CENTRAL ELECTRICITY REGULATORY COMMISSION
New Delhi

Coram:

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File No. L-1/18/2010-CERC Date: 13th April, 2018

In the matter of

Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations (5th Amendment), 2017

Statement of Reasons

1. Introduction:

1.1. The Commission vide notification dated 9th December 2016 issued the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fifth Amendment) Regulations, 2016 along with Explanatory Memorandum seeking comments/ suggestions/ observations from the stakeholders/public.

1.2. Comments were received from 19 stakeholders, organizations, and individuals, etc., which included State Power utilities, Central Electricity Authority (CEA), Power System Operation Corporation (POSOCO), Inter-state transmission licensees, generating companies including associations. Thereafter, the Commission conducted public hearing on 28.2.2017. Nine (09) organizations /individuals made oral submissions or presentations during the public hearing. List of stakeholders who submitted written comments and who made oral submissions/power point presentation during the public hearing is given at Appendix-I &Appendix-II respectively. The detailed comments are available on CERC website at www.cercind.gov.in. After due considerations of the comments/suggestions/objections received, the

Commission vide notification dated 12.4.2017 notified the Fifth Amendment to the IEGC Regulations.

1.3. The amendments proposed in the draft regulations, deliberation on the comments/suggestions offered by the stakeholders, statutory bodies and individuals, etc., on the proposed amendments and the reasons for decisions of the Commission are given in the succeeding paragraphs. While an attempt has been made to consider all the comments/suggestions received, the names of all the stakeholders may not appear in the deliberations. However, the names of all the stakeholders are enclosed as Appendix-I & Appendix-II.

2. Amendment of Regulation 2 of Principal Regulations

2.1. The definition of "Spinning Reserves" was proposed to be substituted in Regulation 2. (1) (sss) as under:-

"The Capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are synchronized to the grid and able to effect the change in active power."

2.2. **Comments received:**

2.2.1. **Sterlite Power Transmission Limited (SPTL)** has suggested following modification in the definition of Spinning Reserves (in bold):

"The Capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units **& BESS (Battery Energy Storage System) located at both the transmission line or at the generating stations**, which are synchronized to the grid and able to effect the change in active power."

2.2.2. SPTL has given the following rationale to the above submission:

a) As this amendment is focused on inclusion of spinning reserves along with the ancillary services for frequency regulation, hence spinning reserves should also be included and reflected along with the other eligible participants (i.e. Un-requisitioned Surplus of Inter State Generating Stations) in CERC ASOR, 2015.
b) BESS (Battery Energy Storage System) has analogy with both Generation & Transmission as per Electricity Act, 2003. BESS can be a part of transmission line whose capacity is monitored and operated by System Operator.
c) In this amendment both the Open Cycle Gas Turbines & Combined Cycle Gas Stations are included along with coal/lignite based thermal generation. Knowing the fact that Plant Load Factor of all the eligible Gas based Inter State Generating Stations under Ancillary Services Operations is less than 30 %, the co-location of BESS in those Gas based plants should also be taken into consideration.

2.2.3. Shri Vijay Menghani has submitted that the proposed definition may be modified to indicate clearly that it should be on line and within expected operational time. It is suggested that *"within 10 minutes of a dispatch instruction by the system operator "*may be appended at end of the clause. This is proposed as per prevailing regulations in other countries.

2.2.4. POSOCO has submitted that, the term 'unused' may be prefixed to 'capacity'. Further considering that Ancillary Services is many a times used to trigger units under Reserve Shut Down, similar definition of 'non-spinning reserves' may be added as under:

"***Non-spinning reserves:*** *The capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are not synchronized to the grid and are under reserve shut down (at the* *instant of invoking into operation) based on system requirement or system operator's direction."*

2.2.5. Neyveli Lignite Corporation Limited (NLC Ltd.) has submitted as under:

(a) Generally Spinning Reserve will be utilized during frequency drop in the grid caused by either generation loss or sudden increase in demand. System Operators will try to stabilize frequency at rated value by giving instruction to Spinning Reserve Providers to increase the generation (Active Power).

(b) The amendment is not specific whether the Spinning Reserve Providers have to respond for increase in Generation during frequency drop or have to respond in both directions (increase & decrease) for frequency variation. If it is in both directions, the change in active power shall be restricted between installed capacity and Technical Minimum of Generators.

2.2.6. CEA has submitted that in place of definition of spinning reserves, the definitions of Primary, Secondary and Tertiary Reserve/Control may be provided. Reasons for the same are as under:

(a) It seems that spinning reserves includes Secondary Control Reserve and partially Tertiary Control Reserve. Therefore, to avoid any confusion, definition of "Spinning Reserves" may be omitted and definitions of primary, Secondary and tertiary Reserve/Control may be defined in these Regulations and methodology along with time and duration of reserves required to achieve these responses may be provided in the Regulations.

(b) The report of the committee on Spinning Reserves constituted by CERC has provided the followings:

Reserve	Start	Full availability	End
Primary reserve	Immediate	< 30 s	>15 min
Secondary Control reserve	> 30 s	<15min	As long as required or till replaced by Tertiary Reserves
Tertiary control reserve		Usually > 15 min to Hours	

(c) Accordingly, the framework for commercial settlement may also be devised for Primary, Secondary and Tertiary Control.

2.3. **Analysis and Decision**

2.3.1. The definition of spinning reserve specifies the word “devices” which is inclusive in nature and wide enough to include devices such as energy storage system etc., under the ambit of spinning reserves. As such, it is not necessary to list all such devices in the definition. However, a list of such devices if deemed fit would be provided in the "Detailed Procedure for implementation of Spinning Reserve" to be approved by the Commission.

2.3.2. The POSOCO has suggested that "capacity" should be preceded by word "unused". It needs to be appreciated that the capacity under spinning reserve is to be identified by POSOCO as per the report of the "Committee on Spinning Reserve", and the capacity identified as spinning reserve cannot be said to be not in use. As such, we are not inclined to accept the POSOCO's suggestion in this regard.

2.3.3. The time frame in which the capacity under spinning reserve would be required to give response for frequency stabilization could be decided by POSOCO in due consideration of ramp up rates of participating generators. Further, it is also a matter of detailing which would be a part of the "Detailed Procedure for implementation of Spinning Reserve.”

2.3.4. Similarly, comments of NLC regarding use of spinning reserve under frequency up/down conditions and decrease in generation restricted between installed capacity and technical Minimum of Generators is a matter to be considered in the detailed framework of Ancillary Services including Spinning Reserves and would be a part of the "Detailed Procedure for implementation of Spinning Reserve".

2.3.5. CEA has suggested to include the definition of primary, secondary and tertiary reserves. The same may be considered to be included in the "Detailed Procedure for implementation of Spinning Reserve".

2.3.6. Accordingly, the proposed definition as above is to be retained as it is except for that the word 'capacity' in the proposed regulation has been changed with the plural "capacities".

3. Regulation 2(2) of the Principle Regulations was proposed to be substituted as under:

"Words and expressions used in these regulations and not defined herein but defined in the Act or other relevant CERC Regulations shall have the meaning as assigned to them under the Act or relevant Regulations of the Commission"

3.1. **Comments received:**

(a) Shri Vijay Menghani has submitted that all definitions which are related to system operation should be in Grid code as it is parent or principal Regulation and if required consistency should be maintained by referring IEGC in the Ancillary Service Regulation or other Regulations.

3.2. **Analysis and Decision**

3.2.1 As explained in the explanatory memorandum, the modification was suggested to avoid amendment of IEGC every time for inclusion of new definitions under other CERC Regulations. The proposed clause conforms to the standard principle of legislation drafting and is accordingly retained.

4. Amendment of Part 1 of Principal Regulations-

4.1. **The following clause was proposed to be added at the end of Regulation 1.4 (v)**

"This section will also cover scheduling and despatch of power of ISGSs for operation of Ancillary Reserve Services, for utilization of Un-requisitioned surplus power and for operation of Spinning Reserves with the process of the flow of information between the Generating Stations, National Load Despatch Centre, Regional Load Despatch Centre, Power Exchanges, the State Load Despatch Centres and other concerned users."

4.2. **Comments received:**

No comment has been received on the proposed amendment.

4.3. **Analysis and Decision**

Since the proposed provisions delineate the scope of the Section 1 and no comment has been received, the proposed amendment has been retained in the Final Regulations.

5. Amendment of Part 2 of Principal Regulations- The amendments of Regulation 2.2.2 (i), 2.2.1 (m), , 2.3.2 (g), Regulation 2.4.2 (i) & (j) and introduction of 2.7.1 (f) were suggested to cover the new roles and responsibilities entrusted to various organisations i.e. NLDC, RLDCs, SLDCs and RPCs for operation of Ancillary Reserve Services, for utilization of Un-requisitioned power and for operation of Spinning Reserves Services.

5.1. **The Regulation 2.2.2 (i) was proposed to be replaced as under:**

"NLDC shall be the nodal agency for collective transactions and Ancillary Services including Spinning Reserves."

5.1.1. **Comments received:**

No comments have been received on the proposed amendment.

5.1.2. **Analysis and Decision**

In view of the fact that no comments have been received, the proposed amendment has been retained as it is.

5.1.3. **The following clause was proposed to be added as Regulation - 2.2.1(m*)***

"Coordination with ISGSs, Regional Load Dispatch Centers, State Load Dispatch Centers and Regional Power Committees for implementation of Ancillary services, prudent utilization of Un-requisitioned power, and identification and operation of Spinning Reserves at inter-State level as per Detailed Procedure and Regulations specified by the Commission."

5.1.4. **Comments received:**

POSOCO has submitted that the additions proposed in the draft amendment may be added as Regulation 2.2.2 (iii) instead of Regulation 2.2.1(m), considering that it is basically a reproduction from the National Load Despatch Centre Rules 2005, notified by Ministry of Power. Further Regulation 2.2.2 (iii) may be renumbered as Regulation 2.2.2 (iv).

5.1.5. **Analysis and Decision**

In line with the suggestions of POSOCO, the proposed amendment has been added as Regulation2.2.2 (iii) and Regulation2.2.2 (iii)has been renumbered as Regulation2.2.2 (iv).

6. Regulation 2.3.2 (g) was proposed to be replaced as under:

"Operation of Ancillary Services including Spinning Reserves."

6.1 **Comments received:**

No comment has been received on the proposed amendment.

6.2 **Analysis and Decision**

In view of the fact that no comment has been received, the proposed amendment has been retained as it is.

7. The following provisions were proposed to be added as Regulation 2.4.2 (i) & (j) :

"2.4.2 (i) – To perform the functions as mandated under the Central Electricity Regulatory Commission (Ancillary Services Operation) Regulations, 2015."

2.4.2 (j) -To maintain the account of energy transacted under Ancillary Services Operation including Spinning Reserves "

7.1 **Comments received:**

No comment has been received on the proposed amendment.

7.2 **Analysis and Decision**

In view of the fact that no comment has been received, the proposed amendment has been retained as it is.

8. The following new clause (f) was proposed to be added after Clause (e) of Regulation 2.7.1

"be responsible for the functions as mandated in the detailed procedures under Central Electricity Regulatory Commission (Ancillary Services Operation) Regulations, 2015."

8.1 **Comments received:**

8.1.1 WBERC has submitted that SLDC is also required to follow the State Grid Code and other regulations framed by SERCs and States may have their own Ancillary Services Regulations, WBERC has suggested to modify the proposed amendment as under:

"be responsible for the functions as mandated in the detailed procedures under Central Electricity Regulatory Commission (Ancillary Services Operation) Regulations, 2015 in absence of any Regulation framed by SERCs on Ancillary Services"

8.1.2 CEA has submitted that there is no sub-clause of clause-2.7.1 in Principal Regulations.

8.2 **Analysis and Decision**

In view of the fact that role specified for SLDC in detailed procedures under Central Electricity Regulatory Commission (Ancillary Services Operation) Regulations, 2015, is already covered under Regulation 5.3 of IEGC, the proposed amendment is not considered necessary and accordingly, has been dropped.

9. Amendment of Part 5 of Principal Regulations –

9.1 The following was proposed:

Regulation 5.2 (f): The words "All thermal generating units of 200 MW and above and all hydro units of 10 MW and above" shall be substituted with words "All Coal/lignite based thermal generating units of 200 MW and above, Open Cycle Gas Turbine/Combined Cycle generating stations having gas turbines of capacity more than 50 MW each and all hydro units of 25 MW and above".

In Regulation 5.2 (f) (i) (a) the words "Thermal generating units" shall be substituted with words "Coal/lignite based thermal generating units."

In Regulation 5.2 (f) (i) (b), the words and number "10 MW" shall be substituted with the words and number "25 MW".

9.2 **Comments received:**

Kerala State Electricity Board limited (KSEBL) has submitted consolidated comment on Regulation 5.2(f),5.2(i)(b) and addition of 5.2(f)(i)(c) as under:

(a) Regulation 5.2 (f) the proposed amendment to increase the rating of the hydro units for RGMO obligation from 10 MW to 25 MW is welcome.

(b) As mentioned in the explanatory memorandum itself, the age of the units and the present system of governor are also to be considered while implementing FGMO/RGMO. KSEBL has requested that hydro units of 15 years or more age and those which are planned for RMU in the next five years may also be exempted from RGMO obligation,

(c) In the case of hydro units of age more than 10 years, FGMO with manual intervention may be permitted till the units are taken for renovation.

9.3 **Analysis and Decision**

9.3.1 Regarding the request that hydro units of 15 years or more age and which are planned for RMU in the next five years be exempted from RGMO obligation, the Commission is of the view that such units shall resort to FGMO with manual intervention till their R&M. As such, the proposed amendments have been retained as it is.

10. The following clause was proposed to be added as Regulation 5.2 (f) (i) (c) –

"Open Cycle Gas Turbine/Combined Cycle generating stations having gas turbines of capacity more than 50 MW each: with effect from 01.04.2017"

10.1 **Comments received:**

10.1.1 NTPC has submitted that classical governor control system is in built by design in units of OCGT / CCGT stations. RGMO / FGMO with Manual Intervention (Ml) is technically feasible but will require suitable modification / retrofitting in the existing system with the help of the OEMs and will take time before it can be implemented. Accordingly, a suitable timeline may be allowed for implementation of RGMO/ FGMO with Manual Intervention (MI) in the OCGT/ CCGT stations.

10.2 **Analysis and Decision**

10.2.1 Considering the suggestions of NTPC, the Commission has decided to provide a period of six months for implementation of RGMO in Open Cycle Gas Turbine/Combined Cycle generating stations. Accordingly, the effective date has been changed to 01.10.2017 from 01.04.2017.

11. Regulation 5.2 (f)(ii) (a) was proposed to be substituted as follows:

"There should not be any reduction in generation in case of improvement in grid frequency below 50.05 Hz (for example, if grid frequency changes from 49.9 to 49.95 Hz, or from 50.00 to 50.04 Hz there shall not be any reduction in generation). For any fall in grid frequency, generation from the unit should increase as per generator droop upto a maximum of 5% of the generation subject to ceiling limit of 105% of the MCR of the unit having regard to machine capability".

11.1 **Comments received:**

11.1.1 SRPC has submitted that the Regulation should be replaced as under:

"There should not be any reduction of improvement in grid frequency below 50.05 Hz (for example, if grid frequency changes from 49.90 to 49.95 Hz there shall not be any reduction in generation). For any fall in grid frequency, generation from the unit should increase as per generator droop limited to 5% of the generation level before frequency fall, with ceiling limit of 105% of the MCR of the unit subject to machine capability."

SRPC has submitted that the suggested modification aims to bring more clarity with respect to extent of primary response required from ISGS by way of governor action.

Further, SRPC has submitted that, for Regulations 5.2 (f), (g), (h) and (i),with improved frequency profile and large scale RE Integration, FGMO can be considered in place of RGMO.

11.1.2 POSOCO has submitted that the clause may be reworded as:

*~~"There should not be any reduction in generation in case of improvement in grid frequencybelow 50.05 Hz (for example, if grid frequency changes from 49.9 to 49.95 Hz, or from50.00 to 50.04 Hz there shall not be any reduction in generation).~~ For any fall in grid frequency, generation from the unit should increase as per generator droop ~~uptoamaximumof~~*by at least ***5% of the ~~generation~~MCR****subject to ceiling limit of 105% of the MCR of the unit having regard to machine capability and also subject to the limitations for hydro stations".*

The rationale as per POSOCO is that that station schedule varies throughout the day and the operator cannot be expected to keep on calculating and changing the load limiter value to 5% of the current generation level.

Further in case of less declaration (less than Normative DC) due to any constraints, ensuring margins for Primary response may not be possible by RLDC. Hence, suitable modification in the proposed amendment may be carried out so that generators are obligated to ensure the margins in case of less declaration through appropriate margins in DC itself.

11.1.3 KSEBL has submitted that the proposed modification under Clause 5.2 (h) has restricted the schedule of generating units to ex-bus generation corresponding to 100% of the installed capacity. Further, it has been proposed that Valve Wide Open (VWO) operation of units shall not be allowed so that there is margin available in valve opening for providing primary response upto 5% of the generation level. KSEBL has requested that along with the proposed modification under 5.f (ii) following may also be added:

"The generators shall declare their availability faithfully considering the 5% margin RGMO response. In case RLDC / SLDC Suomotu reduces the schedule, the reason for such decision shall be communicated in writing to such generators and also to all stakeholders. The DC shall be revised accordingly and shall be taken for computation of availability by the RPCs/state agencies. Instances of such high declaration made by the generators shall be reviewed in the commercial subcommittee meetings and if the explanation of the generator is not accepted, such cases shall be dealt with as mis-declaration."

KSEBL has proposed the above addition since there has been no consensus in the RPC forum regarding this issue and generators are claiming more availability. KSBEL has further submitted that sometimes the generation schedule is more than the DC of the generator while RRAS is scheduled. The high declaration made by the generators is getting denied for the eligible beneficiaries and the same is getting scheduled for RRAS'.

11.1.4 Neyveli Lignite Corporation Ltd (NLC) has submitted with regard to RGMO as under:

"The Commission has given more clarity on RGMO action during rise in frequency within IEGC range 49.90 Hz to 50.05 Hz emphasizing with illustration that there should not be any reduction in generation for improvement in grid frequency below 50.05 Hz. To facilitate above action, the Deviation Settlement Mechanism (DSM) rate may be fixed at one value for ISGSs for the IEGC range of Grid Frequency (49.90Hz to 50.05Hz) synonymous to capping of DSM rate at Rs.3.03/Kwhr. for generators using Lignite / Indigenous Coal. Also, DSM rate may be made uniform to both the generator and the beneficiary, removing the cap for the generator. The Generators cannot exactly match the Actual Injection to the Generation Schedule issued by RLDC and the Actual Injection may be either above or below the Schedule. If the Actual Injection is above the schedule, there will be manual intervention to reduce the generation since DSM rate approaches and becomes zero value for the frequency at and above 50.05 Hz and improvement in frequency will be dampened. To avoid this and to be in line with RGMO action, above suggestion may be considered."

11.1.5 Shri Vijay Menghani has submitted that, it is not clear as to why there should not be any reduction in generation, when frequency is in the range of from 50.00 – 50.04 Hz. Shri Menghani has further submitted as under:-

(a) It is important that unnecessary fuel should not be burned even for a block in view of its economic and environmental effect. If the Commission decides that target frequency is 50 Hz, then over generation should be avoided. In recent pasts, the trend of frequency remaining above 50.05 Hz for about 16-20% is due to this relaxed condition where action both by generator and system operator under ancillary operation starts at 50.05 Hz.

(b) The governor operation (RGMO) in Indian context is different from industry standard FGMO. Therefore, a graphical representation explaining set point, droop and restricted mode should be given. The provision of RGMO as stipulated in IEGC 2010 was a temporary provision in view of then prevailing frequency profile and

UI vector and it needs to be and should be replaced with FGMO. Shri Meghani has referred to the following observations in the SOR to IEGC 2010:

> "Shri A. Velayutham has submitted that the tightening of frequency band from 49.2 – 50.3 Hz to 49.5 - 50.2 Hz is a welcome step in the right direction. However, it is necessary to further move very close to 50 Hz operation. Only then it may be possible to adopt full FGMO operation from present restricted FGMO operation. Full FGMO may improve System performance through better Primary Control. Variations in frequency can cause equipment, protection and control malfunction. Also it affects the quality of Industrial product. Internationally the frequency control through Secondary Control is between 20 and 200 mHz.(0.02-0.2Hz)."

(c) Shri Menghani has further referred to the following observations in the Statement of Reasons (SOR) to Amendment to IEGC, in 2012:

> "3.4 We feel that if the generator is unable to carry out the RGMO in its units, then it should provide grid support through FGMO.
>
> It is clarified that the provision is made in view of the difficulties faced by certain generating companies to modify the machines to make them capable of operating in RGMO automatically. The proposed revision intends to allow the generators to operate the units in FGMO with manual intervention till the machine is modified for RGMO operation. We are of the view that the proposed amendment should be retained.
>
> We are also conscious of the fact that ultimately machines have to be operated in FGMO for which the progressive narrowing down of frequency band will help."

Shri Menghani has suggested that in present grid condition with frequency remaining around 50 Hz for most of the time and in view of sufficient generating capacity available, FGMO should be implemented in place of RGMO which requires special configuration than industry standard of FGMO.

11.2 Analysis and Decision

11.2.1 POSOCO, SRPC and Sh. Vijay Menghani have advocated that it is time to move from RGMO to FGMO as the frequency band has stabilized. In this regard, Commission is of the view that it would be prudent to move from RGMO to FGMO after the stabilization of ancillary services including spinning reserves. The situation shall be reviewed after six months from the date of introduction of spinning reserves as a part of Ancillary services.

11.2.2 There is merit in the suggestion of the Sh. Menghani that the upper limit for no-action towards generation reduction till frequency reaches 50.05 Hz needs review. Accordingly, the proposed Regulation has been amended by replacing the words "50.05 Hz (for example, if grid frequency changes from 49.90 to 49.95 Hz, or from 49.95 Hz to 50.04 Hz, there shall not be any reduction in generation)" with the words " 50.00 Hz (for example, if grid frequency changes from 49.90 to 49.95 Hz, or from 49.95 Hz to 49.99 Hz , there shall not be any reduction in generation)".

11.2.3 POSOCO has suggested that the primary response desired from a unit should be limited to 5% of MCR in place of 5% of generation level at the time of frequency fall, as suggested in the proposed regulation. In this regard, it is to point out that primary response from the thermal units is limited by thermal reserves in the form of pressurized steam in boiler and main steam piping. As such, thermal units operating at part load/technical minimum may not be able to provide primary response to the tune of 5% of MCR due to lower thermal reserve. Accordingly, the maximum response desired from all the units, including hydro units to maintain parity, has been retained as 5% of generation level at the time of frequency fall.

11.2.4 NLC has sought to revise the DSM rate for the grid frequency range of 49.90 Hz to 50.05 Hz. The same may not be necessary in view of the proposed modification as stated in para 11.2.2 above. However, the suggestion of NLC is taken note of and may be considered at the time of review of DSM Regulations, if deemed necessary.

12. The following amendment was proposed in Regulation 5.2 (f) (iii):

words "Gas Turbine/Combined Cycle Power Plants" shall be deleted.

12.1 **Comments received:**

12.1.1 NTPC has submitted that classical governor control system is in-built by design in units of OCGT / CCGT stations. RGMO / FGMOwith Manual Intervention (MI) is technically feasible but will require suitable modification / retrofitting in the existing system with the help of the OEMs and will take time before it can be implemented. Accordingly, a suitable timeline may be allowed by Commission for implementation of RGMO/ FGMO with MI in the OCGT/ CCGT stations.

12.1.2 POSOCO has submitted that a note should be added in Regulation 5.2 (f) (iii) in respect of wind and solar projects. The draft CEA Technical Standards for Connectivity to the grid envisages solar and wind generators also to provide primary response. Suitable note may therefore be added to the above provisions in the IEGC so that there is no blanket waiver from primary response for wind and solar generators.

12.1.3 CEA has submitted that for clause 5.2 (f)(i)(c) and Clause 5.2 (f) (iii), all other generating units including the pondage upto 3 hours, Gas turbine/Combined Cycle Generating Stations having Gas Turbines of Capacity 50 MW or lower, wind and solar generators and Nuclear Power Stations shall be exempted from Regulations5.2 (f) ,5.2 (g), 5.2 (h) and 5.2(i) till the Commission reviews the situation. Further, Clause 5.2 (f)(iii) seeks to remove exemptions granted to all Gas Turbines, Combined Cycle Gas Turbine Stations. But, the exemptions for the Gas Turbines/Combined Cycle Gas Turbine Stations of capacity 50 MW and below would need to be provided in Clause 5.2 (f)(iii).

12.1.4 MPPMCL has submitted that, the capital cost of implementation of FGMO in generating units should be contributed from either Power System Development Fund (PSDF) or it should be borne by the generating companies MPPMCL has suggested that additional capital cost of implementation of FGMO in generating unit, if any, may not be allowed as pass through in tariff.

12.2 **Analysis and Decision**

12.2.1 NTPC's request for granting time for implementation of RGMO in Gas Turbine/Combined Cycle Power Plants has already been accepted. Regarding POSOCO's submission that wind and solar generators should not be granted blanket waiver from primary response, the Commission is aware of the fact that with increase in penetration of renewable energy generation in Indian Grid, the requirement of primary response becomes more important considering variability of generation from the renewable based generating stations. The Commission, in line with the recommendations of Committee on FGMO, may bring renewable generators and nuclear generators under the ambit of primary response after carrying out due deliberations and consultations with stakeholders. The suggestion of POSOCO shall be considered at appropriate time after gaining experience of operation of ancillary services including spinning reserves.

12.2.2 CEA has suggested that exemptions to the Gas Turbines/Combined Cycle Gas Turbine Stations of capacity 50 MW and below would need to be provided in Clause 5.2 (f)(iii). The Commission is of the view that the same is implied by the amended Regulation 5.2 (f)(i)(c) which only includes “Open Cycle Gas Turbines/Combined Cycle generating stations having gas turbines of capacity more than 50 MW each”, in the list of generators required to provide the primary response.

12.2.3 The suggestion of the MPPMCL that the capital cost of implementation of FGMO in generating units should be contributed from either Power System Development Fund (PSDF) or should be borne by the generating companies, is not reasonable. Governor system and governor action gives stability, security and strength to the grid which eventually helps beneficiaries in receiving the reliable and quality power without frequency fluctuations. As such, Governor system being integral part of the generating station, its cost should be factored in the tariff for supply of power from the generating stations.

13. Regulation 5.2 (h) was proposed to be amended as under:

(i) In Regulation 5.2 (h), the sentence,

"All thermal generating units of 200 MW and above and all hydro units of 10 MW and above operating at or up to 100% of their Maximum Continuous Rating (MCR) shall normally be capable of (and shall not in any way be prevented from) instantaneously picking up to 105% and 110% of their MCR, respectively, when the frequency falls suddenly.” shall be substituted with the following sentence:

"All coal/lignite based thermal generating unit s of 200 MW and above, Open Cycle Gas Turbine/Combined Cycle generating stations having gas turbines of capacity more than 50 MW each and all hydro units of

25 MW and above operating at or up to 100% of t heir Maximum Continuous Rating (MCR) shall have the capability of (and shall not in any way be prevented from) instantaneously picking up to 105%, 105% and 110% of their MCR, respectively, when the frequency falls suddenly."

ii) Following para may be added at the end of clause 5.2 (h):
"For the purpose of ensuring sustainable primary response, RLDCs/SLDCs shall not schedule the generating units beyond ex-bus generation corresponding to 100% of the Installed capacity. Further, Valve Wide Open (VWO) operation of units is not allowed so that there is margin available in valve opening for providing primary response upto 5% of the generation level. In case of gas/Liquid fuel based units also, adequate margins while scheduling should be kept by RLDCs/SLDCs in due consideration of prevailing ambient conditions of temperature and pressure viz. a viz. sit e ambient conditions on which installed capacity of these unit s have been specified. Provided that the VWO margin shall not be used by RLDC to schedule Ancillary Services."

13.1 Comments received:

13.1.1 SRPC has submitted as follows:

(a) Instead of proposed addition at the end of Clause 5.2 (h),following para may be added:
"For the purpose of ensuring sustainable primary response, RLDCs/SLDCs shall schedule the applicable generating units upto 95% of DC (Keeping 5% margin for primary response). Generators would faithfully state DC (inclusive of RGMO response and also with due consideration of prevailing ambient conditions of temperature and pressure viz. a viz. site ambient conditions on which installed capacity of these units have been specified.) Further, Valve wide Open (VWO) operation of units is

not allowed so that there is margin available in valve opening for providing primary response upto 5% of the generation level. Provided that the VWO margin shall not be used by RLDC to schedule in Ancillary Services (including reserves). RLDC shall inform the Commission once in 6 months about the Governor Response (whose scheduling is being undertaken by RLDC) for all the instances which meet the criteria of providing governor response".

Reasons submitted by SRPC to the above:-There have been number of deliberations on DC:

- Generators state that DC is their prerogative. It is upto the RLDC to restrict the schedules to ensure RGMO response.
- Beneficiary state that generators should declare DC which can be scheduled (RGMO component need not be declared)

(b) SRPC has submitted that with this approach it would be binding on the generators to declare DC inclusive of RGMO response. RLDC would have a clear methodology of scheduling only upto 95% of DC. As an alternative, Commission may decide that DC shall be exclusive of RGMO response as suggested by beneficiaries and in that case RLDC shall schedule upto DC. In both the cases Governor response needs to be monitored and appropriately dealt with in case of inadequate response.

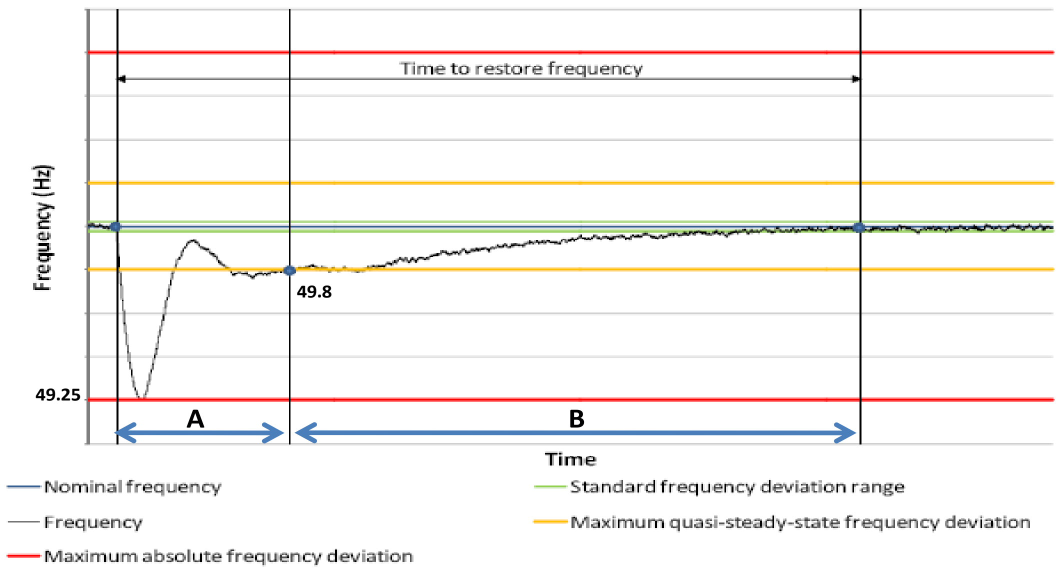
13.1.2 NTPC has submitted following

(a) With respect to Primary Reserve Requirement in India:

Primary control (governor control) is used for frequency stabilization after a large disturbance which operates in seconds (proportional control), the Secondary control restores the primary reserves and frequency to target frequency (50 Hz) and operates in minutes (Integral control) and the tertiary control restores secondary reserves and operates in tens of minutes. For keeping primary reserves, it is necessary to define “event” / “disturbance” and also the quasi steady state frequency by which entire reserves should be harnessed. In the absence of secondary control in Indian grid, target frequency is also not fixed. However considering the target frequency of 50 Hz and a quasi-steady state frequency of 49.8 Hz (Δf=-0.2 Hz) due to outage of largest power station in the country as a credible contingency, following example can be considered for keeping primary reserve.

- Power demand and corresponding generation considered as 150,000 MW at 50Hz at the time of disturbance.
- "Disturbance" / "Event": Outage of largest power station or as per NERC / WECC guideline 3% of Generation i.e 4,500 MW is considered as event of credible contingency.
- Load damping** of 4% and
- Governor Droop Setting*** of 5% is assumed.

Parameter	Unit	Peak Load
Demand	**MW**	**150,000**
Generation	**MW**	**150,000**
"Disturbance" Generation outage, ΔP_G	MW	**4500**
Post trip Generation, P_G' (=$P_G - \Delta P_G$)	MW	145,500
Capacity of Machines on Governor control to deliver primary response.	**MW**	**40,000**
D (Load Damping)**	**MW/Hz**	**6,000**
1/R (Governing)***	**MW/Hz**	**16,000**
AFRC, β = (D + 1/R)	**MW/Hz**	**22,000**
$\Delta f = \Delta P_G \div \beta$	**Hz**	**-0.20**
$f = f_N + \Delta f$	**Hz**	**49.80**



NTPC has submitted that from the above calculation for the present situation of Indian grid, the frequency decline can be arrested to -0.2 Hz (quasi Steady State Frequency at 49.8 Hz if nominal frequency is maintained at 50 Hz by Secondary Control) in case of outage of largest power station if Primary reserve or Governor control is ensured on units having total capacity of only approx. 40,000 MW out of in service (synchronised to Grid) Thermal generation of approx. 150,000 MW The maximum absolute frequency deviation can also be arrested above 49.25 Hz which is above the acceptable range of UCTE. NTPC has submitted as under:-

(i) So, putting RGMO / FGMO with MI in almost all machines as proposed in the IEGC, even in the Gas Turbines, is a luxury attracting in-fructuous/ avoidable expenditure for making the old systems RGMO compliant.

(ii) Even withholding cheaper power of Pit head stations like Sipat, Singrauli, Korba etc. for the purpose of primary response is also against the theory of economic despatch.

(iii) Primary Reserve margin may be kept in those machines whose variable cost is moderately high and operating at part load. System operator should carry out such study and earmark those 40,000 MW plus machines which must be operated on Governor control (not RGMO) and support grid security in the event of disturbances. The prerequisite to the above is to keep frequency within the governor dead band of target frequency of 50 Hz by Secondary Control, which can be achieved through implementation of AGC mechanism.

(b) Till that time, the way forward as suggested by NTPC is as follows:

(i) The stipulations in IEGC regarding Governor Control be kept in abeyance, as the same remained suspended from 2004 to 2010, to be re-introduced in its uncorrupted form as "Governor Control" at a future point in time after introduction of secondary control and frequency constancy is achieved.

(ii) All the unconventional and non-standard changes incorporated in the Governor Control logic by several generators to meet the stipulations of RGMO and FGMO be discarded. Further, the locally coined terms of FGMO and RGMO be discarded from use and be aligned with the internationally accepted terminology of "Governor Control". Uncorrupted Governor Control in all the machines bere-established which has also been recommended by M/s Solvina International.

(iii) Secondary Control in time bound manner be introduced, duly supplemented by Tertiary Control.

(iv) Once the Secondary Control and Tertiary Control are successfully introduced, frequency at a constant value could be controlled and Inter-Regional exchanges could be maintained close to schedule for more than 99% of the time. The only deviations remaining to be taken care of will then be the large frequency deviation events (like a large unit tripping, loss of large load area etc).

(v) After completion of the above, Primary Control should be introduced. All generating units with the exclusion of spilling hydro, waste heat recovery units and RE sources must then be operated on Governor Control in its purest form. Since carrying reserves for Primary Control have not commenced, the Governor control will work only in the direction of reducing generation for large frequency rise events. All machines on Governor Control must provide this service.

(vi) It will then be the proper time to introduce Primary Control Reserves. The minimum required quantum of Primary Control reserve must now be carried on the committed generating units in highest incremental cost bracket. Large pondage hydro units having no risk of spilling, if committed in service will also be an ideal choice. This quantum required can be worked out easily as shown in the example. Each of these machines may carry 10-20% of its capacity as Governor Reserve. How these machines can be made to deliver this reserve in under 1 minute will also have to be looked into.

(vii) In the above sequence, a full-fledged frequency/interchange control system, at par with any other electricity system in the world can be achieved.

(c) Cost of Carrying 5% Primary Reserves in all machines

NTPC has suggested that the cost of carrying the reserves needs to be considered while proposing that the units will not be scheduled by RLDC/SLDC beyond ex-bus generation corresponding to 100% of the Installed Capacity. The excess capacity available in each generating unit, including the zero cost hydro units, by their overload capability or otherwise, will remain unused for most of the time. The Electricity Act, 2003 requires the Regulatory Commissions to make recommendations to bring about efficiency and economy in the industry. NTPC has explained the position with the help of following example:-

Let us examine the cost of carrying 5% Primary Control Reserve, on all machines in the system, uniformly.

Let us imagine our 120,000MW system carrying a Primary Control Reserve Capacity of 6,000MW (5% uniformly on all machines). Let us also assume for simplicity 50% of the entire capacity is low cost energy (Pit Head Stations, Hydro etc) having an average variable cost of Rs.1.25/kWh and the other 50% capacity has an average variable cost of Rs.3.25/kWh. Our stipulation of carrying 5% capacity reserve uniformly on all machines, translates to 3,000MW of the low variable cost capacity and 3,000 MW of high variable cost capacity remaining unused, for near 100% time. Obviously, to meet the 3,000MW load in the system vacated by the first 3,000MW capacity being in service presently will have to be served for 100% time from the latter high cost capacity units.

By dispatching the low cost capacity fully and carrying the 3,000 MW additional reserve capacity on the higher variable cost units (10% on 50% capacity of 60,000MW) we will be deploying 3,000 MW generation at Rs 1.25/kWh while withdrawing the same quantum at Rs 3.25/kWh. The annual saving made would be Rs 5256 Crore in the system.

NTPC has suggested that the Commission may consider the disadvantages of restricting the scheduling to ex-bus generation corresponding to 100% installed capacity and withdraw the proposed amendments for this purpose.

Notwithstanding the above, in the event the Commission decides to implement the proposed draft Regulation 5.2(h), it will be required to revise the Operating Norms of generating stations. This is because, the Operating Norms have been earlier fixed based on actual performance achieved by Stations in the previous years. Such performance included the generation level and hence, the better operating norms achieved out of the excess capacity available beyond the Installed Capacity. Since this capacity will no more be available for despatch, it would lead to deterioration in performance norms of many of the Stations.

13.1.3 POSOCO has submitted that Installed capacity and MCR are defined at generator terminal, whereas RLDCs prepares schedule at the ex-bus of generator. Therefore in order to have clarity on the maximum power to be scheduled and power to be kept for primary response, ex-bus generation schedule ceiling corresponding to 100% of the Installed capacity less normative auxiliary consumption may be specified. Further, Hydro Generating Stations may be required to run till the overload capacity, at times, to avoid spillage of water and to manage peak load. Further, while deciding Normative Annual Plant Availability (NAPF) for hydro generating stations, the Commission has already taken into cognizance the overload capability. POSOCO has proposed that overflowing hydro generating stations may be excluded from the ambit of the proposed amendment. Considering the above, following changes have been suggested by POSOCO:

"For the purpose of ensuring sustainable primary response, ~~and RLDCs/SLDCs shallnot schedule the generating unit s beyond ex-bus generation corresponding to100% of the Installed capacity~~ISGS (excluding overflowing hydro generators)shall limit ex bus capability for the next day upto installed capacity less normative auxiliary consumption. Further, these stations should ensure that inreal time also, they do not intentionally exceed these values to get benefit, if any, under the Deviation Settlement Mechanism. The margins should be available only to take care of primary frequency response. Over-flowing hydro stations should keep a record of water inflows, reservoir levels, discharge through turbines and spillage and submit the same whenever requested by RLDCs/SLDCs."

13.1.4 JSW Energy Limited has submitted that, most of the Hydro Electric Plants are having Maximum Continuous Rating (MCR) as 110% of Installed Capacity. Therefore, such provision will lead to loss of about 10% of generation which is nothing but a national loss. Such restriction will have severe impact on the financial viability of hydro projects. In view of above, Run of River and Run of River with

Pondage Hydro Electric Plants may be excluded from aforesaid condition during the peak season.

13.1.5 WBERC has suggested that real life example with date is needed for further clarification on paragraph proposed to be added at the end of clause 5.2 (h)of IEGC.

13.1.6 CEA has submitted that this clause needs to be modified as under:

> "For the purpose of ensuring sustainable primary response, RLDCs/SLDCs shall not schedule the generating units beyond ex-bus generation corresponding to 100% of the Installed capacity. Further, Valve Wide Open (VWO) operation of units is not allowed so that there is margin available in valve opening for providing ………………………………………………
>
> Provided that Hydro Stations may be scheduled beyond exbus generation corresponding to 100% of installed capacity such that 5% overload capacity is still available to provide primary response.
>
> Provided further that Hydro stations shall normally be scheduled such that there is no spillage of water."

13.1.7 CEA has further submitted that CEA (Technical Standard for Connectivity to the Grid), Regulations 2007 notified on 21/02/2007 provides that all generating machines irrespective of capacity which are connected on or after the date on which these regulations became effective shall have electronically controlled governing system with approximate speed/ load characteristics to regulate frequency. As such, the Commission may consider not to give a blanket exemption for generating machines of capacity lower than the capacity suggested in the draft amendment as it would be in contravention of CEA's Connectivity Regulations. CEA has suggested that tobring clarity that hydro plants which are capable of providing 110% of the rated capacity in line with CEA Regulations should be scheduled optimally to exploit the availability of water and overload capacity in the Plants.

13.1.8 Shri Vijay Menghani has submitted as follows:

"suddenly" is a qualitative terms and to check performance of Frequency response, it should be defined in numerical terms of either Δf or $\Delta f/\Delta t$. This is required so that frequency response during normal load variation i.e as required under Regulation 5.2(ii) (a) and under this clause for condition during contingency can be quantified and monitored. Shri Vijay Menghani has submitted that the relaxation proposed for less than 25 MW is not under purview of CERC and it should be taken care in CEA grid standards. Sh. Menghani has further expressed his view that in place of regulatory exemption, specific old hydro generating stations may be exempted based due to non – feasibility in the following conditions:

(a) For hydro generation when water is available for more than 100% generation the condition of restricting generation upto 100% will result in water spillage and should not be applied. While procuring generating machines for hydro station, the developer for complying with CEA regulation has already invested in 110% capacity and beneficiaries are already paying for this, so not utilizing this margin when water is available will lead to un- economic operation. In specific grid like conditions when sufficient spinning reserve is not available in regional/national grid, system operator, can ask them to keep this margin available .But in high hydro season, this margin should not be maintained at the cost of spillage.

(b) Keeping 5% margin in all machines is uneconomic. System operator should calculate spinning reserve requirement and it can be done easily and this quantity be allocated based on merit order. It will be more economical if pit head stations are exempted from this provision. This is also as per international practice where small inefficient units which are on bar, are assigned this task.

(c) In view of past experience of almost 15 years that primary response is not coming through regulated entities, either existing provisions of Grid code should be implemented strictly or if necessary, some economic incentive needs to be provided for frequency response rather than keeping 5% margins on all machines unutlised. If due to non availability of secondary control (AGC), FGMO response is not forthcoming, the issue of AGC need to be taken up urgently and only after one year of experience, other options like schedule restrictions may be considered. While proposed draft regulation is not allowing scheduling beyond capacity corresponding to installed capacity (i.e Installed capacity – Auxiliary consumption) for this margin, it is not stated as to how generating company will be restrained from using this margin under deviation mechanism. If generator uses this for over generation (as 12% generation beyond schedule is permitted), at the time of grid requirement, this capacity would not be available to provide intended relief.

13.2 Analysis and Decision

13.2.1 The provision of restricting scheduling limited to ex-bus generation corresponding to 100% of Installed capacity(IC) along with non-operation with VWO has been envisaged for ensuring 5% primary response from the stations which have declared DC above 100% of IC less auxiliary energy consumption (AEC). This 5% primary response would come from the release of thermal reserve by opening of steam inlet valves with corresponding decrease in main steam pressure. As such, this increased generation would not be sustainable without increasing fuel firing. Now having provided the primary response, there is a existing provision of ramping back to the previous level of generation if the increased level of generation is not sustainable.

13.2.2 This provision of keeping primary reserve margin is not applicable to units which have declared DC less than the 100% of IC (less AEC) i.e. schedule of a unit which has declared DC corresponding to 90% of IC less AEC shall not be curtailed to 85% of IC for keeping primary reserve margin because the desired primary response (5% of 90% of IC i.e. 4.5% of IC) would come without increasing fuel firing by way of stored thermal reserves. Any instance of generation increase by increased fuel firing comes under the secondary response and not primary response. For hydro stations, the restriction of schedule is applicable only for lean inflow period. Here also, the schedule is to be restricted to 100% of IC less AEC only during peaking hours and not for remaining period during which remaining energy i.e. energy declared less energy produced during peaking hours, is being scheduled. During non-peaking hours, when the units are on part load, primary response would come automatically by governor action through release of stored water. As such, during non-peaking hours there is no need for curtailing the schedule. The above deliberation settles the issues raised by SRPC.

13.2.3 NTPC has submitted that keeping primary reserves in stations with aggregate installed capacity of 40,000 MW would be sufficient to contain the frequency to 49.80 Hz in case of generation loss of 4500 MW. With the assumptions of 5% droop i.e. primary response of 40% per Hz and load dampening of 4% per Hz, the load dampening would be to the tune of 1200 MW for 0.20 Hz frequency fall (with load being met to the tune of 1,50,000MW) and primary response would be to the tune of 3200 MW (40,000*0.40*0.20). In this regard, we have analyzed that the generation increase works out to 8% of the participating installed capacity putting more strain on participating stations in terms of fluctuations in operating parameters which may eventually lead to unit tripping or damage of costlier equipment. On the contrary, again consider the example of grid operating with installed capacity of 1,50,000 MW with the safe assumption that 75,000 MW capacity would be providing primary response with 5% droop limited to 5% of generation level. Now in such case, going by the provision of IEGC, for generation loss of 4500 MW, primary response would be to the tune of 3750 MW (5% of 75,000 MW) and difference would come through load dampening of 750 MW settling the new frequency at 49.875 MW i.e very close to the operating frequency band of 49.90 Hz to 50.05 Hz. In case, most of the generators provide primary response frequency would get restored very close to the 50 Hz. As such, considering the same, the primary response of 5% is being demanded from all the stations not-withstanding the cost repercussion as mentioned by NTPC. Further, regarding cost repercussion as mentioned by NTPC, it is pointed out that in percentage terms, the cost is not substantial for large Indian Grid. As such, this cost shall be borne by the beneficiaries for the purpose of grid security which ultimately is in the interest of the consumers as well as the nation at large. Further, with full RE penetration of solar and wind, only the thermal generating station having low energy charges would be in operation. As such exempting them from primary response would effectively mean that grid has no primary response.

13.2.4 POSOCO has suggested that in view of the fact that Installed capacity and MCR are defined at generator terminal, whereas RLDCs prepares schedule at the ex-bus of generators and therefore in order to have clarity on the maximum power to be scheduled and the power to be kept for primary response, ex-bus generation schedule ceiling corresponding to 100% of the Installed capacity less normative auxiliary consumption may be specified. In this regard, it is clarified that since actual auxiliary consumption would be known only after actual operation of machines, it is implied that schedule restriction has to be based on normative auxiliary consumption. Accordingly, the explicit mentioning of the word "normative" before auxiliary consumption is not required.

13.2.5 Number of stakeholders have submitted that restriction of schedule for keeping primary response margins should not be resorted to for hydro stations during high inflow season to avoid spillage. This suggestion has merit and therefore, has been accepted that during high inflow season to avoid spillage there shall be no restriction of schedule.

13.2.6 JSW Energy Limited has submitted that, most of the Hydro Electric Plants are having MaximumContinuous Rating (MCR) as 110% of Installed Capacity. Therefore, the proposed provision will lead to loss of about 10% of Generation which is a national loss. Such restriction will have severe impact on the financial viability of hydro projects. JSW has suggested that Run of River and Run of River with Pondage Hydro Electric Plants may be excluded from aforesaid condition during the peak season. In this regard, it is clarified that hydro stations are not debarred from giving DC corresponding to overload capacity. Further, the non-restriction of schedule to avoid spillage during high inflow season has been accepted at para 13.2.5 above. As such, this is not likely to put any financial burden on hydro stations.

13.2.7 Regarding CEA suggestion that Hydro Stations may be scheduled beyond ex-bus generation corresponding to 100% of installed capacity, so that 5% overload capacity is still available to provide primary response, it is clarified that a hydro station which has declared ex-bus DC corresponding to 110% (including overload) of MCR during lean season shall be scheduled to 100%, leaving 10% margin for primary response. The additional 5% i.e. difference between 10% overload capacity and 5% desired primary response has been kept, in view of the fact that most of the hydro generators do not like to stress their units beyond 103% to 107% of MCR. As such, it has been left to the generator to decide the extent of machine loading beyond 105% i.e. after providing the desired primary response of 5%. Accordingly, 5% response from Hydro station has been made mandatory and beyond 5%, it is optional subject to machine capability and commercial decision of the generator based on prevailing DSM rates. All such generations beyond 100% shall be treated as primary response under DSM.

13.2.8 We are of the view that declaration of capacity including overload margins is the prerogative of the generator. Generator based on its experience about the healthiness of the units is allowed to declare its declared capability based on machine and fuel/water availability. However, it was being observed that units which were scheduled beyond ex-bus capability corresponding to 100% of IC were not able to provide primary response as these units were operating on VWO mode leaving no margins for further valve opening by governor action during frequency decrease. As such, through the addition in Regulation 5.2 (h), of IEGC, RLDCs/SLDCs have been allowed not to schedule the units beyond ex-bus generation corresponding to 100% of installed capacity. However, for the purpose of calculation of PAF, DC declared by the generator is not to be reduced. This would ensure proper incentive for the generator for keeping units in readiness for providing much needed grid support in case of frequency excursion.

13.2.9 In view of the above deliberations, Regulation 5.2 (h) shall be amended as follows:

(a) The first sentence of Regulation 5.2(h) of Part 5 of the Principal Regulations, shall be substituted as under:

"All coal/lignite based thermal generating units of 200 MW and above, Open Cycle Gas Turbine/Combined Cycle generating stations having gas turbines of more than 50 MW each and all hydro units of 25 MW and above operating at or up to 100% of their Maximum Continuous Rating (MCR) shall have the capability of (and shall not in any way be prevented from) instantaneously picking up to 105%, 105% and 110% of their MCR, respectively, when the frequency falls suddenly.”

(b) The following shall be added at the end of Regulation 5.2 (h) of Part 5 of the Principal Regulations:

"For the purpose of ensuring primary response, RLDCs/SLDCs shall not schedule the generating station or unit(s) thereof beyond exbus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall ensure that there is margin available for providing Governor action as primary response. In case of gas/liquid fuel based units, suitable adjustment in Installed Capacity should be made by RLDCs/SLDCs for scheduling in due consideration of prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:

Provided that scheduling of hydro stations shall not be reduced during high inflow period in order to avoid spillage:

Provided further that the VWO margin shall not be used by RLDC to schedule Ancillary Services.”

The high inflow period shall be decided by respective RLDCs.

14. In order to ensure primary response from generators, the Commission deems it fit to include the followingnew proviso to be added at the end of Regulation 5.2 (g):

"Provided that periodic checkups by third party should be conducted at regular interval once in two years through independent agencies selected by POSOCO/SLDCs. The cost of such tests shall be recovered by the RLDCs or SLDCs from the

Generators. If deemed necessary by RLDCS/SLDCs, the test may be repeated/conducted more than once in two years."

15. Clause 3 of Regulation 6.5

15.1 Clauses (3), (4), (7) and (8) of Regulation 6.5 of the IEGC were proposed to be substituted as under:

"(3)By 1 PM every day, the ISGS shall advise the concerned RLDC, the station-wise ex-power plant MW and MWh capabilities foreseen for the day after the next day, i.e., from 0000 hrs to 2400 hrs of the day after the next day."

(4)The above information of the foreseen capabilities of the ISGS and the corresponding MW and MWh entitlements of each State, shall be compiled by the RLDC every day for the day after the next day, and advised to all beneficiaries by 3 PM. The SLDCs shall review it vis-à-vis their foreseen load pattern and their own generating capability including bilateral exchanges, if any, and advise the RLDC by 5 PM their tentative drawl schedule for each of the ISGS in which they have Shares, long-term and medium-term bilateral interchanges, approved short -term bilateral interchanges.

(7). By 7 PM each day, the RLDC shall convey:

(i) The ex-power plant "despatch schedule" to each of the ISGS, in MW for different time block, for the day after the next day. The summation of the ex-power plant drawal schedules advised by all the beneficiaries shall constitute the ex-power plant station-wise despatch schedule.

(ii) The tentative "net drawal schedule" to each regional entity, in MW for different time block, for the day after the next day next day. The summation of the station-wise ex-power plant drawal schedules from all ISGS and drawal from /injection to regional grid consequent to other long term access, medium term and short -term open access transactions, after deducting the transmission losses (estimated), shall constitute the regional entity-wise drawal schedule.

(i) ISGS wise Un-requisitioned surplus (URS) power to ISGS and SLDCs.

8(a) Original Beneficiaries of an ISGS will have first right to give requisition for the URS power of the ISGS. Such original beneficiaries shall advice RLDCs, through their SLDC, regarding quantum of power and time duration of such drawal out of declared URS of the ISGS, by 8 P.M. In case full URS of an ISGS is requisitioned by more than one original beneficiary, RLDC shall allocate URS proportionately based on the share of these original beneficiaries in the ISGS.

8(b) RLDCs to post the ISGS wise data of balance URS on its website by 9 P.M. after modifying the tentative net drawal schedule of the original beneficiaries after taking into account the URS requisitioned and associated transmission losses.

8(c) ISGS may sell the balance URS power left after completion of the process of requisition by other original beneficiaries of the plant, in the market. The original beneficiary shall communicate by 12 P.M about the quantum and duration of such URS power to ISGS to enable ISGS sell same in the market. If the original beneficiary fails to communicate to ISGS, then the ISGS shall be entitled to sell the URS power of the beneficiary in the market.

8(d) The URS which has been sold and scheduled by ISGS in the market (power exchange or through STOA) cannot be called back by the original beneficiary.

8(e) After sale in market as under 8(d) above, if any power still remains under URS, the same may be requisitioned by the beneficiaries of the station.

8(f) By 6 P.M, each day, RLDC shall convey ex-power power plant dispatch to each ISGS for the next day after incorporating sale in market.

8(g) Any change in drawals/foreseen capacities shall be communicated to RLDCs by 10 P.M of the day prior to day of scheduling."

15.2 The Commission had given following rationale while proposing said amendment:

"Tariff Policy dated 28.1.2016 has introduced certain provisions to utilize the URS of ISGSs as quoted below:

"Power stations are required to be available and ready to dispatch at all times. Notwithstanding any provision contained in the Power Purchase Agreement (PPA), in order to ensure better utilization of un-requisitioned generating capacity of generating stations, based on regulated tariff under Section 62 of the Electricity Act 2003, the procurer shall communicate, at least twenty four hours before 00.00 hours of the day when the power and quantum thereof is not requisitioned by it enabling the generating stations to sell the same in the market in consonance with laid down policy of Central Government in this regard. The developer and the procurers signing the PPA would share the gains realized from sale, if any, of such un-requisitioned power in market in the ratio of 50:50, if not already provided in the PPA. Such gain will be calculated as the difference between selling price of such power and fuel charge. It should, however, be ensured that such merchant sale does not result in adverse impact on the original beneficiary(ies) including in the form of higher average energy charge vis-à-vis the energy charge payable without the merchant sale. For the projects under section 63 of the Act, the methodology for such sale may be decided by the Appropriate Commission on mutually agreed terms between procurer and generator or unless already specified in the PPA."

In order to incorporate the above provisions necessary amendments were proposed in Regulation 6.5:

> "To meet the time line of the Tariff Policy i.e. ISGS shall have the communication regarding un-requisitioned power from the procurers at least 24 hours before 0.00 hours of the day of scheduling, it is being suggested that day ahead scheduling and despatch procedure shall be replaced with two day ahead scheduling. The time lines for each step of scheduling and despatch procedure are debatable subject to restriction that information of URS, which can be sold in the market, shall be available to ISGS at least 24 hours before 0.00 hours of the day of scheduling. The scheduling is proposed to start at 1 PM on D-2 day if D is the day on which implemented schedules are applicable.

After schedules are given by original beneficiaries as per their entitlement in a power station, it has been suggested that the original beneficiaries of an ISGS will have first right to give requisition for the URS power of the ISGS. Other original beneficiaries are proposed to be provided a window to reschedule a power left over by original procurer as per the procedure in vogue as per Order in Petition Nos. 310/mp/2014 dated 5.10.2015 and ROP in Petition No. 16/SM/2015 dated 5.1.2016.

After the original beneficiaries of a station have rescheduled the power, the original beneficiary whose power has still been left unrequisitioned may provide a formal communication to ISGS by 12PM on day before the day of implemented schedules. Such communication shall clearly specify the quantum of power and duration for which ISGS may sell the power in the market.

In case such power for which original beneficiary has allowed the generator to sell in the market has been sold in the market, beneficiary shall not be allowed to recall the power by rescheduling. In case power left unsold on the market, original beneficiaries may schedule the power from 4th time block as per procedure in vogue.

The gains made by the ISGS i.e the difference in selling price and the fuel cost including incidental expenses, shall be shared between the generator and the procurers who have surrendered their share, in the ratio of 50:50."

15.3 Comments have been received from Adani Power Limited (APL), CEA, Shri Vijay Menghani, Tata Power Trading Corporation Limited (TPTCL), Indian Energy Exchange (IEX), Adani Power Limited (APL), GRIDCO, NTPC, POSOCO, Neyveli Lignite Corporation Ltd (NLC), Maharashtra State Electricity Distribution Co. Ltd (MSEDCL), M.P Power Management Company Limited (MPPMCL), Gujarat Urja Vikas Nigam limited (GUVNL), Kerala State Electricity Board Limited (KSEBL)

15.4 Adani Power Limited (APL): APL has submitted that in order to achieve higher accuracy without frequent revisions by beneficiaries incentive should be linked with highest schedule in any time block amongst all revisions. Further, ISGS should be allowed to revise DC of Long Term/Medium Term beneficiaries if there is an eventuality of unit tripping/outage and the URS has been sold under collective transaction as revisions incase of any unit tripping/outage is not allowed in sale under collective transaction.

15.5 CEA: CEA has expressed the view that to implement the above provision of tariff policy in letter and spirit, 2 days ahead scheduling may not be required. It can be done with the existing day ahead schedule if the beneficiary provides details of URS well in time. CEA has suggested the methodology as intimated vide its letter dated 09/03/2016 addressed to MoP may be considered.

15.6 Shri Vijay Menghani has submitted as under:

(a) Difficulties are being experienced presently in utilisation of URS power, quantification of available URS power and cost / benefit should be detailed before considering amendment.

(b) It must be kept in mind that with sufficient generation capacity available, there would always be some power which will remain un-requisitioned. Each beneficiary of Central sector generating stations has different demand patterns and power control portfolios. With increasing penetration of renewables and obligation to purchase renewable, more and more quantity of URS power would be available depending on its variable cost.

(c) In formulating the time line of two day scheduling, the open access customers and power exchange timing has not been considered. State utilities (beneficiaries) are being asked to give their tentative drawl schedules when neither their open access customers nor they have participated in PX and know what are their cleared volumes.

(d) It may be clarified how URS power which is being proposed to be treated as reallocation will be considered for computation of monthly Transmission charges under POC. Say, for 7 day a new beneficiary avail URS of 100 MW power, whether this will be considered as LTA for transmission charges and original beneficiary will get corresponding benefit.

(e) Shri Menghani has suggested that this proposal which will affect already established scheduling procedure and not expected to benefit much in terms of utilisation of URS power, may be dropped.

15.7 **TPTCL:**As per IEGC, Second amendment clause 6.5.18, revision of declared capability by the ISGS(s) and requisition by beneficiary (ies) for the remaining period of the day should also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 4th time block. Draft Fifth amendment sub clause 8(d), provides that the URS which has been sold and scheduled by ISGS in the market (power exchange or through STOA) cannot be called back by the original beneficiary. A clarity regarding not allowing call back of URS in the draft amendment, in respect of existing provision of 6.5.18 may be allowed.

15.8 **IEX:** While reading above clause 8(c) of Regulation 6.5 it may be inferred that original beneficiary is required to communicate URS power by 12 PM (12 noon) of one day before the delivery day. However, intent of this clause is to provide URS information to ISGS by at least 24 hours before 0.00 hours of the day of scheduling

15.9 **GRIDCO :** For 8(a), GRIDCO is of the view that RLDC should allocate URS basing on the following conditions:

(i) When the total requisition for URS power of a particular station is less than or equal to the URS power available, requisitioning beneficiaries should get URS power as per their requisitioned quantum but not mandatorily in accordance with their shares in the ISGS.

(ii) When the sum of the requisitions is greater than the URS power available, then RLDC shall allocate proportionately basing on the requisitioned quantum by the beneficiaries of the ISGS.

For 8(c), GRIDCO is of the opinion that the draft regulation is not clear as to how this balance surrendered (unquestioned) power will be treated in case the original beneficiary intimate ISGS by 12 PM not to sell its surrendered quantum in the market i.e. whether it will remain surrendered to be called backby the original beneficiary as and when required as per the prevailing practice or this quantum shall be forcibly added to the drawl schedule of the original beneficiary even if the station is meeting its technical minimum without this power.

15.10 **NTPC has suggested as under:**

a) Clause 7.(iii) may be modified as:

"By 7 PM each day, RLDC shall convey "ISGS wise Un-requisitioned surplus (URS) power to SLDCs and Beneficiary-wise URS power to ISGS."

b) Clause 8(b) may be modified as:

"RLDC shall convey Beneficiary-wise URS power to ISGS after modifying the tentative net drawal schedule of the original beneficiaries after taking into account the URS requisitioned and associated transmission losses."

This is necessary because, based on this detail only, Generator will be able to proceed for sale of total available URS power in market and after sale, will be able to apportion the gains accrued from URS-sale among the concerned beneficiaries on pro-rata basis.

c) The requirement of communicating about the quantum is redundant. As per the Tariff Policy, the quantum not requisitioned is to be communicated by Beneficiary to the Generator. Under the scheduling process, the availability, entitlement, requisitioning and scheduling is being coordinated by RLDCs. Hence, the quantum which is not requisitioned should be provided beneficiary-wise by RLDCs to the Generators.

d) A mechanism may be further provided to prevent any initial undue over-requisitioning on (D-2) day as a margin/ cushion which may be subsequently surrendered in real time by beneficiaries at the time of actual drawl. This may frustrate the process of making available cheaper un-requisitioned power to other needy beneficiaries in the country as envisaged in the Tariff Policy. Accordingly, a persistent URS/ surrender of power by more than 5% of schedule in the individual time-blocks for consecutive 3 days may not be allowed.

15.11 POSOCO has submitted that a decentralized scheduling process is in place in the country where all participating entities have the liberty to change schedules, i.e., revise drawl schedules / injection schedules based on their requirement. There are no restrictions on the number of revisions that are permissible and this is a continuous and ongoing process. The available un-despatched/un-requisitioned surplus is changing continuously. The proposed amendment also gives the option of calling back the URS at multiple stages of the scheduling process along with option to the generator to sell in the market. The option of availing URS power at any time may lead to complexities in scheduling & accounting of URS power and poses an issue in calculations of margins for STOA. Further, it may also lead to disputes when the part URS power is sold in market and part URS power is requisitioned at any time and thereafter some machines at a generating station trip. Therefore, it is proposed to introduce the concept of "Gate Closure" in India.

15.12 POSOCO has proposed the following:

1) Once the tentative schedule is fixed by 7 PM of D-2, other beneficiaries cannot give requisition for the URS power.

2) State can give consent for sale of maximum 50% of their URS in each ISGS in the market. Rest of the entitlement shall take care of tertiary reserves, load forecast error, generation outages etc.

3) In case a state gives consent for sale of 50% of its URS power in market, it cannot recall the same thereafter even if the same is unsold in the market. This unsold power can be sold by the generator in either STOA (24X7 Market) or can be used by NLDC in Ancillary Services. In case a beneficiary fails to give consent for sale of its URS power in the market, generator may sell 50%

of URS power in the market. Rest 50% shall be reserved for tertiary reserve for that state.

For Regulation 6.5 Clause 8 (d): The constituents/RLDC should know how much of their individual beneficiaries surrendered quantum is sold in the market, out of the total sale by the ISGS, such that the same cannot be recalled back. Further, the types of STOA transactions may be clearly mentioned.

15.13 **Neyveli Lignite Corporation Ltd (NLC) has submitted as under:**

(a) The amendment brought about by the Commission in Clause 8 in line with MoP Guidelines to encourage Trading of URS is a welcome measure.

(b) A separate clause may be introduced to freeze the revision of requisition by the beneficiaries. Without this Gate Closure to unlimited demand revisions, the objective of maximum capacity utilization stated in the Tariff Policy may not be achievable.

(c) The scheduling procedure in the draft amendment may be integrated with the NLDC operating procedure for Reserve Shutdown of Generating Stations or Units for better implementation of sale of URS power. It may be ensured that summation of the schedules of the beneficiaries shall not be below the technical minimum of the station.

(d) Also, in order to have a level playing field and to ensure economic operation, Intra-State ABT is to be implemented for State Generators also.

15.14 **MSEDCL:** Clause 8 as notified by the draft for selling URS power by ISGS in the market by keeping liability of fixed charges with original beneficiary is not in the spirit of Grid standards. The availability of URS power is not hampering the grid standards

Objection- To clause 8 of the Draft:

The beneficiary has long term contract with ISGS and is paying capacity charges for its contracted capacity. It is the right of original beneficiary to call back its own share and schedule power, whenever required.If power is sold in market by ISGS, then there will not be any choice left with the beneficiary but to purchase/schedule costly power or to curtail load to match demand with availability. This will impose additional financial burden on the beneficiary losing its reliability margin in case of contingency. In case of sale of power by ISGS, no special benefit is given to original beneficiary except profit sharing above selling price of such power and fuel charge including incidental expenses. The margin of gain is also not defined.

15.15 **MPPMCL: For clause 8(c):** MPPMCL has submitted that, in place of "the original beneficiary shall communicate by 12:00 P.M. about the quantum and duration of such URS power to ISGS", the beneficiary shall communicate about the quantum and duration of such URS power to nodal agency i.e. SLDC/RLDC, being system operator and this agency in turn will communicate to ISGS to enable it to sell the URS in the market.

For Clause 8(d): MPPMCL has submitted that for URS power which has been sold and scheduled by ISGS in the market (power exchange or through STOA), it is proposed that in case of system condition warrant to do so, the original beneficiaries must have the right to call the URS power back, from 4th time block or any other time block considered appropriate by the Commission as the original beneficiaries are bearing the Annual Fixed Cost of their share in that ISGS

15.16 **GUVNL:** In order to facilitate sale of small quantity of URS power in power Exchanges, it may not be appropriate to shift the whole schedule paradigm from day head to two days ahead. Further, for a

RE rich state like Gujarat having large quantum of RE power which is infirm in nature, the Demand – Supply scenario is varying even in smaller time interval and therefore it would be difficult for the beneficiary states to provide ''net drawl schedule" two days in advance, particularly when many embedded customers are opting to buy power from the Power Exchanges which operates on day ahead basis and the actual picture is made available to DISCOM only by late evening.

It has been proposed in clause Regulation 6.5 Clause 8(c), that "if the original beneficiary fails to communicate to ISGS (by 12 pm), then ISGS shall be entitled to sell the URS power of beneficiary in the market".

In this regards, GUVNL has submitted that since the URS power once surrendered cannot be recalled by the original beneficiary even after taking the burden of fixed charge, it would not be prudent for the original beneficiary to convey a blanket consent for sale of power 2 days in advance.

15.17 **KSEBL:**

(a) The state utilities are mandated to operate the grid in the most economical way as per the Electricity Act, 2003. The cost of power in the market may be lesser than the variable cost of CGS on several occasions. The finalization of the schedule of CGS will depend a lot on the availability of power from market. Hence, a surrender proposal on D-2 is practically ruled out and may be possible only if there are significant contribution from must – run internal sources. This proposal goes against these principles.

(b) The state utilities are bound to maintain supply without interruption. The availability of power from various sources can be best finalized on D-1 conditions. Still there can be difference in the actual availability. The variation of demand is also to be expected in D-2 conditions as the weather conditions may vary in 2 days. Thus, surrender proposal on D-2 condition is very difficult considering the requirement of load – generation balance in real time.

(c) This arrangement can function only if a real time market with sufficient depth is available to the system operator. At present, the contingency market is very shallow. There are not much participants in this market. The participants often come with interactions through the exchanges. Even if contract is made, it takes 3 hours as per regulation and 4-5 hours as per experience to materialize a contract through the contingency market. The stringent requirement of funds in the market and uncertainty in the availability of power in the contingency market are also affecting the market operation. In this condition, the constituents may not be able to declare the URS possibility faithfully on D-2 horizon.

(d) Another way of utilization of the surplus with the states as and when it happens is to permit the beneficiaries to sell the power in the contingency market or day – ahead market with source mentioned as the source of injection itself. That is, the beneficiary shall be permitted to sell the entitlement at a rate suitable for the beneficiary from the generating station itself. This arrangement has got the following benefits.

(i) The beneficiary has got better control over the surplus and can sell from any generating station where they have a stake either as share from, CGS or as LTA holder.
(ii) The point of injection being at the generator bus, chances are that the transmission constraints may not come up.

(iii) When the beneficiaries sell the power on their own from the beneficiary state periphery, losses and transmission charges are applied twice, which can be avoided.

(iv) In the event of an outage of the CGS generator, the sale can be curtailed within 4 time blocks

(e) For a good real-time market and even contingency market to function, real time TTC revision is to be done by POSOCO. The rules regarding fund management in the exchanges also need to be reviewed. Hence, the states shall have freedom to recall surrender in the shortest possible time to maintain LGB and to reduce the deviation.

(f) The present regulations permit 4 time blocks for revision of share in the event of contingencies. Though it is not mentioned that the revision shall be done only after 4 time blocks as per the regulations, POSOCO is permitting only after 4 time blocks event if the communication regarding rescheduling is possible within that period. If the process can be made fully online, including the requisition and consents, this duration can be further reduced. This will become handy especially in cases where contingency applications are submitted and also when the surrendered power is immediately taken by another utility.

15.18 **Analysis and decision**

15.18.1 We donot agree with suggestions of APL that incentive should be linked with highest schedule in any time block amongst all revisions. Scheduled revision is a flexibility available with beneficiaries to manage their demand generation scenario judiciously. We are further not considering to allow the revision of the DC for collective transaction as of now.

15.18.2 We agree with the suggestion of CEA that to implement the tariff policy,2 day ahead scheduling may not be required. As suggested by CEA, the proposal of 2 day ahead scheduling is not being considered and as the concept of standing consent have been introduced. Further, the timing of beginning of day ahead scheduling has been advanced by 2 hours i.e. it shall begin from 6 AM rather than 8 AM.

15.18.3 Shri Vijay Menghani has stated that a state utility as well as its open access customers bid in the power market and only after ascertaining actual volume through power exchange, a decision is taken as to how much power is to be scheduled from CGS. He has stated that this efficiency gain of market will vanish once the proposed amendment is implemented. We find that there is merit in the argument of Shri Vijay Menghani. However, it is also necessary for the ISGS to know how much un-requisitioned power they are allowed to sell in the market before the start of the selling window at the Power exchanges. In our view, State Discoms are required to take a call on the manner they would like their demand to be met before opening of the power exchange window and inform ISGS about the quantum they are willing to allow for sale in the market by ISGS. Accordingly, the decision of providing the consent is left with the beneficiary as per its assessment.

15.18.4 Shri Vijay Menghani has stated that no mechanism is going to help in making any appreciable change in utilization of URS power. The utilization of URS power would depend on the relative requirement of such power by other beneficiaries. However, we see no harm in facilitating utilisation of URS in terms of the Tariff Policy.

15.18.5 Shri Vijay Menghani has raised issues regarding fixed charge liability with the original beneficiary even when the right to recall is not there. In this regard it is clarified that the framework proposed is a facilitative framework with due consent of beneficiaries where unutilized power can be utilized with sharing of benefits with beneficiaries. Hence, it is for the beneficiaries to assess the best course of action for them.

15.18.6 TPTCL has commented that a clarity is required between clause 6.5.18 of IEGC which allows a beneficiary to revise the schedule vs. proposed clause 8(d) which states that power sold by ISGS in the market cannot be called back by the beneficiaries. In this regard it is clarified that the power which gets sold in the market (STOA bilateral and collective transaction) after due consent of the beneficiary, is not allowed revision of schedule under the extant regulations, and hence the provision of not allowing the recall has been made. Regulation 6.5.18 has to be read in conjunction with the amended regulation 6.5.4(d).

15.18.7 The comment of IEX with regard to timing of URS as 24 hours no longer survives in view of the final amendment done.

15.18.8 We agree with GRIDCO's suggestion on modalities of URS reallocation which is the current mechanism of URS reallocation in vogue. GRIDCO has further raised a query as to how the balance un-requisitioned power will be treated in case original beneficiary intimates to ISGS not to sell its surrendered quantum i.e. whether it will be forcibly added to the drawl schedule of the beneficiary or the beneficiary will be free to recall it as per the prevailing regulations. In this regard, it is clarified that the un-requisitioned power will not be added forcibly to the drawl schedule of the beneficiary and it will be free to recall it as per the prevailing regulations.

15.18.9 NTPC has suggested that a mechanism may be provided to anybody over requisitioning on D-2 as a margin which may be subsequently surrendered in real time by beneficiaries which may frustrate the process the making cheaper URS available to other beneficiaries. NTPC has suggested that persistent surrender of power by more than 5% of schedule in individual time blocks for consecutive 3 days may not be allowed. In this regard, we observe that beneficiaries can schedule the URS surrendered by another beneficiary within 4 time blocks as per the prevailing regulations. Hence we do not agree with NTPC that cheaper URS will not be available to other beneficiaries. Further, we do not agree that limit should be set on the amount of surrender as surrender of share is a voluntary activity which should be as per the assessment of the beneficiary as per its demand and supply scenario.

15.18.10 POSOCO has stated that the option of availing URS power at any time may lead to complexities in scheduling and accounting of URS power and processing and issuing calculation of margins for STOA. Further, POSOCO has proposed to introduce the concept of “Gate Closure”. We are of the view that the flexibility available with beneficiaries in rescheduling cannot be taken away under the current market mechanism. We agree that there is a need to reform the market especially in view of upcoming renewables and the Commission is already working on the same in consultation with stakeholders.

15.18.11 We do not agree with POSOCO’s suggestion that once the consent for sale of URS is given by beneficiary it cannot recall the same even if it remains unsold in the market. A power which is left unsold should be allowed to be recalled back by the original beneficiaries.

15.18.12 POSOCO has further suggested that types of STOA transactions may be clearly mentioned and generator should intimate the details of URS quantum of individual beneficiaries sold in the market. We agree with the suggestion of POSOCO and accordingly, provisions have been made to provide that ISGS shall intimate the details of the share of power of individual beneficiaries sold in the market to the respective RLDC. The type of STOA transaction or for that matter, the word "market" has not been elaborated to keep it open with regard to the products available in the market.

15.18.13 NLC has suggested to freeze the revision of requisition by the beneficiaries. We do not agree to introduce any freezing on the number of revisions by the beneficiaries as of now. But beneficiaries should avoid too frequent revisions in due consideration of capability of generating station.

15.18.14 NLC has further suggested that summation of beneficiaries shall not be below the technical minimum. In this regard, there are separate provisions available in IEGC to deal with the issue of technical minimum and reserve shutdown and hence no changes are effected in the instant regulation.

15.18.15 MSEDCL has stated that beneficiary who is paying the capacity charges should have the right to call back its own share whenever required. We agree with MSEDCL and accordingly, the sale of power is allowed only in case of availability of express consent of the beneficiary.

15.18.16 MPPMCL has submitted that in place of original beneficiary communicating with ISGS about quantum and duration of URS power, the beneficiary shall communicate such quantum and duration to the nodal agency i.e. SLDC/RLDC who intern will communicate with ISGS. We are of the view that beneficiary should communicate its consent to ISGS to avoid any complications. A copy of the consent should, however, be marked to SLDC/RLDC.

15.18.17 MPPMCL has further requested that the URS power already sold by ISGS in the market should be allowed to be called back from 4th time block since original beneficiaries are bearing the annual fixed cost. In this regard, a provision of express consent has been made in the regulations. Hence, it is up to the beneficiary to provide the consent under the extant regulatory provisions. However, power which is already sold cannot be allowed to be called back

15.18.18 GUVNL has submitted that it may not be appropriate to shift whole scheduling paradigm from day ahead to 2 day ahead to facilitate sale of small quantity of URS power. It is difficult for the beneficiary to provide the net drawl schedule 2 day in advance, in view of renewables and embedded customer buying power from exchanges. KSEB has also opposed the proposal of 2 day ahead scheduling. Keeping in view the comments of GUVNL and KSEB,2 day ahead scheduling is not considered in this amendment.

15.18.19 KSEB has further brought to our notice that currently contingency market is very shallow even if the contract is made as it takes 3 hours as per regulation and 4 to 5 hours to materialize the contract. In this regard, we observe that there is a need to have faster clearing time in the contingency market especially in view of upcoming renewables. KSEB has further requested that beneficiaries should be allowed to sell the surplus power at the source of injection itself to avoid application of double transmission losses and charges. Further KSEB has suggested that real time TTC revision should be done by POSOCO. KSEB has also requested that the process of rescheduling should be made fully online including requisition and consent so that the time period of 4 blocks to revise the schedule can be reduced. The

Commission agrees with KSEB on the above suggestions and direct NLDC to explore possibility of reducing the time of scheduling in consultation with Power Exchanges and put up a proposal to the Commission.

15.19 **Addition at the end of Clause (19) of Regulation 6.5**

15.19.1 Following new Para was proposed to be added at the end of clause (19) Regulation 6.5

"Provided that if a generator is not able to restore the unit by the estimated time of restoration, RLDC shall revise the schedule only one more time on the basis of new estimated time of restoration and the revision schedule shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one."

15.19.2 Comments have been received from Adani Power Limited (APL), WBERC, MB Power (Madhya Pradesh) Ltd, Central Electricity Authority (CEA), Shri Vijay Menghani.

15.19.3 **Adani Power Limited (APL):** Generator should be allowed atleast two revisions after the first revision which is done just after the unit tripping /outage. Also, if the Unit could not be synchronized once it has been lit-up, due to any technical difficulties, the Generator should be allowed to carry out revisions. The gravity of problem is known only after the problem is being attended' and thereafter during testing time.

15.19.4 **SRPC:** The draft Regulations states that if a generator is not able to restore the unit by the estimated time of restoration, RLDC shall revise the schedule considering the unit out. In this regard, SRPC has submitted that the revised schedule keeping in view the ramp rates shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one after the unit is synchronized. Generator would keep the buyer/ beneficiary and RLDC informed every three hours of the likely revival in the intermediate period.This may ensure better LGB and avoid gaming, if any. Periodical information by Generator would help in LGB/ Purchase planning be the buyer/ beneficiary.

15.19.5 **WBERC:** Commercial treatment needs to be clearly specified in case the generator fails to restore the unit within the revised restoration time.

15.19.6 **MB Power (Madhya Pradesh) Ltd** has suggested following additional para at the end of clause 19.

"Due to unforeseen delays in restoring a unit, there should not any restriction on number of times for revision of power scheduling under Long Term /Medium Term Open Access. However, for power scheduled under STOA/ Collective Transactions, the restrictions on number of times for revision of power scheduling may be done in accordance with the proposed draft amendments".

15.19.7 **CEA:** Plant revival after forced outage is a complex activity and accurate estimation of the time thereof is a difficult task. As the scheduling is being done on daily basis, it is suggested that the generator may be allowed to confirm its revival schedule once a day, when it is selling power under STOA & goes under forced outage.

15.19.8 **Shri Vijay Menghani:**

(a) As scheduling is being done under day ahead basis, it should be allowed at least one revision per day. The plant revival post a force shutdown is a complex activity and its correct estimation is a difficult thing. The revision of scheduling under force outage was provided to avoid unbalance drawl by buyer entity of STOA in case of forced shutdown. As scheduling is being done on daily basis, it will be prudent that the generator may be asked to give its plant status on daily basis before PX transaction i.e say at 9 AM, so that its buyer can make alternate arrangement. This will avoid unnecessary deviation from schedule. The same intent was expressed in the Statement of Reasons of First Amendments of IEGC while dealing with CEA suggestion. The relevant para is extracted as under:

" 43.10 On draft Regulation 6.5.19, CEA has suggested the following: “In case of a forced outage all generating stations irrespective of their nature of PPA, whether long term, medium term or short term, should be allowed to revise their schedule with the exception of schedules for day ahead collective transactions cleared through a power exchange. If large number of generating stations supplying power under long term, medium term and short term bilateral contracts are not allowed to revise their schedule under forced outage, it may result in serious grid imbalances.

"CEA also submitted that in the UI Regulations, 2010, a limit has been put on under injection by the generator. To do so, the generators must have facility to revise their declaration incase of forced outages. However, this Regulation of proposed IEGC allows only generator with two part tariff and long term contract to revise their schedule in case of forced outage.

Therefore to have a level playing field and to enable generators to generate close to their schedule, generators supplying through bilateral transactions under open access should be given right to revise declaration in case of forced outages. Since such events are not so common in a well maintained generating station**, a limit say once per day may** also be specified for this purpose.

43.11 We are in agreement with the views of CEA. The issue of handling Grid imbalance is important and Regulation 6.5.19 has been modified to allow revision of schedules to a generator of capacity of 100 MW or more, in case of short term bilateral transactions, incase of forced outage, with the objective of not affecting the existing contracts, the revision of schedule shall be with the consent of the buyer till 31.07.2010. Thereafter, consent of the buyer shall not be a prerequisite for such revision of schedule."

15.20 **Analysis and Decision**

15.20.1 APL has requested that atleast 2 revisions should be allowed after the first revision is done on the ground that gravity of the situation is known after the problem is attended. Considering the suggestion, revision is allowed once in a day.

15.20.2 SRPC has suggested that if the generator is not able to restore the units by the estimated time of restoration, RLDC shall revise the schedule considering the unit out and that generator would keep the buyer and RLDC informed every 3 hrs of the likely revival. We do not agree with SRPC as onus of providing correct estimated time restoration is with the generator in case of forced outage of its units. However, we have provided the flexibility of revision of schedule once in a day for such cases.

15.20.3 WBERC has sought clarity on commercial treatment in case a generator fails to restore the unit within the revised restoration time. In such a case, the schedules of the generator shall be as intimated by the generator and accordingly, the liability of deviation, if any, shall arise as per the extant regulations.

15.20.4 MB Power has prayed that due to unforeseen delay in restoring in unit, there should not be any restriction on number of revisions under LTA/MTOA. In this regard, it is clarified that the instant Regulation 6.5.19 pertains to generating stations selling power under short term bilateral transaction only.

15.20.5 Shri Vijay Menghani and CEA have suggested that generator may be allowed to confirm its revival schedule once in a day. We agree with the suggestion and accordingly, the amendment has been done..

15.21 **Addition of new Regulation 6.5(A) added after Regulation 6.5 as follows:**

"6.5 (A) Scheduling and commercial settlement of energy exchanged under Ancillary services including Spinning Reserves and URS

a. The Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 provides detailed frame work of scheduling and despatch, withdrawal, energy accounting and commercial settlement of Reserves Regulation Ancillary Services.

b. In case of spinning reserves, the Scheduling and commercial settlement of energy exchanged shall be as per the framework to be notified separately by the Commission.

c. In case the un-requisitioned surplus power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation and the fixed charge and variable charge for such energy exchanged shall be borne by the other beneficiary(ies).

d. In case of sale of un-requisitioned surplus power in market, the generator and the original beneficiary would share the realized gains in the ratio of 50:50. This gain shall be calculated as the difference between selling price of such power and fuel charge including incidental expenses. Subject to provisions to CERC Tariff Regulations, the liability of fixed charge in such case shall remain with original beneficiary."

15.21.1 The Commission had given following rationale while proposing said amendment:

The new regulation provides the methodology for scheduling and commercial settlement of energy exchanged under Ancillary services including Spinning Reserves and URS.

15.21.2 Comments have been received from GRIDCO, Tata Power Trading Corporation Limited (TPTCL), NTPC , POSOCO, KSEBL,MB Power (Madhya Pradesh) Ltd, Maharashtra State Electricity Distribution Co. Ltd (MSEDCL), M.P Power Management Company limited (MPPMCL), Gujarat Urja Vikas Nigam limited (GUVNL)

15.21.3 **GRIDCO**: Following clarifications are required in the scenario of power sold through Power Market (Power Exchange):

i. In case of sale of un-requisitioned power in power market by a generator, whether the same shall be sold in day ahead market of Power Exchanges only or also through Term-ahead Market.

ii. The methodology of determination of daily bid price as the market price, which varies on daily/ hourly basis may be clearly stipulated. In this context, it is to mention that beneficiary's URS may comprise of power of multiple stations having different rates.

iii. Whether the generators shall seek confirmation from the beneficiaries on daily basis for the bid prices and the quantum before placing the bid at power markets.

iv. If at the end of the month, the per unit fuel cost of a particular station, billed by NTPC becomes more than the net realised per unit sale proceed, it is not clear from the draft regulation, who will bear the differential amount.

v. Similarly it is often seen that the fuel charge of NTPC stations get revised up to 20 paisa/kwh afterwards from that which was originally billed. Under such changing variable rate scenario clarification is required, at which energy charge rate (ECR) the sold power should be considered for settlement between NTPC and beneficiary (ies). It is not clear who would bear financial loss due to such upward revision in ECR. Further it may be clarified whether there should be any price cushion to take care of such probable upward revision, if any. The benefit sharing mechanism between the generator and the beneficiaries should be explained in a more elaborate manner.

vi. In case of a beneficiary, who is selling its surplus power through Power Exchange as a member, it is not clear from the draft regulations, how the beneficiary would be benefited more in case of sale of same surplus power through same Exchange by NTPC.

15.21.4 **Tata Power Trading Corporation Limited (TPTCL):** The amendments proposed to Regulations 6.5 should also be applicable to generating stations other than Central Generating Stations, which have signed Power Purchase Agreements with two or more than two entities, for scheduling power through Long Term Access. As per draft fifth amendment, the original beneficiary shall communicate by 12 noon about the quantum and duration of such URS power to ISGS to enable ISGS sell same in the market. However, it is suggested that original beneficiary shall communicate by 10 AM, one day ahead, about quantum and duration of URS to ISGS. This would enable ISGS to bid the URS on Exchanges as per existing bidding window between 10 hrs to 12 hrs. in Day Ahead Market.

Further, in case URS power is scheduled under STOA through Collective/Bilateral transaction, the Commission may provide suitable off-set mechanism for POC charges as POC Injection and POC withdrawal charges, for the URS quantum are borne by concerned buyers/DICs, mostly by beneficiary States/DISOCMs. Since URS power is emanating power from Long Term PPAs which otherwise entitle for scheduling under Long term Access, for which transmission capacity is built, the transmission capacity towards

URS power should be suitably allocated to the market for trade of URS in the short term market.

15.21.5 **NTPC:** For New Regulation 6.5(A) (a),(b) and (c)

Comments: The methodology of temporary re-allocation for URS scheduling among beneficiaries is implemented for more than 5 years. However, the URS power of ISGS has been still increasing including from the Pit head power stations.

In order to facilitate scheduling of more URS power, it is required to allow scheduling of URS power from an ISGS in the real time (from 1900 hrs of D-1 day) by any of the State beneficiary in the country and should not be limited to only the original beneficiary of the ISGS.

Further, the scheduling of such URS Power should be permitted only at variable charge and the fixed charge liability for such quantum should remain with original beneficiary.

For Regulation 6.5(A)(d):NTPC has suggested to be included and specified in the Regulations to avoid any post-sale issue.

(a) The basis of fuel charge for the purpose of calculating Gain may be clarified in the Regulations - whether it will be the Actual Variable Charges or Normative Variable Charges.

(b) The gain sharing by ISGS will be done on monthly basis.

(c) The final Variable/ Fuel Charge for the Gain calculation shall be reckoned after the Third Party sample results for GCV of coal for the month is received. There will be no subsequent revision in the Fuel Charge (upward or downward) for the purpose of Gain calculation.

(d) If the URS power sale is lower than the total URS power available from different beneficiaries in an ISGS, the gain sharing will be on pro-rata basis in proportion to URS made available by concerned beneficiary.

(e) In case of any Unit Outage and consequent revision of Station DC during real-time operation, URS power of each beneficiary will be revised. Accordingly, URS contributed by beneficiaries for the Gain calculation will also be revised.

15.21.6 **POSOCO**: 6.5 (A) (c) may be deleted as any other beneficiary shall not be allowed to give requisition for unallocated power.

In case the suggestions given above are not acceptable to the Commission, then following changes in the proposed amendments may be done for better clarity. POSOCO has suggested that in order to bring clarity that only the beneficiaries who have requisitioned the un-requisitioned surplus power shall bear the fixed and variable charges of such energy. Accordingly, POSOCO has suggested the following changes:-

"In case the un-requisitioned surplus power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation and the fixed charge and variable charge for such energy exchanged scheduled shall be borne by the other beneficiary (ies) ***who have availed the unrequisitioned surplus power"***

15.21.7 **KSEBL :** Following modifications may be added with respect to sharing of gains due to sale of URS in market:

"This gain shall be calculated as the difference of selling price of such power and the actual variable cost billed to the beneficiaries for the corresponding period. "

Further, as a deterrent to avoid sale at lower prices, the following may also be added

"..if the sale price is less than the actual variable cost or if it is discovered subsequently by the commercial subcommittee of the RPC that the variable cost worked out is manipulated for the period under consideration, the generator shall reimburse the fixed cost of units so sold worked out on the basis of the generation at target plf or actual plf, whichever is lower".

15.21.8 **MB Power (Madhya Pradesh) Ltd** has suggested the following new para in the proposed New Regulation 6.5 (A) (d) in the Principal Regulations: In case of sale of un-requisitioned capacity in market, the Profit/ Gain Sharing Mechanism between the generator and the original beneficiary is governed in accordance with the provisions of the PPA entered into between these parties. Such Profit/ Gain Sharing Mechanism(s) are different for different PPAs. Further, for such PPA(s), where tariff is determined/ adopted by the respective SERC(s), there may be difficulties in sharing gains arising out of sale of un-requisitioned capacity in market in the ratio 50:50 as proposed in the draft amendment to the Principal Regulations.

Accordingly, it may be amply clarified in this proposed amendment that gains arising out of sale of un-requisitioned capacity in market may be shared between generator and the original beneficiary in accordance with the relevant provisions of the PPA(s) between these parties. However in cases where no such Profit/ Gain Sharing Mechanisms specified in the PPA(s) and/ or the applicable regulations of the concerned SERC, such gains would be shared between the generator and the original beneficiary in the ratio of 50:50.

15.21.9 **MSEDCL:**

Suggestion – To clause 6.5 (A):

In the proposed amendment, in case of sale of un- requisitioned surplus power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation and fixed charges and variable charges for such energy exchanged shall be borne by the other beneficiary(ies).

However, in present surplus power scenario, if ISGS station is running below technical minimum. The beneficiary other than original beneficiary supports in URS for the station to run at is technical minimum. In such case, for the support up to technical minimum of station, fixed cost against URS shall not be charged to the other beneficiary who is supporting station in URS.

15.21.10 **MPPMCL: For Regulation 6.5 (A) (c):**

"This methodology is not prudent as with the capacity charges, the transfer of URS does not qualify in Merit Order Dispatch of the beneficiary and therefore most of the time is not scheduled, due to which the ISGS, which is not even getting the TMM schedule in off peak hours goes under RSD. This is further hitting the generator and the beneficiary because, other than off peak period when it qualifies for delivering normal schedule of the beneficiary, the plant is not available. Thus to overcome it and to make best use of URS power, MPPMCL has proposed as follows-

1. "The URS may be transferred with 50% capacity charges and 100% variable charges to the availing beneficiary. The balance 50% capacity charges are payable by the original beneficiary who surrenders the power but will have lien to take back such power if required from the 4th time block."

OR

"The URS may be transferred with 100% capacity charges and 100% variable charges to the availing beneficiary. In such cases the original beneficiary will not have lien to take back such power once scheduled by other beneficiary".

2. "The ISGS be allowed to sale in the market, the quantum to meet its TMM without asking from the beneficiaries before taking the decision of going in to RSD."

As regards Regulation 6.5 (A) (d), MPPMCL has submitted that in case of sale of un-requisitioned surplus power in market by ISGS, **<u>the generator and the beneficiaries shall share the realized gain in ratio of 20:80</u>** as the ISGS is a regulated entity and it has been allowed a return of 15.5% on the equity invested and after grossing up of RoE with the effective tax rate (about 21.34%) of the financial year. The gain shall be calculated as the difference between selling price of such power and fuel charges including **actual incidental expenses subject to maximum of 1 paise per unit**. This has been proposed as the liability of Annual Fixed Cost in such cases has been proposed to remain with original beneficiary.

15.21.11 **GUVNL:** As per proposed amendment in Clause 6.5(A)(d), the gain towards sale of URS power shall be calculated as the difference between selling price of such power and fuel charge including incidental expenses. In this regard, it needs to be clarified as to whether the actual fuel charge or normative fuel charge is to be considered since the settlement is made on monthly basis. In case the URS power surrendered by the original beneficiary is requisitioned by the other beneficiaries of the ISGS, it shall be treated as reallocation wherein the fixed and variable charge for such energy exchanged shall be borne by the other beneficiaries availing URS. However, in case the URS power is sold in power market, the generator and the original beneficiary should share the realized gains in the ratio 50:50.

In case of utilization of URS by another beneficiary within the Region, the Regional Beneficiaries may be allowed to decide the % of fixed charges to be shared between the existing beneficiary and the buyer beneficiary so as to ensure more scheduling of URS by the existing beneficiaries. Moreover, the reduced burden of fixed charges will incentivize the beneficiaries to off take more URS and there will be no burden of trading margin and all incidental expenses incurred towards sale of URS in Power Market. Moreover, the original beneficiary will have the right to recall the surrendered power as per existing provisions which is not available in case of sale in Power market.

15.22 **Analysis and Decision**

15.22.1 GRIDCO has sought clarification whether the un-requisitioned power shall be sold in day ahead market at power exchange or term ahead market also. In this regard, it is clarified that the sale of power shall depend upon the period of consent given by the beneficiary.

15.22.2 GRIDCO has further sought clarity on the methodology of determination of day bid price of the generator and whether the generator shall seek confirmation from the beneficiaries on daily bid prices before placing the bid. We are of the view that the generator should be allowed to take call on the bid price and as such, it is not necessary for the generator to seek confirmation from the beneficiaries on bid prices before placing in the bid.

15.22.3 GRIDCO has further stated if the fuel cost of the station at the end of the month is more than the net realized proceed from the sale who will bear the differential amount. It is clarified that a provision has been made in Regulation 6.5(A)(c) that there shall be no sharing of loss by the beneficiaries as a result of such market sale of URS power. GRIDCO has sought clarification on the fuel charge which will be considered to calculate the settlement between generating station and beneficiary since fuel charge gets revised upto 20 paise/ kwh afterwards than that was originally billed. It is clarified that settlement shall be at the variable charge of the station. In case it is revised at a later date, ISGS shall carry out adjustment accordingly.

15.22.4 TPTCL has prayed to offset the STOA charges under collective/bilateral transactions in case of sale of URS power. It is clarified that the offset will be as per the applicable Sharing Regulations.

15.22.5 NTPC has suggested that URS power should be allowed to be scheduled to any of the state beneficiary in the country. It is clarified that the provisions of sale of URS power have been elaborated vide Order dated17.10.2017in petition No.16/SM/2015.

15.22.6 NTPC has further suggested that the fuel charge for gain calculation should be considered after the third party sample results for GCV of coal for the month is received and that there will be no subsequent revision in fuel charge for the purpose of gain calculation. We are of the view that gain calculation should be done at the variable charge rate at which variable charges are billed by the generator to the beneficiary for its scheduled power. In case variable charges undergo a change subsequently, generator shall revise the gain calculation accordingly.

15.22.7 NTPC has suggested that gain sharing should be on prorata basis in proportion to URS made available by concerned beneficiary in case URS sale is lower than the total URS power available. We agree with NTPC in this regard.

POSOCO has suggested to bring clarity that only the beneficiaries who have requisitioned the URS power shall bear the fixed and variable charges of such energy. We agree with POSOCO and the necessary clarity has been provided.

15.22.8 KSEB has suggested that there should be a deterrent to avoid sale at lower prices by generator. We are of the view that sale / bid price shall be decided by the generator with sharing of benefits. In any case, loss shall not be shared. Hence concerns of KSEB gets addressed.

15.22.9 MB Power has stated that the gain sharing should be as per the PPA in case PPA has specific provisions regarding the same. We agree with MB Power and accordingly, provisions has been made to share the gain in the ratio of 50:50 or mutually agreed terms.

15.22.10 MSEDCL has suggested that in case a beneficiary schedules URS power to support a generating station to run at technical minimum, fixed charges should not be charged to such a beneficiary. We are of the view that the treatment of URS power shall be as specified in the regulations.

15.22.11 MPPMCL has stated that with the capacity charges, the URS power does not qualify in the merit order dispatch of the beneficiary and hence it has suggested that URS may be transferred with 50% capacity charges to the availing beneficiary with a lien with the original beneficiary to recall such power for 100% capacity charges without a lien to recall back. We are not inclined to disturb the prevailing methodology of liability for fixed charge vis a viz right to recall as suggested by MPPMCL.

15.22.12 MPPMCL has also suggested that ISGS may be allowed to sell such power in the market to maintain its technical minimum schedule without asking the beneficiary before taking the decision of going into RSD. We don't agree with the suggestion of MPPMCL as selling power in the market without consulting the beneficiaries will result in disputes with regards to sale of power.

15.22.13 MPPMCL has suggested that the sharing of gain should be in the ratio of 20:80 and that the actual incidental expenses should be allowed subject to the maximum of 1paise/ kwh. We do not agree with MPPMCL regarding the suggested sharing and putting a cap on the maximum incidental expenses which is allowed as per the actual.

15.22.14 GUVNL has sought clarity on whether the actual fuel charge or normative fuel charge is to be considered for settlement. It is clarified that the variable charge billed as per CERC tariff Regulations shall be considered for settlement.

15.22.15 GUVNL has also suggested that in case of utilization of URS by another beneficiary within the region, regional beneficiaries may be allowed to decide the percentage of fixed charges to be shared between existing beneficiary and the buyer beneficiary. We are not inclined to modify the prevailing mechanism of sharing of fixed charges under URS.

16 Additional Comments: Additional Comments have been received from POSOCO, MB Power (Madhya Pradesh) Ltd, Tata Power Trading Company Limited (TPTCL)

16.1 POSOCO :

Miscellaneous

a. The term 'System Operator' though widely used, could be formally defined as under:

*"**System Operator**: Any load dispatch centre viz. the National Load Despatch Centre established under section 26(1) of the Act or any Regional Load Despatch Centre established under section 27(1) of the Act or any State Load Despatch Centre established under section 31(1) of the Act engaged in the function of power system operation;"*

b. Further the definition of primary, secondary and tertiary reserves may also be included in the grid code

c. It has been observed that even after 72 hr trial run, some regional entity generators do not declare commercial operation immediately and continue to inject infirm generation. Following may be added as note after clause 6.3.A.3 of IEGC:

"After generator announces start of 72 hour trial & completes the same, it shall be incumbent on the generator to either declare COD or communicate the deficiencies observed in trial run & intimate likely dates of next trial"

d. There have been instances where the home state drawing power from any ISGS being scheduled by RLDCs does not agree to pay for inter-state transmission charges and losses, citing STU connectivity also at that point. As any case by case exemption from interstate transmission charges & losses is subjective & may lead to disputes, it is proposed to add following in clause 6.4.2 (c)

“Inter-State transmission charges and losses shall be applicable for scheduling from one regional entity to other regional entity (including embedded entities) inaccordance with CERC Regulation on "Sharing of Transmission Charges and Losses in ISTS Regulation 2010” and any amendment thereof. Accordingly all the transactions scheduled through RLDCs shall be subjected to Point of Connection(POC) injection as well as withdrawal charges and losses."

e. A generating station applies for long term access and medium term open access in advance considering the likely commissioning of the generating units. Accordingly, LTA/MTOA is being approved by the CTU. Power Purchase Agreement is also signed considering the likely commissioning of units in future. It may happen that at the time of operationalizing the LTA/MTOA, the total LTA/MTOA quantum is greater than the installed capacity at that time. In such situations, it is desirable that the schedule of that generator is limited to ex-bus installed capacity. Recently, similar case was also encountered with a generating station in Western Region. Therefore, it is proposed to add following after IEGC clause 6.4.14:

   “.....If the ex-bus installed capacity or sent out capability of the plant is less than the PPA signed or/and LTA/MTOA operationalized by CTU, then RLDCs shall commence operationalization of schedules limited to the ex-bus installed capacity"

   Further, In case of multiple contracts, scheduling priority can be given either based on the date of operationalization of the contract or all contracts scheduled on a pro-rata basis. The Commission may further give directions in this regard and incorporate it suitably in the IEGC, else it is likely to lead into a number of disputes.

f. The IEGC provides for a limit of maximum 16 revisions for RE generators in a day whereas no such limit for declared capability revision exists for conventional generators. With no limit on the number of revisions for conventional generators, there is no certainty to the states regarding power available during a day. Therefore, it is proposed to limit the number of revisions of a conventional generator to 4 (i.e. 25% of maximum revisions for RE generators). Accordingly following may be added in clause 6.5.18 of IEGC:

"Provided that the maximum number of declared capability revisions of conventional generators shall be limited to 4 during a day"

g. It has been observed that some States give zero requisition from a central generating station during off peak hour and give full requisition during peak hour. At times, this leads to a schedule less than technical minimum for these generating stations during off peak hour which poses a challenge to run the machine during off peak hours. Therefore it is suggested that the off peak to peak requisition ratio may be limited to 55%. Accordingly, the following may be added in clause 6.5.4 of IEGC:

   "Provided that the ratio of off peak to peak drawl schedule given by each beneficiary for each ISGS shall be at least 55%."

h. It has been observed that gas stations with multiple fuel gives major portion of its declared capacity (DC) for the costliest fuel. Since, States generally would not give requisition for costly fuel, the certification of availability of these generating stations becomes a challenge. Therefore, it is proposed that certain provisions to check gaming in these cases may kindly be included in the Grid Code.

In addition to these suggestions, it is also felt that the amendments need to suitably factor the developments in the past within the country and worldwide also such as Assessment of Frequency Response Characteristics, Testing of frequency response, Reserves, Ancillary services, Draft amendment to the CEA (Technical Standards for Connectivity to the Grid), Regulations, 2007. Accordingly, certain new definitions and provisions related to frequency control are proposed which are attached as Annexure II. Some of the references used to formulate these definitions/provisions are given below:

16.2 **MB Power (Madhya Pradesh) Ltd :**

1) Any discrimination amongst the power projects defined as "ISGS" in IEGC is unwarranted. Accordingly, the IPPs qualifying as "ISGS" under IEGC shall be treated at par with CGS/UMPP for scheduling and commercial settlement of energy exchanged under Ancillary services including Spinning Reserves and URS. As such, for any IPP covered under the definition of "ISGS", the un-requisitioned capacity by a PPA beneficiary should be considered under URS category.
2) As per the provisions 6.4 (18), 6.4 (19) and 6.5 (32) of the Grid Code, any ISGS including an IPP is required to declare the plant capability and the same has to be demonstrated by such ISGS as per the directions of concerned RLDC. Further, the concerned RLDC is required to properly document such declared plant capability of the various ISGS coming under its control area.

   As per Regulation30 (3) of the CERC Tariff Regulations 2014-19, for the purpose of computation of "Capacity Charges", Average Declared Capacity (DCi) of a generating station is required to be certified by the concerned Load Despatch Centre (i.e. the concerned RLDC for any ISGS including an IPP).However, currently the concerned RLDCs are providing the information related to Average Declared Capacity (DCi) of the CGS/ UMPPs only and not the IPPs despite such IPPs being duly qualified under the definition of ISGS under IEGC and such IPPs duly submitting the Declared Capacity to the concerned RLDCs on daily basis. As the result, based on the information furnished by the concerned RLDCs, the concerned RPCs are publishing the Plant Availability Factor (PAF) of the CGS/ UMPPs only, and not the IPPs in the monthly Regional Energy Accounts (REAs). Due to this, the concerned IPPs are facing challenges in receiving payments corresponding to Capacity Charges from their beneficiaries/ Discoms.

   MB Power (MP) Ltd. has proposed that the concerned RLDCs and RPCs may be directed to publish the Plant Availability Factor (PAF) of the IPPs (in addition to CGS/UMPPs) in the monthly REAs and

suitable amendments in the IEGC may be issued by the CERC to this effect.

3) The terms "original beneficiary" and "beneficiary" as referred to under draft amendments ofPart-6 may clearly defined under the heading "Definitions".

16.3 SJVN Limited has suggested certain amendments to Regulations 6.4.17, 6.5.12 and 5.2 (h) of the Grid Code.

PART-6 SCHEDULING AND DESPATCH CODE:

Clause 17:

16.3.1 Regulation 6.4.17 of the Grid Code provides as under:

"While making or revising its declaration of capability, except in case of Run off the River (with up to three hour pondage) hydro stations, the ISGS shall ensure that the declared capability during peak hours is not less than that during other hours. ***However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units <u>as a result of forced outage ofunits."</u>***

SJVNL has proposed that Regulation 6.4 (17) be modified as under:

However, exception to this rule shall be allowed in case of tripping/re-synchronisation of units/ as a result of forced outage of units or exigent conditions compelling ISGS to stop the unites)/station to prevent an imminent damage to a costly equipment in consultation with NRLDC.

SJVNL has submitted the following supporting arguments in favour of the proposed amendment:

(i) Two Power Projects of Himachal Pradesh viz 1500 MW NathpaJhakri Hydro Power Station (NJHPS) and 412 MW Rampur Hydro Power Station (RHPS) are located on Satluj River and attain peak discharge during summer from June to September every year due to melting of glacier. During this time. NJHPS operates continuously round-the-clock on account of large inflow/availability of water. During exceptional circumstances only, these two projects are sometimes forced to be put under shut-down due to reasons of high silt/ reservoir flushing or opening of silt flushing gate in NJHPS, or in the upstream hydro power projects such as Karcham Wangtoo Hydro Power Station (KWHPS). Such high silt/silt flushing/reservoir flushings are immediately intimated to NRLDC as per the provisions of the Grid Code.

(ii) The aforesaid phenomena of high silt/reservoir flushing is an event beyond the control of the generator and therefore shut-down of its generating units are required despite that the machines are available for generation. Such a shut-down is imminent to avoid any damage to the power plant/equipment and to prevent silt water entering into the tunnel beyond the permissible limit. The above event is not attributable to the generator and in such circumstances, the shut-down of the machines should be viewed as on account of water being not available for generation of electricity and not for any defect or deficiency in the machines or power plant system maintained by the generator.

16.3.2 Regulation 6.5.12 of the Grid Code provides as under:

"Clause 12. Run-of-river power station with pondage and storage type power stations are designed to operate during peak hours to meet system peak demand. Maximum capacity of the station declared for the day shall be equal to the installed capacity including overload capability, if any. minus auxiliary consumption, corrected for the reservoir level. <u>The Regional Load Despatch Centers shall ensure that generation schedules of such type of stations are prepared and the stations despatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints."</u>

SJVNL has proposed that the last sentence of Regulation 6.5.12 may be modified as under:

"The Regional Load Despatch Centers shall ensure that generation schedules of such type of stations are prepared and the stations despatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints/ tandem operation of projects to avoid spillage of water."

SJVNL has submitted the following supporting arguments in support of the proposed amendment:

(i) Rampur Hydro Power Station (RHPS) is being operated in tandem with the upstream project i.e. 1500(6 X 250) MW NathpaJhakri Hydro Power Station (NJHPS) and is dependent on the water released from the NJHPS. Satluj water is stored in the DAM/ Reservoir of NJHPS for its generation. RHPS is a unique generating station which does not have its own storage / pondage at all and is operating with water coming out from the Tail Race Tunnel of NJHPS. The water being used for generation in NJHPS is diverted into the Rampur intakes through the TRT pond. The discharge of water released from NJHPS is utilized by RHPS avoiding any spillage of water at TRT of NJHPS.

(ii) Due to tandem operation of aforesaid two projects, if for any reason, one unit of NathpaJhakri Project of250 MW is out of operation, the proportionate water cannot be utilised for generation of one unit of 68.67 MW of the Rampur Project. Although all the units of Rampur Project are fully available, but because of non-availability of water from the NathpaJhakri Project (due to non-availability of one unit of NathpaJhakri Project), water equivalent to one unit for Rampur HPS does not get released till such time the 250 MW of NathpaJhakri Project is brought back into operation. Similarly, if one unit of Rampur Project cannot be operated for any reason, the operation of all six unit(s) of NathpaJhakri Project and release of water for the purpose would result in the wasteful/spillage of water, due to not being utilised for generation of electricity by Rampur Project for the capacity of one unit of 68.67 MW.

(iii) In the peculiar facts and circumstances mentioned as above, SJVN Limited could be constrained in the national interest not to release the water for generation of electricity in both the NathpaJhakri Project and Rampur Project, under the circumstances where a unit of Rampur Project or the NathpaJhakri Project, as the case may be, is not available for generation of electricity, though the unit in the other project is available for generation and supply of electricity. Such a situation is for reasons other than those attributable to SJVN Limited and has been mandated on account of the utilisation of water of the Sutlej River to the maximum extent possible. The above arrangement is beneficial to the Procurers of electricity, especially during the lean season as the water of Sutlej river is stored in the reservoir/pondage maintained upstream of the NathpaJhakri Project and gets released only when the generation is possible at both NathpaJhakri Project and Rampur Project in tandem.

16.3.3 SJVNL Ltd. has submitted that the following para has been proposed to be added under Regulation 5.2 (h) of the Grid Code in the Draft Fifth Amendment:

*"For the purpose of ensuring sustainable primary response, RLDCs/SLDCs shall not schedule the generating units beyond ex bus generation corresponding to **<u>100% of the Installed capacity</u>***

SJVNL has proposed that the said para be substituted as under:

"For the purpose of ensuring sustainable primary response, RLDCs/SLDCs shall not schedule the generating units beyond ex bus generation corresponding to <u>100% of the Installed capacity except for optimum utilization of available hydro energy during high inflow season" …………</u>

SJVNL has submitted the following reasons for the proposed change:

(i) During high inflow season i.e. summer season from June to September due to glacier melting, water inflow in the Satluj River increases manifold, which is more than enough for generation of all its generating units of NJHPS and RHPS including overload capability. In Such circumstances, water is being spilled out from the reservoir/DAM of NathpaJhakri project, which is unavoidable and beyond the control of generator due to excess inflow, by opening of Dam gates. During such period, imposition of scheduling corresponding to Ex-bus installed capacity of plant/unit(s) for the purpose of ensuring sustainable primary response, would lead to more spillage of water which can be utilised by overloading of machine up to some extent.

(ii) During the high inflow season, when inflow in the reservoir is in excess of the design discharge round-the-clock, the generating units may operate on overload capacity to the extent of the capability of machine by utilising more water and thus leading to less spillage of water. The above scheme would not only be a prudent utility practice to be adopted but also in the national interest and more particularly in the interest of the Procurers. Thus, optimum utilization of water from the generating station can meet the power requirement of the Grid and thus overloading may be allowed during the peak season or for system requirements.

16.4 **Tata Power Trading Company Limited (TPTCL)** has submitted that Tariff Policy dated 28.01.2016,mandates that the URS not scheduled by the original beneficiaries of ISGSs shall be utilized by way of allowing the generator to sell the same through market. With regard to sale of URS power, CERC had issued Ancillary Services Operations Regulations, 2015 on 13th Aug 2015. Through, Reserve Regulation Ancillary Services (RRAS), URS can be utilized under Regulation up Services by responding to signal or instruction of Nodal Agency for increase in generation. Further, CERC has issued framework on Forecasting, Scheduling, Deviation Settlement and related matter for wind and solar generators. It is expected that in near future, grid has to face huge variation on account of scheduling of wind/solar power. TPTCL has submitted that System Operators need to maintain the security, safety and reliability of the grid all the time. In this regard, system requires adequate reserves to respond to real time variation in generation. As Deviation Settlement Mechanism is taking care of mismatch between schedule and actual generation/actual off take, it results in smooth grid operation by maintaining grid frequency in a narrow band. However, the variation in the grid frequency would increase once the wind and solar generators start scheduling their power. In such circumstances, URS can be utilized further and accordingly, the scope of existing provisions of Ancillary Services Regulations may be extended to balancing the market due to large variation in the schedule from actual generation of Wind/Solar generators. TPTCL has requested the Commission to kindly consider the balancing of the deviation of green power (Wind and Solar) through available URS.

Analysis and decision

We have noted the above suggestions of stakeholders. These suggestions have been noted and may be considered in merit for inclusion in the draft amendments to the Grid Code in future.

Sd/-	Sd/-	Sd/-
(M.K. Iyer) Member	(A.S. Bakshi) Member	(A.K. Singhal) Member

APPENDIX-I

Written Comments/Suggestions on

Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fifth Amendment) Regulation, 2016

S. No.	Company/Stakeholder/Individual
1.	Adani Power Limited (APL)
2.	Central Electricity Authority (CEA)
3.	Gujarat UrjaVikas Nigam Limited (GUVNL)
4.	GRIDCO Limited
5.	Indian Energy Exchange (IEX) Limited
6.	JSW Energy Limited
7.	Kerala State Electricity Board Limited (KSEB)
8.	M. B Power (M.P) Limited
9.	Maharashtra State Electricity Distribution Co. Ltd. (MSEDCL)
10.	M.P Power Management Company Limited (MPPMCL)
11.	NTPC
12.	Neyveli Lignite Corporation Limited (NLC)
13.	POSOCO
14.	Sterlite Power Transmission Limited (SPTL)
15.	Shri Vijay Menghani
16.	Southern Regional Power Committee (SRPC)
17.	SJVN Limited
18.	Tata Power Trading Corporation Limited (TPTCL)
19.	West Bengal Electricity Regulatory Commission (WBERC)

APPENDIX-II

Oral submissions /Power Point Presentation on

Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fifth Amendment) Regulation, 2016

S. No.	Company/Stakeholder/Individual
1	Indian Energy Exchange (IEX) Limited
2	M.P Power Management Company Limited (MPPMCL)
3	NTPC
4	POSOCO
5	Shri Vijay Menghani