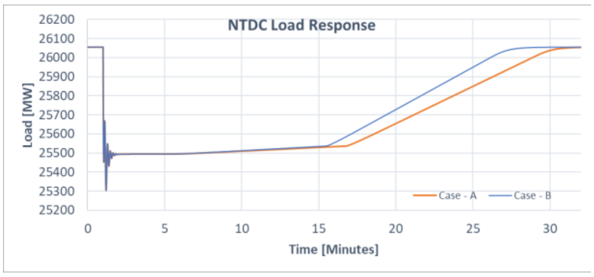

Figure 6-4: NTDC Load Response (Summer Peak Base case with VRE)

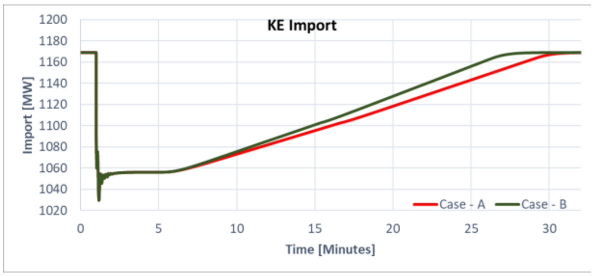

Figure 6-5: KE System Response (Summer Peak Base case with VRE)

6.2 Summer Off-Peak Case with increased VRE

This section will analyze the VRE integrated case for secondary control when primary response after N-1 contingency is provided by the generating units and the load in the NTDC and KE system. This case study has already been discussed in Section 4.2 and the system response after primary control is analyzed with N-1 Contingency. Here the system is analyzed for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario – B). The Table 6-2 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 6-2: Secondary Reserves with their Ramp rates for Summer Off-Peak Base case

Scenario – A			**Scenario – B**		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]

Power Plant A	303	8.9	**Power Plant 1**	960	36
Power Plant B	134	13.2	**Power Plant 2**	72	13.2
Power Plant C	355	7.92			
Power Plant D	240	13.2			
Total	1032 MW	43.22 MW/min		1032 MW	49.2 MW/min

The above set of thermal generating units provides the required response that are presented in Figure 6-6, where generating units in Scenario – A achieved its output in 25 minutes compared to Scenario – B which has activated 1032 MW of reserves in 22 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 6-7 and the corresponding hydro power plants response, load response and KE response in Figure 5-8, Figure 5-9 and Figure 5-10, respectively. Figure 5-7 shows that frequency is restored for both scenarios with the activation of secondary reserves in different time duration and as a result the hydro & thermal power plants and the load response also restore to initial operating conditions. The secondary reserves are only activated from the set of thermal power plants provided in Table 6-2, so the remaining units of thermal power plants that have participated in the primary control action will also restore their reserves when frequency normalize.

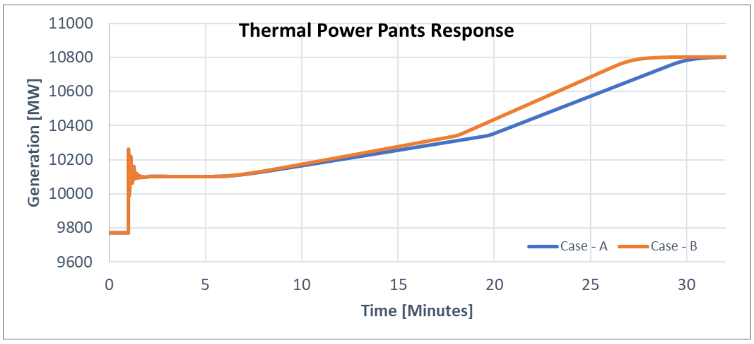

Figure 6-6: Secondary Reserves Activation from Thermal power plants (Summer Off-Peak Base case with VRE)

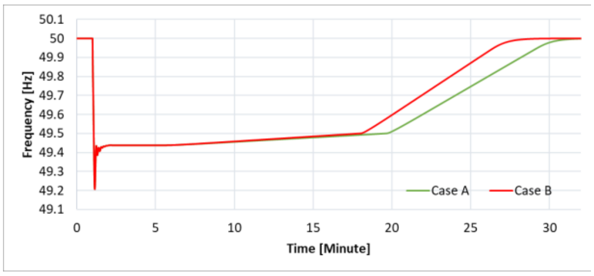

Figure 6-7: System Frequency Response (Summer Off-Peak Base case with VRE)

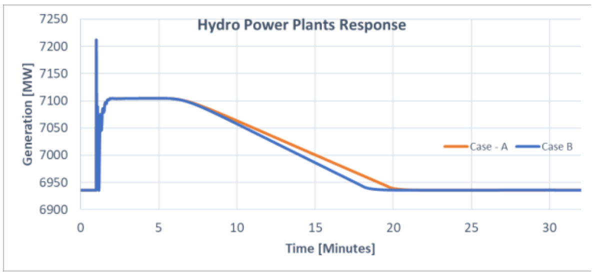

Figure 6-8: Hydro Power Plants response (Summer Off-Peak Base case with VRE)

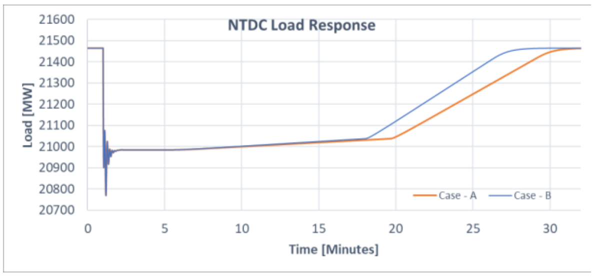

Figure 6-9: NTDC Load Response (Summer Off-Peak Base case with VRE)

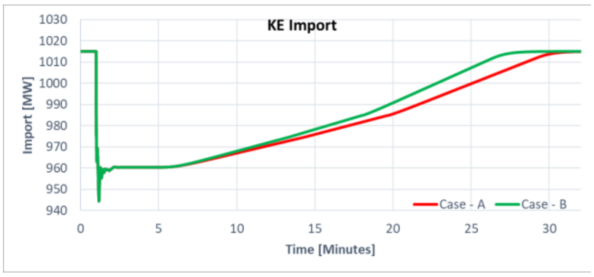

Figure 6-10: KE System Response (Summer Off-Peak Base case with VRE)

6.3 Winter Peak Case with increased VRE

VRE integrated winter peak case is analyzed for secondary control when primary control stabilizes the system frequency to a new steady state level after N-1 contingency. This case study has already been discussed in Section 4.3. Here the system is studied for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario – B). The Table 6-3 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 6-3: Secondary Reserves with their Ramp rates for Winter Peak Base case

Scenario – A			Scenario – B		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	303	8.9	**Power Plant 1**	960	36
Power Plant B	630	13.2	**Power Plant 2**	72	13.2
Power Plant C	100	3.3			
Power Plant D	100	3.3			
Total	1032 MW	28.7 MW/min	**Total**	1032 MW	49.2 MW/min

The above set of thermal generating units in Scenario – A and Scenario – B provides the required response and are presented in Figure 6-11, where generating units in Scenario – A achieved its output in 37 minutes compared to Scenario – B which has activated 1032 MW of reserves in 22 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 6-12 and the hydro power plants response, load response and KE response in Figure 6-13, Figure 6-14 and Figure 6-15, respectively. The Figure 6-12 shows that frequency is restored for the both Scenarios with the activation of secondary reserves. When frequency is restored the primary reserves from the hydro & thermal power plants and the load response is also restored to initial operating conditions.

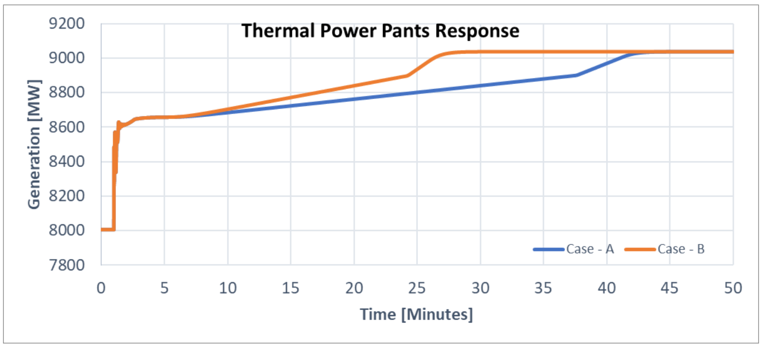

Figure 6-11: Secondary Reserves Activation from Thermal power plants (Winter Peak Base case with VRE)

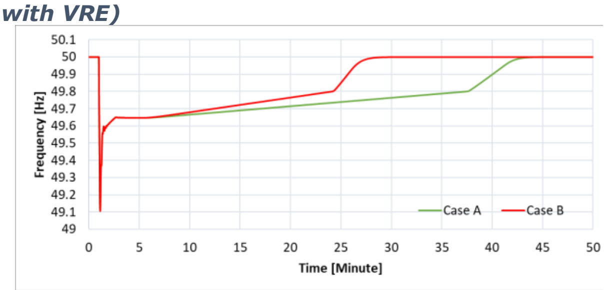

Figure 6-12: System Frequency Response (Winter Peak Base case with VRE)

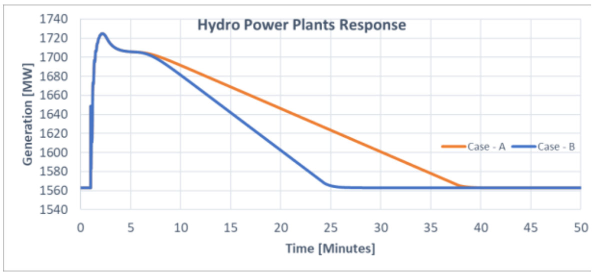

Figure 6-13: Hydro Power Plants response (Winter Peak Base case with VRE)

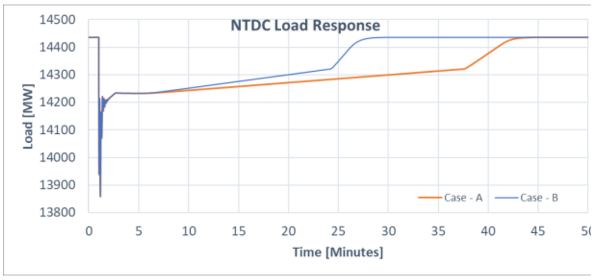

Figure 6-14: NTDC Load Response (Winter Peak Base case with VRE)

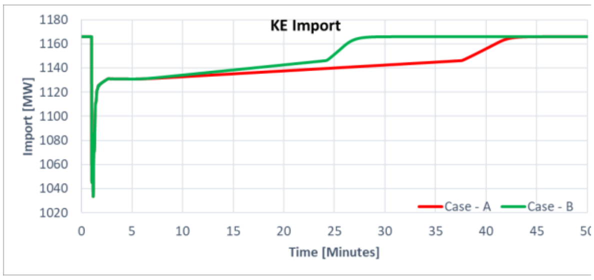

Figure 6-15: KE System Response (Winter Peak Base case with VRE)

6.4 Winter Off-Peak Case with increased VRE

VRE integrated winter off peak case is analyzed for secondary control when primary response after N-1 contingency is already provided by the generating units and the load in the NTDC and KE system and have been discussed in Section 3.4. Here the system response is studied for secondary control when reserves are activated from set of available generating units (Scenario A) and when reserves are activated from generating unit with fast ramp rate (Scenario – B). The Table 6-4 provides the secondary reserves maintained on the generating units along with their ramp rates.

Table 6-4: Secondary Reserves with their Ramp rates for Winter Off-Peak Base case

Scenario – A			**Scenario – B**		
Power Plants	Secondary Reserves [MW]	Ramp rates [MW/min]	**Power Plants**	Secondary Reserves [MW]	Ramp rates [MW/min]
Power Plant A	95	3.3	**Power Plant 1**	720	27
Power Plant B	650	13.2	**Power Plant 2**	25	13.2
Total	745 MW	16.5 MW/min	**Total**	745 MW	40.2 MW/min

The above set of thermal generating units in Scenario – A and Scenario – B provides the required response and are presented in Figure 6-16, where generating units in Scenario – A achieved its output in 37 minutes compared to Scenario – B which has activated 745 MW of reserves in 18 minutes. With the activation of secondary reserves, the system frequency is provided in Figure 6-17 and the hydro power plants response, load response and KE response in Figure 6-18, Figure 6-19 and Figure 6-20, respectively. The Figure 6-17 shows that frequency is restored for the both Scenarios with the activation of secondary reserves. When frequency is restored the primary reserves from the hydro & thermal power plants and the load response restore to initial operating conditions. From Figure 6-20, the generating units within the KE network and the load response also restores when frequency normalize.

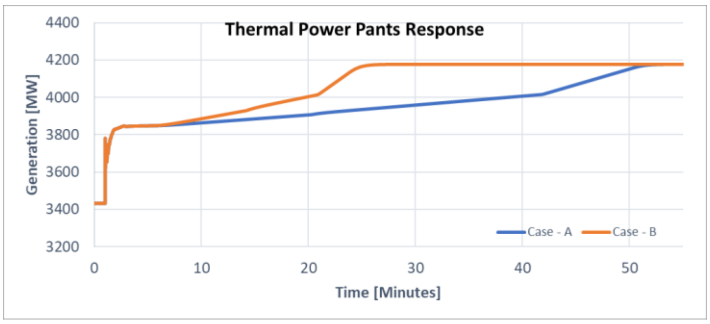

Figure 6-16: Secondary Reserves Activation from Thermal power plants (Winter Off-Peak Base case with VRE)

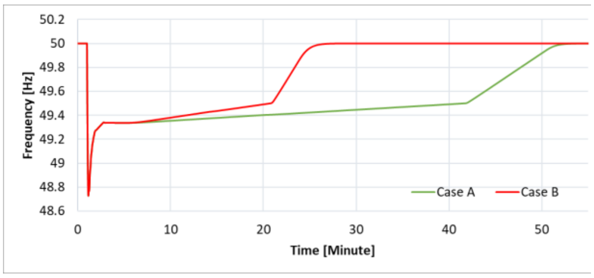

Figure 6-17: System Frequency Response (Winter Off-Peak Base case with VRE)

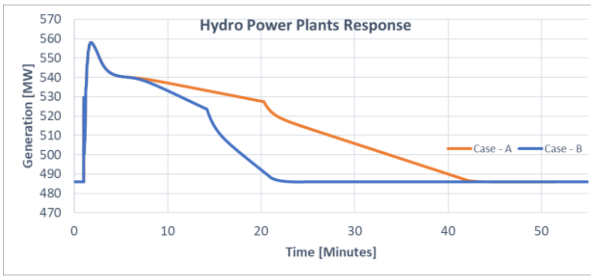

Figure 6-18: Hydro Power Plants response (Winter Off-Peak Base case with VRE)

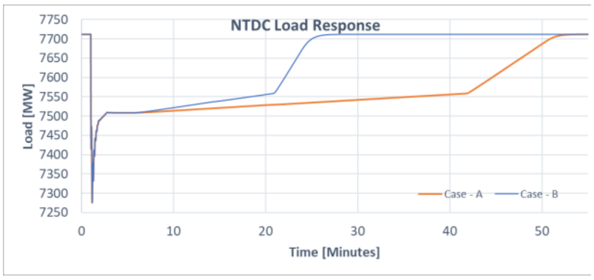

Figure 6-19: NTDC Load Response (Winter Off-Peak Base case with VRE)

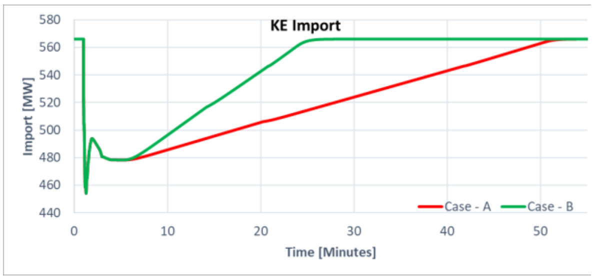

Figure 6-20: KE System Response (Winter Off-Peak Base case with VRE)

6.5 Financial Analysis

For each of the scenarios discussed above in this section, the generation cost is provided in the Table 6-5. The detailed cost of generation of each power plants is provided in Annexure 4. Comparing the two scenarios for each of the VRE integrated cases, it can be observed that the cost of scenario B is lower than Scenario A. The fast ramping generating units not only secure power system operations but also reduces the overall operating cost. Maintaining secondary reserves on fast ramping generating units allows the base load power plants to be operated on their maximum level and results in reduction in generation cost. If base load power plants are scheduled for secondary control, it not only impacts the system security, generation health but also increases the operating cost.

Table 6-5: Generation cost for Scenario A and Scenario for VRE integrated Cases

	Scenario A		**Scenario B**	
VRE Integrated cases	Total Generation [MW]	Generation Cost [PKR/hour]	Total Generation [MW]	Generation Cost [PKR/hour]
Summer Peak	27,214	327,563,804	27,214	318,783,680
Summer Off-peak	22,470	229,131,142	22,470	223,731,675
Winter Peak	15,593	172,389,615	15,593	176,850,115
Winter Off-peak	8,440	77,465,440	8,440	70,378,564

Note: Estimated or averaged generation rates are used for the power plants for which the rate is not known.

6.6 Section Recommendations

With increasing integration of VREs, the secondary reserve requirement for NTDC power system is evaluated during different operating conditions of the summers and winters in case of N-1 contingency. As the contingency is the same as the previous section, the secondary reserves requirement remains equivalent. The integration of VRE in future will replace thermal generating units but for secure operation of the power system the importance of provisioning secondary reserves from fast ramp generating units increases. If secondary reserves are maintained on available generating units (that are online as per merit order), they need to be operated close to their minimum power level and will be dispatched regularly. However, if extra generating units with fast ramp rates activates the secondary reserves, the system will normalize in less time. This will allow base load power plants to operate closer to their maximum level.

The financial analysis also shows that generation cost will be lower if base load power plants are operated close to the maximum level and secondary reserves are maintained on fast ramping generating units. Although Grid code have specified the minimum load, ramp up/down capability of thermal generating units (specified in the CC 6.2.1 (h)) but presently most of the power plants do not meet the criteria. **With increasing VRE integration fast ramping generating units are necessary for secure operation of the power system.**

7 Tertiary response during N-1 contingency

Tertiary frequency response represents the third level of reserves activation in the hierarchy of reserve categories used in electrical grid management. These reserves are essential for maintaining stability of the grid by responding to significant disturbances that affect the grid's frequency. These disturbances include large generator or transmission line failures, sudden load changes, or extreme weather events. Tertiary contingency reserves are designed to address events that are less frequent but more severe than those typically handled by primary and secondary reserves.

Tertiary reserves have a longer response time compared to primary and secondary reserves. They need to be activated within 30 minutes to a few hours, depending on the specific grid's requirements. Tertiary reserves can be sourced from a combination of resources, including fast-start natural gas power plants. These power plants can be brought online relatively quickly and provide a significant amount of power. The number of tertiary reserves required is determined by the operating conditions. NTDC system will require fast ramping non spinning reserves of 1000 MW in addition to secondary reserves of 1040 MW to deal with worst contingencies, i.e., N-2 contingency like when both k-2 and k-3 nuclear power plants trips.

8 Normal operating Reserves

Section 3 to section 7 describe the requirement for operating reserves to deal with N-1 contingency. Apart from the contingency the imbalances are also caused by various factors, including inaccurate forecasts of load, wind, and solar power generation. To handle these active power imbalances, normal operating reserves are required and the type and amount of reserve power needed depend on the specific nature and amount of the imbalance.

Errors in predicting electricity demand (load) can lead to imbalances. If the forecast underestimates the load, there may not be enough supply, conversely, if the forecast overestimates the load, there may be an excess supply, which can strain the grid or result in curtailment of excess generation. Likewise, VRE sources like wind and solar power are challenging to forecast accurately due to their inherent variability. Errors in forecasting VRE generation can lead to unexpected fluctuations in supply. An underestimation of VRE output may result in insufficient supply, while an overestimation can lead to grid instability. To deal with the active power imbalances arising due to forecast error, regulating and following reserves are required which are also known as normal operating secondary and tertiary reserves.

8.1 Regulating Reserves

To address active power imbalances caused by forecast errors, grid operators need reserve power to ensure grid stability. Regulating reserve are the secondary reserve operated that are activated within tens of minutes to address imbalances. The quantum of reserves required to deal with the imbalances depends on the forecast error. However, here we will consider the grid code as a reference and based on the allowable forecasting error the reserve margin is calculated. According to OC 2.8 of the grid code, daily mean absolute percentage error (MAPE) for demand forecast have to be less than 3%, where MAPE is calculated as:

$$MAPE = \frac{Actual\ load - forecast\ load}{Actual\ Load} * 100$$

Also, according to the SDC 1 Appendix – E, for hour-ahead intraday generation forecasts, the desired forecast accuracy for VRE measured in terms of P95 of the absolute percentage error is 10%. Although for day-ahead generation forecasts, the desired forecast accuracy is 15% but here we will calculate the reserve based on 10% forecast error. The absolute percentage error (APE) for VRE forecast is calculated as:

$$APE = \frac{(A_t + X_t) - F_t}{C_t} * 100$$

where

- A_t is Actual net generation in MW,
- X_t is curtailment in MW due to transmission congestion or other reasons,
- F_t is forecast in MW,
- C_t is the available capacity in MW, and

- t is a time block.

Based on the above discussion, the reserves are calculated for each of the base cases and the cases with increased VREs. The reserve requirement is provided in the tables below:

Table 8-1: Regulating Reserves Requirement

	Load Forecast [MW]	Reserve (load) [MW]	Wind Forecast [MW]	Reserve (wind) [MW]	Solar PV forecast [MW]	Reserve (Solar) [MW]	Total Reserves [MW]
Summer Peak	26,045	±806	1,331	±133	315	±33	±972
Summer Off-Peak	21,455	±664	900	±90	150	±16	±770
Winter Peak	14,427	±446	432	±43	0	±0	±489
Winter Off-Peak	7,702	±238	178	±18	0	±0	±256

Table 8-2: Regulating Reserves Requirement with increased VRE integration

	Load Forecast [MW]	Reserve (load) [MW]	Wind Forecast [MW]	Reserve (wind) [MW]	Solar PV forecast [MW]	Reserve (Solar) [MW]	Total Reserves [MW]
Summer Peak	26,045	±806	2,052	±228	1,915	±213	±1247
Summer Off-Peak	21,455	±664	1,386	±154	1,150	±129	±947
Winter Peak	14,427	±446	1,032	±115	1,510	±168	±729
Winter Off-Peak	7,702	±238	592	±66	1,110	±123	±427

It is worth noting that the reserve requirement is not constant but depends on the load demand and VRE generation. Although VRE forecast has more error in real-time but here we have used the allowable margin from the grid code for the reserve calculations. The requirement of reserves will increase with the integration of VREs to deal with the power imbalances. To restrict the reserve requirement, more operating procedures need to be placed on VRE power plants that include better forecast or constraints functions that are explained in coming section.

8.2 Following Reserves

Following Reserve are the tertiary reserves needed to accommodate the variability and uncertainty that occur during normal conditions with the variation of VRE generation and load power. They include resources that can be activated within 30 minutes to a few hours. Fast-start natural gas power plants is an example of tertiary reserve sources that have has quick starting time and high ramp rate. The tertiary reserve requirement of 1000 MW can realize the requirement of following reserves.

8.3 Frequency control support from Wind Power Plants

The increasing integration of VREs, especially wind power into the grid will increase variability and uncertainty in electricity generation and will require an increased secondary reserve to compensate the power imbalance arising due to forecast error. Error in the wind power forecast deviate the frequency from its limit. Secondary reserves are always required to cope with these imbalances to ensure secure operation of power system.

Wind power plants are currently exempted from providing frequency support services; however, the increasing integration in future will require support from them such as conventional power plants. Energinet.dk, Danish system operator, have imposed certain regulating and constraint functions that are subjected to the conditions of the grid and wind[2]. This is to ensure that the various regulating and constraint functions do not interfere with each other. To deal with increasing integration of VREs, the following regulation can be implemented on VREs especially wind power plants for secure power system operation.

System protection

During overloading in the grid, system protection function regulates the active power from WPP to an acceptable level. This regulating function contributes to avoid system collapse in case of any unforeseen incidents. The down regulation in wind power starts when system protection signal is activated and continues till the termination of external signal. It must be possible to set up at least five different set points for the WPP and if require to change the set point, it must be done not later than 10 seconds after receiving instructions. The power output in system protection must not differ by more than ±2% of the set point value. The system protection regulation is shown in the Figure 8-1.

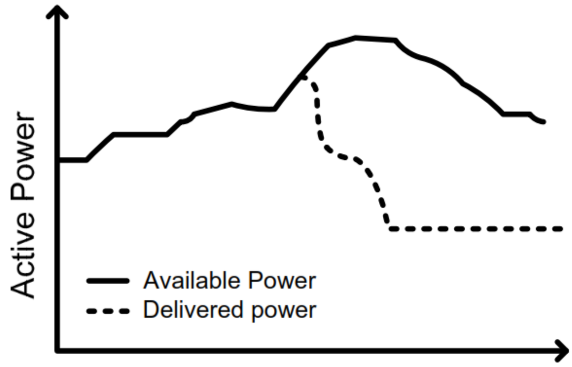

Figure 8-1: System Protection

Frequency Control

The automatic frequency regulation shall change the output power of the WPP to restore the frequency with an accuracy of ±50 mHz in case of deviation. The frequency control function from the WPP is shown in Figure 8-2. The frequencies between $f_2 - f_3$ form a dead band, whereas the WPP shall provide the primary control with Droop 1 if frequency is in between $f_1 - f_2$ and with Droop 2 if in between $f_3 - f_4$. The critical frequency control is supplied with Droop 3 and Droop 4 for frequency in between $f_4 - f_6$.

DELTA set aside reserves and is used to stabilize the system frequency, if frequency drops from point f_2. If frequency rises from f_3, the active power from the WPP is regulated downward. The WPP shouldn't up regulate its active power output if frequency reaches to

2 Eltra/Elkraft, "Regulation TF 3.2.5, Wind turbines connected to grids with voltages above 100 kV," Energinet.dk, Denmark, 2004

point f_5, until the grid frequency reduces than f_7. The shutting down of individual wind turbine is also allowed in case it is needed to down regulate the active power below P_{min}. The frequency set points can be changed not later than 10 seconds after receiving order signal. The accuracy of the power output must not deviate by more than ±2% of the set point value. For frequency control, the following frequency values are suggested for Figure 6-2 with Droop1, Droop2 of 4% and Droop3 and Droop4 of 6% and 5% respectively.

f_1 49.8 Hz
f_2 49.95 Hz
f_3 50.05 Hz
f_4 50.3 Hz
f_5 51 Hz
f_6 51.5 Hz

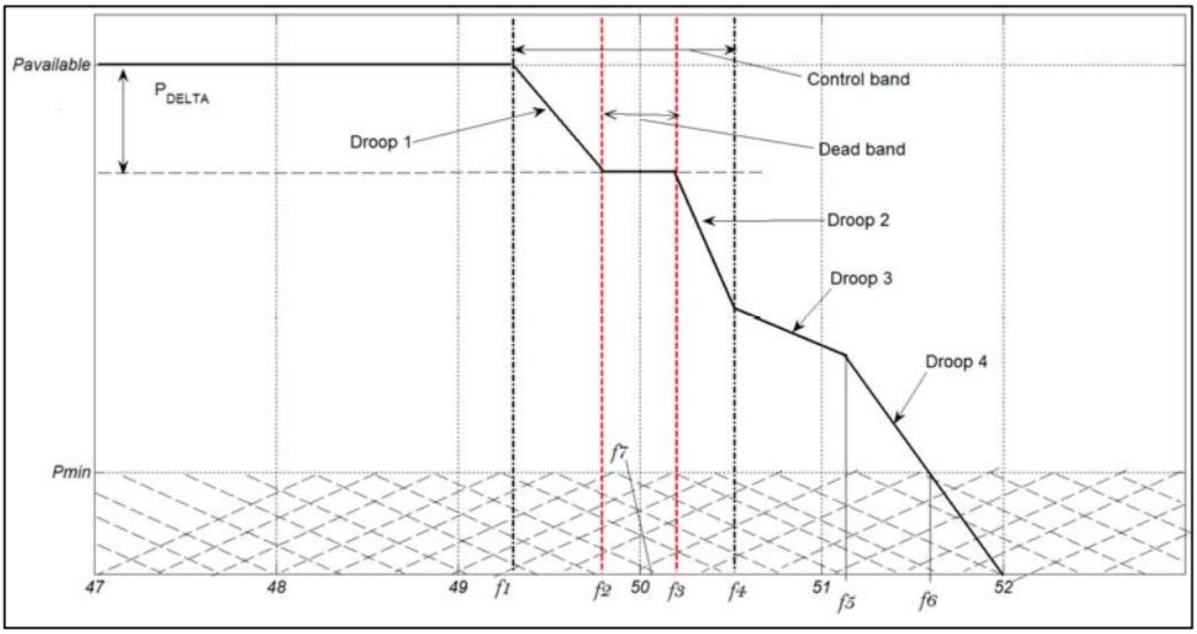

Figure 8-2: Frequency Control for WPPs

Constraint functions

The constraint functions are the auxiliary active power control functions that are used to avoid imbalances or overloading of electricity network during faults or other unpredictable events. The WPP must be equipped with the following constraint functions, i.e., power gradient constraint, absolute gradient constraint and delta production constraint. These constraint functions are described below:

Power gradient constraint

This constraint function limits the rate in wind turbine output power with respect to wind speed changes, as the conventional power plants might not be able to change their output as fast as the wind speed is changing. The settings for the power gradient constraint are provided by the system operator. Power gradient constraint function is shown in Figure 8-3.

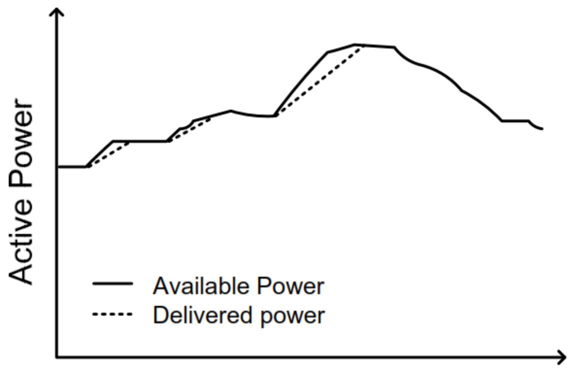

Figure 8-3: Power gradient constraint

Absolute production constraint

This regulating constraint limits the current power production of a WPP to random set MW value, when available power is in range of 20% to 100% of rated power. The maximum allowable deviation is ±0.5% of rated power at connection point. This regulating function shall not overload the grid. Absolute production constraint function is shown in Figure 8-4.

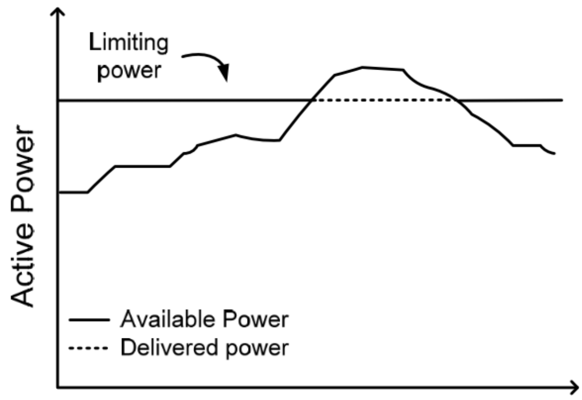

Figure 8-4: Absolute production constraint

Delta production constraint

This constraint function limits the current power production of a WPP by a fixed amount in proportion to the available power, thereby setting aside reserve for handling critical power requirement. Delta production constraint function can take part in frequency control. It reduces the power fluctuations due to high wind thus reducing the need of spinning reserves. Delta production constraint function is exemplified in Figure 8-5.

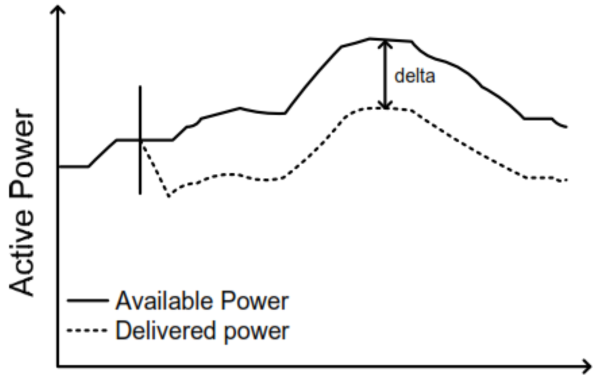

Figure 8-5: Delta production constraint

If a change in the set points for the above constraint functions is obliged, it shall commence within two seconds and completed not later than 30 seconds after receiving an order signal from the system operator. The power output must not deviate by more than ±2% of the set point value or by ±0.5% of the rated power, depending on which provides the highest tolerance.

8.4 Section Recommendations

This section provides the normal regulating reserves to deal with the power imbalances during normal operating conditions. The study considers the allowable margin of forecast error for load demand and VRE forecast for the calculation of required reserve power. During present conditions, ±972 MW of reserve power are needed for secure power system operations in the case of summer peak and ±256 MW of reserve power during winter off-peak. However, with the integration of 2500 MW solar and 1000 MW of the wind, the reserve power requirement will increase to ±1247 MW in summer peak and to ±427 MW in winter off-peak. The system needs reserve power for secondary control purpose and to minimize the regulating burden, only the reserve power required for N-1 contingency is considered. The same is also considered for Tertiary reserve power requirement.

The section has also discussed different control techniques that can enable WPPs to participate in frequency control services during different operating conditions. However, the large-scale integration of wind power in future may also requires services like primary and secondary balancing control from the WPP on continuous basis. The fast ramp rate need for the balancing response is not a technical threshold for WPP to participate in frequency control services. Reserves can be set aside from hour-ahead forecast wind power forecast or operating in a delta mode, to enable the WPPs to participate in primary and as well as in secondary control purposes. But, the variability of wind power with a limited predictability hurdles the full-time availability of reserves. However, less tight standards for WPPs may be defined in the future to have a certain capacity at a certain availability rate.

Wind power being cheapest source of producing electricity receives a dispatch priority and the most profitable strategy for a WPP is to produce at maximal capacity. Keeping wind power as an upward regulating reserving is expensive as the WPP has to produce continuously under maximal capacity. The upward regulating reserve imposes a reservation cost, depending on the lost revenues of electricity and is determined by the electricity price that could have been sold otherwise. However, the transmission constraints in the south and increasing integration of cheap generation from coal fired power plants require certain regulation from WPPs in order to accommodate large scale integration of WPP in the south region.

9 Policy Recommendations

- Operating reserves must be sufficient to maintain reliable operation of the power system under all credible contingencies. This includes contingencies such as the loss of a generating unit, transmission line, or substation.
    - Generation outages: If a power plant goes offline unexpectedly, NTDC must have enough operating reserve available to quickly replace the lost generation and maintain the balance between supply and demand.
    - Transmission outages: If a transmission line goes offline unexpectedly, NTDC must have enough operating reserve available to reroute power around the outage and maintain reliable service to customers.
    - Load spikes: If demand for electricity spikes unexpectedly, NTDC must have enough operating reserve available to quickly increase generation to meet the increased demand.
- Operating reserves must be able to respond quickly to changes in load and generation. This is especially important in systems with high levels of variable renewable energy (VRE) generation, such as wind and solar. The quantum of reserves during normal operations shall also take in account:
    - Forecasted load: This is the expected demand for electricity over the next 24 hours.
    - Forecasted generation: This is the expected output of all generation resources, including conventional power plants and renewable energy sources.
    - System conditions: This includes factors such as the availability of transmission lines and the status of maintenance outages.
- NTDC operating reserve policy need to be regularly reviewed and updated to ensure that it is aligned with the evolving needs of the power grid by accounting need for the increasing penetration of renewable energy generation and load demand. The requirements need to be adjusted seasonally to account for changes in load and generation patterns. The reserves are categorized as:
    - Normal operating reserves are used to maintain the balance between generation and demand on a real-time basis. It is typically provided by generators that can quickly adjust their output, to counteract forecast error in load demand and VRE forecast.
    - Contingency reserves are used to respond to unexpected events, such as the loss of a generator or transmission line. It is typically provided by generators that can start up and ramp up their output quickly.
- NTDC's operating reserve policy is based on a risk-based approach, meaning that the amount of operating reserve required is determined based on the likelihood and severity of potential unexpected events. NTDC also considers the variability and uncertainty of renewable energy generation when determining operating reserve requirements. The reserves are categorized as:
    - Spinning reserve is generation that is already online and synchronized to the grid. Spinning reserve can be deployed very quickly to respond to unexpected events. Primary and Secondary reserves are kept as spinning reserves.

  - Non-spinning reserve is generation that is not currently online, but can be brought online within a certain period of time. Tertiary reserves are kept as non-spinning reserves.
- NTDC requires all generators to provide a certain amount of spinning in proportion to their total capacity for primary and secondary control and make themselves available for providing non-spinning reserves as tertiary control. NTDC Shall develop dynamic operating reserve requirements that will take into account factors such as the real-time forecast of load and generation, as well as the operating status of the power system. This would help to ensure that there is always enough operating reserve available to meet the needs of the system.
- Primary Reserves:
  - The quantum of reserves required (spinning) should be calculated based on a risk assessment. The risk assessment should consider factors such as the size and complexity of the power system, the level of VRE generation, and the historical frequency and severity of disturbances.
  - The primary reserve requirement shall be shared between the control areas within the synchronous power system. The share of primary reserves shall depend on the load demand of the control area.
  - Power plants shall start activating primary reserves when frequency exceeds the dead band and achieve its full response within 30 seconds. The quantum of Primary reserves activate by the power plants shall depend on the frequency variation from its nominal level and the governor droop settings, and the response shall persist until the system frequency restores.
  - The reserves need to be distributed among all major power plants depending on their capability of providing primary reserves with frequency regulation of 6133 MW/Hz. The power plants contributing to primary response shall operate at least 7-8% less than their maximum operating point.
  - Power plants operating under speed governor response have to maintain their dead-band at 0.05 Hz as per grid code requirement
- Secondary Reserves
  - The quantum of operating reserves (spinning) required should be calculated based on a risk assessment. The risk assessment should consider factors such as the size and complexity of the power system, the level of VRE generation, and the historical frequency and severity of disturbances.
  - Secondary reserves shall start to activate within 1 minute of contingency event and achieve its output within 20 minutes for maximum contingency. For contingency less than the maximum level, the secondary control shall achieve its output accordingly.
  - Secondary control action shall restore frequency and primary reserves, and the power exchange to its schedule.
  - Secondary reserve shall be maintained on generating units with fast ramp rates that can activate the secondary reserve within the required time frame.

  - Secondary control action will be activated from the control area where contingency occur.
  - Operators should have the authority to dispatch operating reserves as needed to maintain reliable operation of the power system.
- Tertiary Reserves
  - The quantum of operating reserves (non-spinning) required should be calculated based on a risk assessment. The risk assessment should consider factors such as the size and complexity of the power system, the level of VRE generation, and the historical frequency and severity of disturbances.
  - Coordinate with neighbouring grid operators to share operating reserves to reduce the overall cost of operating reserves and improve the reliability of the power grid.
- Procure fast ramping reserves and synthetic inertia from BESS to support the integration of renewable energy resources, such as solar and wind, that is changing the way that power systems are operate.
- Procure fast ramping reserves and synthetic inertia from BESS support for secure operation of power system in winter season.

By implementing these policy recommendations, grid operators can help to ensure the reliability and affordability of the electric grid in the years to come.