CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram:
ShriGireesh B.Pradhan, Chairperson
ShriA.K.Singhal, Member
Shri A.S. Bakshi, Member
Dr. M.K. Iyer, Member

Date: 6th April, 2016

STATEMENT OF REASONS

Subject: Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016

1. General

1.1 The Commission through public notice on 2.7.2015 floated on its web site the draftofthe Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2015and invited comments of the stakeholders by 24.7.2015.

1.2 The Draft Regulations provide for the procedure and mechanism for declaration of commercial operation of the inter-State generating stations and technical minimum schedule for operation of inter-State generating stations.

1.3 Commission also came out with a supplementary Draft Regulation providing for the procedure and mechanism for declaration of commercial operation of the inter-State transmission system inviting comments from stakeholders by 3.8.2015.

1.4 About 27stakeholders including Central Generating Companies, State Discoms,IPPs, POSOCO, etc., submitted their valuable comments/suggestions. List of stakeholders is enclosed as Annexure-I. Apart from above, Power Grid, Adani Power Ltd, and Sterlite Power Grid venture Ltd has also given their comments/suggestions on the supplementary draft Regulations. Commission also held the public hearing on 19.8.2015.

1.5 The comments, suggestions and objections received on the draft regulations have been considered in the succeeding paragraphs.

2. Regulation 6.2 of the Grid Code:

2.1 It was proposed to amend Regulation 6.2 of the Grid Code to include in the Objectives the new provisions like declaration of commercial operation, trial operation and technical minimum schedule for operation of generating stations. The draft amendment read as under:

> "This code also provides for the procedure and mechanism for declaration of commercial operation of the inter-State generating stations and technical minimum schedule for operation of inter-State generating stations."

2.2 **Comments received:**

The MPSLDC has submitted that the Regulation should also provide for mandating COD declaration by generating station whose scheduling is done as per Regulation 6.4.2 of IEGC. POSOCO has submitted that the Regulation should be applicable to all generating stations and not only to ISGS. Further, it may be clarified that thermal includes combined cycle plants also. Regulation should also provide for COD of RE generating resources such as wind, solar etc.

2.3 **Analysis and Decision**

2.3.1 As per IEGC, the "Inter-State Generating Station (ISGS)" means a Central generating station or other generating station, in which two or more states have Shares.

2.3.2 The Regulation 6.4.2 of the IEGC provides as follows:

"The following generating stations shall come under the respective Regional ISTS control area and hence the respective RLDC shall coordinate the scheduling of the following generating stations:

a) Central Generating Stations (excluding stations where full Share is allocated to host state),

b) Ultra-Mega power projects

(c) In other cases, the control area shall be decided on the following criteria:

(i) If a generating station is connected only to the ISTS, RLDC shall coordinate the scheduling, except for Central Generating Stations where full Share is allocated to one State.

(ii) If a generating station is connected only to the State transmission network, the SLDC shall coordinate scheduling, except for the case as at (a) above.

(iii) If a generating station is connected both to ISTS and the State network, scheduling and other functions performed by the system operator of a control area will be done by SLDC, only .if state has more than 50% Share of power, The role of concerned RLDC, in such a case, shall be limited to consideration of the schedule for interstate exchange of power on account of this ISGS while determining the net drawal schedules of the respective states. If the State has a Share of 50% or less, the scheduling and other functions shall be performed by RLDC.

(iv) In case commissioning of a plant is done in stages the decision regarding scheduling and other functions performed by the system operator of a control area would be taken on the basis of above criteria depending on generating capacity put into commercial operation at that point of time. Therefore it could happen that the plant may be in one control area (i.e. SLDC) at one point of time and another control area (i.e. RLDC) at another point of time. The switch over of control area would be done expeditiously after the change, w.e.f. the next billing period."

2.3.3 It may be seen that some of the Central generating stations supplying 100% power to one State which are not covered by the definition of ISGS may not get covered in the scope. Since the tariff of Central generating stations are regulated by CERC, it is felt that central generating stations which are not ISGS may also be included in the scope. The State generating stations would be out of scope as far as declaration of COD is concerned. However, it is up to the State Electricity Regulatory Commission to extend these provisions in respect to State generating stations in their purview through suitable provisions in the respective State Grid Code.

2.3.4 The mechanism of declaration of COD and trial operation is specific to thermal and hydro generating stations. We appreciate the concern of POSOCO that there should be provision for generating stations of renewable energy sources such as wind, solar and others. The Commission may come out with suitable provision in due course. So far as applicability of these provisions to combined cycle plants is concerned, the same being a variant of the thermal generating stations, these provision shall apply to such generating stations as well.

2.3.5 Further, it is also considered necessary to provide for the procedure and mechanism for declaration of commercial operation of the inter-State transmission system and assets thereof.

2.3.6 In view of the above, Regulation 6.2 of the Grid Code has been amended to include the following:

> "This code also provides for the procedure and mechanism for declaration of commercial operation of the Central Generating Stations, inter-State Generating Stations and the inter-State Transmission System and technical minimum schedule for operation of Central Generating Stations andinter-State Generating Stations."

3. **Regulation 6.3 of the Grid Code:**

3.1 The following regulations were proposed to be inserted through the amendment with regard to commercial operation of the generating stations.

"6.3A Commercial operation of inter-State Generating Stations

"1. Date of commercial operation in case of a unit or block of thermal generating station shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its Maximum Continuous Rating (MCR) or the Installed Capacity (IC) or Name Plate Rating on designated fuel through a successful trial run and after getting clearance from the respective RLDC or SLDC, as the case may be, and in case of the generating station as a whole, the date of commercial operation of the last generating unit or block of the generating station:

Provided that

(i) Where the beneficiaries / buyers have been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries/buyers and concerned RLDC or SLDC, as the case may be.

(ii) Where the beneficiaries / buyers have not been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to the concerned RLDC or SLDC, as the case may be.

(iii) The generating company shall certify that:

(a) The generating station meets the relevant requirements and provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and Indian Electricity Grid Code, as applicable:

(b) The main plant equipment and auxiliary systems including Balance of Plant, such as Fuel Oil System, Coal Handling Plant, DM plant, pre-treatment plant, fire-fighting system, Ash Disposal system and any other site specific system have been commissioned and are capable of full load operation of the units on sustained basis.

(c) Permanent electric supply system including emergency supplies and allnecessary instrumentation, control and protection systems and auto loopsfor full load operation of unit have been put in service.

(iv) The certificates as required under clause (iii) above shall be signed by CMD/CEO/MD of the company and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and the concerned RLDC/ SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required under clause (iii) within a period of 3 months of the COD.

(v) Trial run shall be carried out in accordance with sub-Regulation 6.3A.3 of this Regulation.

(vi) Partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating or the Installed Capacity or the Name Plate Rating.

(vii) For declaration of COD, the unit capacity demonstrated during trial run shall not be less than 95% of the name plate rating or the contracted capacity provided unit is de-rated by the generating company to a capacity corresponding to and considering grid response to 105% of the capacity so de-rated in terms of IEGC.

(viii) Respective Load Despatch Centre shall accord clearance for declaration of COD within 7 days of receiving the generation data based on the trial run.

(ix) If RLDC/SLDC notices any deficiencies in the trial run, it shall be communicated within seven days.

(x) Scheduling shall commence from 0000 hrs after completion of trial run from date to Commercial Operation of the unit.

3.2 Date of Commercial Operation (COD) in relation to a generating unit of hydro generating station including pumped storage hydro generating station shall mean the date declared by the generating company after demonstrating peaking capability corresponding to the Installed Capacity of the generating station through a successful trial run, and after getting clearance from the respective RLDC/SLDC, as the case may be, and in relation to the generating station as a whole, the date of commercial operation of the last generating unit of the generating station.

Provided that:

(i) Where beneficiaries have been tied up for purchasing power from the generating station, trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and concerned RLDC or SLDC as the case may be;

(ii) Where the beneficiaries/buyers have not been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to concerned RLDC/ SLDC, as the case may be.

(iii) The generating company shall certify that:

(a) The generating station meets the relevant requirement and provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Indian Electricity Grid code as applicable:

(b) The main plant equipment and auxiliary systems including Drainage De-watering system, Primary and Secondary cooling system, LP and HP air compressor, Fire-fighting system, etc., have been commissioned and are capable for full load operation of units on sustained basis.

(c) Permanent electric supply system including emergency supplies and all necessaryInstrumentations, Control and Protection systems and auto loops for full load operation of unit are put in service.

(iv) The certificates as required under clause (iii) above shall be signed by CMD/CEO/MD and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and concerned RLDC or SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required under clause (iii) within a period of 3 months of COD.

(v) Trial run shall be carried out in accordance with sub-Regulation 6.3A.3 of this Regulation.

(vi) For declaration of COD, the unit Capacity demonstrated during trial run shall not be less than 95% of the name plate rating provided unit is de-rated by the generating company to a capacity corresponding to and considering grid response to 110% of the capacity so de-rated in terms of IEGC.

(vii) In case a hydro generating station with pondage or storage is not able to demonstrate peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the date of commercial operation of the last unit of the generating station shall be considered as the date of commercial operation of the generating station as a

whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating unit or the generating station as and when such reservoir/pond level is achieved:
(viii) If a run-of-river hydro generating station or a generating unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or generating unit to demonstrate peaking capability equivalent to installed capacity as and when sufficient water inflow is available. In case of failure to demonstrate the peaking capacity the unit capacity shall be de-rated to the capacity demonstrated.

(ix) Respective Load Dispatch Centre shall accord clearance within 7daysof receiving the generating data based on the trial run.

(x) If RLDC/ SLDC notices any deficiency in trial run, it shall be communicated within 7 days.

(xi) Scheduling shall commence from 00:00 hrs after completion of trial run from date of Commercial Operation of the unit.

3.3 Trial Operation or Trial Run-Trial Operation or Trial Run in relation to a thermal generating station or a unit thereof shall mean successful running of the generating station or unit thereof on designated fuel at Maximum Continuous Rating or Installed Capacity or Name Plate Rating or the De-rated Capacity for continuous period of 72 hours and in case of a hydro generating station or a unit thereof for a continuous period of 12 hours:

Provided that the short interruptions, for a cumulative duration of 4 hours, shall be permissible, with corresponding increase in the duration of the test. Cumulative Interruptions of more than 4 hours shall call for repeat of trial operation or trial run.

Provided further that partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating, or the Installed Capacity or the Name Plate Rating.

Provided that where the beneficiaries have been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries."

3.4. In the event of inconsistency between the provisions relating to trial and commercial operation as specified in Sub-Regulation 6.3A.1 to 6.3A.3 of these regulations and the provisions in Central Electricity Regulatory Commissions (Terms and Conditions of Tariff) Regulations, 2014, the provisions of these regulations shall prevail."

3.2 Comments received:

3.2.1 Tata Power has submitted that the inability to run at full load may be due to non-availability of Load/ Grid Capacity. De-rating may not be appreciated. In case the full capacity is not tied up then it should be responsibility of the RLDC to ensure that the specified condition of running at Maximum Continuous Rating (MCR)/ Installed Capacity/ Nameplate Rating is met.

3.2.2 NTPC, NLC, GRIDCO and POSOCO has submitted that the **p**rocedure for declaration of COD and technical minimum are very relevant and a welcome step. They have no objection for demonstration of MCR or the installed capacity or the Nameplate rating on designated fuel. POSOCO has also submitted that overload capacity should also be demonstrated.

3.2.3 The APP and Adani Power has submitted that **t**he capacity demonstrated should be 90 % of rated capacity on an average basis for the period of trial run instead of at MCR or Installed capacity.

3.2.4 The draft Regulation provides for de-rating to a capacity considering grid response to 105% of capacity de-rated. In this regard APP and Tata Power has submitted thatthe requirement of over capacity of 5 % in proposed Amendment 6.3 A (1) (vii) is on higher side. It may be reduced to 3%.

3.3 Analysis and Decision

3.3.1 The Commission on the issue of capacity to be tested has observed in the Explanatory Memorandum as follows:

> "Capacity to be Tested
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> 15. Itmaybeseenfromtheprovisionswithregardto COD of a unit of a generating station in different Regulations, OMs, PPAs and procedure followed by NTPC that emphasis is on demonstration of Maximum Continuous Rating of the unit or Installed Capacity or the Nameplate Rating or the contracted capacity. But declaration of COD in case of UMPP projects and Competitive bid projects in Case II on DBFOT basis is based on demonstration of 95% of Installed capacity or more.
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> 16. However, it is felt that from the point of view of the beneficiaries / procurers and the grid operation point of view, the capacity demonstrated should be MCRcapacity or the Installed Capacity or the name plate rating and not less than this. Insuch a situation it may

not be desirable to provide for declaration of COD for thedemonstration of capacity less than the installed capacity or the contracted capacity.However, it is up to the generating company to de-rate the unit which should not beless than 95% of the name plate rating or the contracted capacity and with corresponding de-rating of unit considering grid response to 105% of the capacity sode-rated in terms of IEGC. In such case of de-rating, RLDC should accept COD afterdemonstration of capacity to such de-rated capacity. The UMPP PPAs will have to bealigned to this particular provision."

3.3.2 In our view, the capacity intended originally which is reflected in theMaximum Continuous Rating of the unit or Installed Capacity or the Name Plate Rating only needs to be established and demonstrated before declaring the COD of any unit. This is desirablefrom the point of view of the beneficiaries / procurersand the grid operation.However, to take care of the concerns of the generator that its unit is not rejected for demonstrating capacity less thanMCRcapacity or the Installed Capacity or the name plate rating, the COD declaration may be allowed at capacity less than MCRcapacity or the Installed Capacity or the name plate rating subject to de-rating of the unit by the generator. This would howeverbe with a rider that such demonstration of capacity should not be less than 95% of the MCRcapacity or the Installed Capacity or the name plate rating. The de-rated capacity may however, be less than 95% of MCRcapacity or the Installed Capacity or the name plate rating in due consideration of providing primary response and meeting IEGC stipulation of 5.2 (h) of instantaneously picking up 105% for Thermal & 110 % for Hydro of such de-rated capacity instead of MCR.

4. Trial Run of the units of generating stations

4.1 The Draft Regulations provided for Trial Run for a period of 72 hours for trial operation and also provide for partial loading with the corresponding extended period of trial operation with the condition that average loading is not less than MCR or Installed Capacity or name plate rating.

4.2 Comments received:

4.2.1 GRIDCO has submitted that as per Clause 2.2 of IS-8595-1977 (Reaffirmed 2012) Terminology of parameters of Stationary Steam Boilers) Maximum Continuous Rating

(MCR) has been defined as maximum steam output in tones/ hour (gross) which the boilers should give continuously for not less than 72 hours while maintaining the specified values of basic parameters. Accordingly, duration of test should be for continuous period of 72 hours without any interruption or without any partial loading.

4.2.2 APP, TATA Power and NTPC has submitted that a suitable provision may be included to address interruptions on account of reasons beyond the control of the generator. If the unit is not able to run at Maximum Continuous Rating (MCR) for the specified time period of 72 hours due to non-availability of load and grid constraints then such unit be considered for deemed COD. The system operator may ask such unit to demonstrate its performance later if they believe that unit is operating below par. The period of 4 hours may be allowed to extend appropriately based on the actual experience.

4.2.3 POSOCO has submitted that the hydro station shall demonstrate the peaking capability within one year from date of COD and share data regarding pondage& peaking capability at various level of water inflows with RLDC/SLDC.

4.2.4 TATA Power and NTPC have further submitted that it may not be possible for the generating company to meet the requirements of provision of partial loading that the average load during the duration of trial run shall not be less than Maximum Continuous Rating (MCR) of the Installed Capacity or the Nameplate Rating. Further, this would require running of unit on overload for a prolonged period which may not be desirable.

4.2.5 NLC has submitted that the average loading during the duration of trial run should be worked out excluding the period of interruptions.

4.3 Analysis& Discussion

4.3.1 The Commission in theExplanatory Memorandum has observed as follows:

"Duration of Test and treatment of Interruptions during the trial operation

17. The other issue is the duration of capacity test before declaring COD. All Regulations and PPA provisions etc provide for trial run of 72 hour continuous operation except the MoP OM dated 9.9.2009 which provide for achieving full load of unit or name plate rating without specifying the period of sustaining load continuously. However aforementioned MoP OM is for the purpose of commissioning of a unit/ station and not for its commercial operation. No specific genesis for 72 hour continuous trial run has been found but perhaps this is from the point of view of establishing sustained operation of the unit. However, it is found that industry is not following the practice of 72 hour trial operation continuously at rated capacity or name plate rating or 95% of the capacity and the name plate rating in letter and spirit.

18. As per procedure followed by NTPC, during trial run, minor interruptions (less than 4 hours at a time) do not affect the duration of trial run. If the interruption-outage is long (more than 4 hours), the trial run is prolonged for the period of interruption. Minor partial loading is allowed, but the average load during the running hours has to be equal to the Installed Capacity.

19. From the practical point of view as well, sustaining unit load at the rated capacity or the name plate rating may always not be possible throughout 72 hour due to various reasons such as low system demand during off peak hours, system constraints, unit partial loading due to operational reasons, etc. From the commercial point of view, retesting would involve extra cost. It may therefore, be desirable that short interruptions may be allowed with a cumulative of 4 hours during 72 hour testing with corresponding increase in total duration of test. Cumulative interruptions of more than 4 hours would call for retesting. Further partial loading may be allowed with the condition that average load (based on 15 minute SEM readings) during the duration of the trial run shall not be less than Maximum Continuous Rating, or the Installed Capacity or the name plate rating."

4.3.2 According to GRIDCO, there is genesis of trial operation for the continuous period of 72 hours as per IS-8595-1977 (Reaffirmed 2012 and no partial loading or interruptions should be allowed. Whereas we agree in principle that as far as possible the trial operation should be for continuous period of 72 hours but the question is whether trial operation should be repeated all the time if the generator is unable to operate continuously for 72 hours at its MCR rating due to various unavoidable reasons not within his control. However, considering the large size of integrated grid, large capacity addition envisaged of large size units, integration of renewable sources of energy into the grid, low system demand during off peak hours, ensuring load corresponding to the MCR or Installed Capacity or name plate rating may be difficult and it may not be desirable practically and commercially to prolong the COD of unit unduly. Commission therefore, deem it fit to provide for short interruptions and partial loading for a cumulative period of 4 hours with corresponding increase in duration of trial operation. Any cumulative period of partial loading and interruption of more than 4 hours will require repeat of trial operation for a further period of 72 Hours.

4.3.3 Apart from above, there was provision that the average capacity demonstrated should not be less than MCR or Installed Capacity or the nameplate rating during the period of testing. There is merit in the contention of APP, Tata Power and NTPC that this would require loading of unit more than MCR or Installed Capacity or the nameplate rating and would be difficult. It is therefore, provided that average unit loading may be worked out after excluding the period of partial loading and interruptions but including the extended period of operation.

4.3.4 However, it is necessary that the unit will have to comply with IEGC provision of Regulation 5.2 (h) and demonstrate its capability of instantaneously picking up to 105% of MCR in case of thermal units and 110% of the MCR in case of hydro units. This capability shall also be demonstrated during the trial operation/trail run.

5. Certification of Meeting Technical Requirements

5.1 The Draft Regulations provide for certification by Generating company that generating station meets the relevant requirements and provision of CEA Technical standards and IEGC duly approved by Board of Directors of the Company.

5.2 Comments received

5.2.1 APP has submitted that the Certificate of meeting the relevant requirements and provision of technical standards of CEA (Technical standards for construction of electrical plants and electric line) Regulations, 2010 should be applied prospectively**.**

5.2.2 NRPC has submitted that Authority has specified Regulations covering aspect such as safety, construction, metering, Grid connectivity, O&M, etc. Therefore, amendment should include general reference to meeting of various Regulations specified by Authority and Central Commission.

5.2.3 NTPC has submitted that Certification as proposed in 6.3A.1 (iii) may not be insisted upon. The decision to declare COD after trial run and its assessment may be left to the generator and clearance communication from RLDC before such declaration may not be insisted upon.

5.2.4 NHPC has submitted that the certificate may be submitted with the approval of CMD instead of Board of Directors.

5.2.5 NLC has submitted that the 100% availability of Balance of Plant and other systems before full load of operation will be a difficult proposition and may not be insisted upon.

5.2.6 APP and Tata Power have submitted that the commissioning of all control loops as mentioned in 6.3A.1 (iii)(c) be relaxed as the tuning requires operation of unit for some months depending on certain site specific condition.

5.2.7 POSOCO has submitted that there is a need to add CEA (Technical standard for connectivity to the Grid) Regulations for compliance before declaration of COD. It could not be possible for RLDC to clarify part completion of communication system.

5.3 Analysis and Decision

5.3.1 We have considered the submission of the stakeholders. We are unable to accept the suggestion except to the extent that the requirements of CEA (Technical standard for connectivity to the Grid)Regulations may also be met.

5.3.2 The Commission has consciously provided for the certification by the generator before COD declaration in the specified manner in due consideration of recommendations of CEA and POSOCO to ensure sustained operation of plant meeting system requirements and availability of power for the beneficiaries as brought out in Explanatory Memorandum. As such, we are retaining the provision with minor modification.

6. Furnishing of Information regarding Trial Operation & Generation data

6.1 The Draft Regulations provide for submitting generation data to RLDC/SLDC. POSOCO has submitted that submission of information shall also be made to RPCs in addition to RLDCs.

6.2 **Decision:** At present the POSOCO forwards all generation related data to RPCs and the same practice may be followed in case of declaration of COD also.

7. Start of COD

7.1 The Draft Regulation provide for scheduling to start from 0.00 Hr after trial operation.

7.2 POSOCO has submitted that the scheduling should start from 0.00 Hr after declaration of COD which is accepted.

7.3 Decision: Suggestion of POSOCO has been accepted and necessary modification has been done to the regulations.

8. Notice Period

8.1 The Draft Regulations provide for 7 day prior notice for trial operation.

8.2 **Comments received:** NHPC has submitted that the Notice Period may be reduced to 3 days. NLC has submitted to reduce the notice period to 1 day. NTPC has submitted that no notice should be required for retesting. POSOCO has submitted that fresh notice is to be given, in case of postponement of trial operation.

8.3 **Decision**: The Commission is of the view that 7 days prior notice for every trial operation including retesting is reasonable and accordingly, has been retained.

8.4 In view of the above discussion, Sub-Regulation 6.3A has been modified as:

"6.3A Commercial operation of Central generating stations and inter-State Generating Stations

1. Date of commercial operation in case of a unit of thermal Central Generating Stations or inter-State Generating Station shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its Maximum Continuous Rating (MCR) or the Installed Capacity (IC) or Name Plate Rating on designated fuel through a successful trial run and after getting clearance from the respective RLDC or SLDC, as the case may be, and in case of the generating station as a whole, the date of commercial operation of the last unit of the generating station:

Provided that:

(i) Where the beneficiaries / buyers have been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries/buyers and concerned RLDC or SLDC, as the case may be.

(ii) Where the beneficiaries / buyers have not been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the concerned RLDC or SLDC, as the case may be.

(iii) The generating company shall certify that:

(a) The generating station meets the relevant requirements and provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and Indian Electricity Grid Code, as applicable:

(b) The main plant equipment and auxiliary systems including Balance of Plant, such as Fuel Oil System, Coal Handling Plant, DM plant, pre-treatment plant, fire-fighting system, Ash Disposal system and any other site specific system have been commissioned and are capable of full load operation of the units of the generating station on sustained basis.

(c) Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of unit have been put in service.

(iv) The certificates as required under clause (iii) above shall be signed by the CMD/CEO/MD of the generating company and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and the concerned RLDC / SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required under clause (iii) within a period of 3 months of the COD.

(v) Trial run shall be carried out in accordance with Regulation 6.3A.3 of these Regulations.

(vi) Partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating or the Installed Capacity or the Name Plate Rating excluding period of interruption and partial loading but including the corresponding extended period.

(vii) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to Maximum Continuous Rating or Installed Capacity or Name Plate Rating, the generating company has the option to de-rate the capacity or to go for repeat trial run. Where the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 105% of de-rated capacity.

(viii) The concerned RLDC or SLDC, as the case may be, shall convey clearance to the generating company for declaration of COD within 7 days of receiving the generation data based on the trial run.

(ix) If the concerned RLDC or SLDC, as the case may be, notices any deficiencies in the trial run, it shall be communicated to the generating company within seven (7) days of receiving the generation data based on the trial run.

(x) Scheduling of power from the generating station or unit thereof shall commence from 0000 hrs after declaration of COD.

2. Date of commercial operation (COD) in relation to a generating unit of hydro generating station including pumped storage hydro generating station shall mean the date declared by the generating company after demonstrating peaking capability corresponding to the Installed Capacity of the generating station through a successful trial run, and after getting clearance from the respective RLDC or SLDC, as the case may be, and in relation to the generating station as a whole, the date of commercial operation of the last generating unit of the generating station.

Provided that:

(i) Where beneficiaries have been tied up for purchasing power from the generating station, trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and concerned RLDC or SLDC, as the case may be;

(ii) Where the beneficiaries/buyers have not been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to concerned RLDC or SLDC, as the case may be.

(iii) The generating company shall certify that:

(a) The generating station or unit thereof meets the requirement and relevant provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and Indian Electricity Grid Code, as applicable:

(b) The main plant equipment and auxiliary systems including Drainage Dewatering system, Primary and Secondary cooling system, LP and HP air compressor, Firefighting system, etc. have been commissioned and are capable for full load operation of units on sustained basis.

(c) Permanent electric supply system including emergency supplies and all necessary Instrumentations Control and Protection Systems and auto loops for full load operation of the unit are put into service.

(iv) The certificates as required under clause (iii) above shall be signed by the CMD/CEO/MD of the generating company and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and concerned RLDC or SLDC, as the case may be, before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required under clause (iii) within a period of 3 months of COD.

(v) Trial run shall be carried out in accordance with sub-Regulation 6.3A.3 of this Regulation.

(vi) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to Maximum Continuous Rating or Installed Capacity or Name Plate Rating, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 110% of de-rated capacity.

(vii) In case a hydro generating station with pondage or storage is not able to demonstrate the peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the date of commercial operation of the last unit of the generating station shall be considered as the date of commercial operation of the generating station as a whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating station or unit thereof as the case may be, as and when such reservoir/pond level is achieved:

(viii) If a run-of-river hydro generating station or a unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or unit thereof to demonstrate peaking capability equivalent to installed capacity as and when sufficient water inflow is available. In case of failure to demonstrate the peaking capacity, the unit capacity shall be de-rated to the capacity demonstrated with effect from the COD.

(ix) The concerned RLDC or SLDC as the case may be, shall accord clearance to the generating company within seven (7) days of receiving the generation data based on the trial run.

(x) If the concerned RLDC or SLDC as the case may be, notices any deficiency in trial run, it shall be communicated to the generating company within seven (7) days of receiving the generation data based on trial run.

(xi) Scheduling shall commence from 0000 hrs after declaration of COD.

3. Trial Run or Trial Operation: Trial Run or Trial Operation in relation to a thermal Central Generating Station or inter-State Generating Station or a unit thereof shall mean successful running of the generating station or unit thereof on designated fuel at Maximum Continuous Rating or Installed Capacity or Name Plate Rating for a continuous period of 72 hours and in case of a hydro Central Generating Station or inter-state Generating Station or a unit thereof for a continuous period of 12 hours:

Provided that:

(i) The short interruptions, for a cumulative duration of 4 hours, shall be permissible, with corresponding increase in the duration of the test. Cumulative Interruptions of more than 4 hours shall call for repeat of trial operation or trial run.

(ii) The partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating, or the Installed Capacity or the Name Plate Rating excluding period of interruption and partial loading but including the corresponding extended period.

(iii) Where the beneficiaries have been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and concerned RLDC or SLDC, as the case may be.

(iv) Units of thermal and hydro Central Generating Stations and inter-State Generating Stations shall also demonstrate capability to raise load upto 105% or 110% of this Maximum Continues Rating or Installed Capacity or the Name Plate Rating as the case may be."

9. Declaration of Commercial Operation of Transmission Systems:

9.1 Draft Regulations provided for the following with respect to the declaration of commercial operation of transmission system or its elements:

"6.3A.5. Date of commercial operation in relation to a transmission system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end:

Provided that:

(i) where the transmission line or substation is dedicated for evacuation of power from a particular generating station, the generating company and transmission licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement.

(ii) In case a transmission system or an element thereof is prevented from regular service for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned upstream or downstream transmission system, the transmission licensee shall approach the Commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof.

(iii) Provided that an element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as agreed in the Standing Committee of Transmission System Planning or as provided in the TSA, have been declared to have achieved their respective COD.

6. Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a communication system or element thereof is put into service after completion of site acceptance test including transfer of voice and data to respective control centre as certified by the respective Regional Load Dispatch Centre.

7. Trial run and Trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at continuous flow of power, and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system in service enclosing certificate to that effect from concerned Regional Load Dispatch Centre."

9.2 Comments received:

9.2.1 Adani Power limited: Since COD is an important factor for dealing with the date of commencement of tariff, the provisions relating to COD should have allowed continuing in the Tariff Regulations. By incorporating the said definition in Grid Code and overriding the same in the Tariff Regulations, 2014 would defeat the basic purpose of such definition. Moreover, COD of competitively bid projects cannot be included in the Grid Code and the same cannot override the provisions in competitive bidding guidelines issued by Ministry of Power, Government of India under Section 63 of the Electricity Act, 2003. The Commission might not have taken cognisance of the Policy dated 15.5.2015 incentivising the early commissioning of the transmission projects, mainly under Section 63 of the Electricity Act, 2003, by allowing actual COD prior to the Scheduled COD. The objective of MOP Policy is being defeated by the proposed amendment in the definition of COD of a Transmission system. Therefore, the amendment, if any, proposed by the Commission has to be in consonance with any of the policy notified by the Central Government.

Further, the Commercial operation Date of any Transmission System under the competitive bidding guidelines shall be reckoned based on its SCOD and it has nothing to do with the commissioning of the associated transmission systems. The proposed amendment through IEGC alters the said provision, which is not appropriate. Proviso (ii) and proviso (iii) of the proposed amendment are contradictory to each other. While Proviso (ii) of the proposed amendment provides for early declaration of COD of a transmission system in case the same is prevented to do so for reasons not attributable to it or its suppliers or contractors, Proviso (iii) provides for declaration of COD only after all pre-required transmission systems are commissioned. It is suggested that Proviso (iii) may be deleted.

9.2.2 **Sterlite Power Grid Ventures Limited**: While the purpose of introducing the above changes in proviso (ii) above are clear, there is a need to ensure that the proposed changes are consistent with the stipulations contained in the Competitive Bidding Guidelines and the Transmission Services Agreement (TSA) entered into as per the bid documents. These provide for the effective date of the tariff payment to a Transmission Licensee even in cases where the transmission elements or facilities of others are not ready upon the Transmission Licensee giving 7 days' notice (Para 6.2.1 of the TSA).Further in proviso (iii), there have been situations where the dependent transmission element cannot be completed for force majeure or other reasons not attributable to the Transmission licensee. In such a case CTU should have the power to use the lines constructed and capable of being put to regular service for other purposes as a part of the integrated grid system and the Transmission licensee should not be deprived of the tariff.Sterlite has suggested modifying Clause 6.3A.5 of the proposed amendment as under:

> "5. Date of commercial operation in relation to a transmission system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end:
>
> Provided that:

(i) Where the transmission line or substation is dedicated for evacuation of power from a particular generating station, the generating company and transmission licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement:

(ii) In case a transmission system or an element thereof is prevented from regular service for reasons not attributable to the transmission licensee or its supplier or its contractor but is on account of the delay in commissioning of the concerned upstream or downstream transmission system, the transmission licensee shall be entitled to treat the date of commercial operation of such transmission system or element thereof and claim tariff from the date and in the manner provided in the Transmission Service Agreement but shall approach the Commission through an appropriate application for approval of such date of commercial operation of such transmission system or an element thereof.

(iii) Provided that an element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as agreed in the Standing Committee of Transmission System Planning or as provided in the TSA, have been declared to have achieved their respective COD, unless otherwise decided by the Commission in cases where the non-completion of such pre required elements is not for any failure or factor attributable to the concerned transmission licensee."

9.2.3 **Power Grid Corporation of India Limited**:

9.2.3.1 In the proposed amendment, certain provisions of Tariff Regulations, 2014 have been deleted. In proviso (i), the words "....in accordance with Regulation 12(2) of these Regulations:" and in proviso (ii) the words "on account of delay in commissioning of the concerned Generating station or …." are deleted. It is submitted that prior to Connectivity Regulations, 2009, implementation of dedicated transmission system was the responsibility of the respective generators. In the Connectivity Regulations, 2009, the Commission included the dedicated transmission line as part of coordinated planning for generators having more than specified capacity. For implementation of dedicated line including transmission system strengthening, if required, Construction Bank Guarantee of only Rs.5 lakh/MW was also provided in the Regulations, which is very less compared to the cost of the Transmission line. Based on above provisions in the Connectivity Regulations, 2009, dedicated transmission lines for some IPPs are under implementation/ have been implemented by POWERGRID/under TBCB after taking regulatory approval from the Commission. In an effort to match the commissioning of dedicated transmission lines with that of generator, POWERGRID is continuously coordinating with the Generators regarding their progress. However, it has been seen that some of the Generators are inordinately delayed or are abandoning the projects despite their continuous insistence for materialisation of their generation as per indicated time schedule. After award of the contract for transmission line, it is not possible to inordinately delay the commissioning of assets due to contractual obligations. The Commission while appreciating these uncertainties in the commissioning of the Generators, had kept following provision in the Tariff Regulations, 2014:

> "4(3(ii)) in case a transmission system or an element thereof is prevented from regular service for reasons not attributable to the transmission licensee or its supplier or its contractors but is **on account of delay in commissioning of the concerned Generating station or** concerned upstream or downstream transmission system, the transmission licensee shall approach the commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof."

In view of the above premises, it is submitted that the provisions as provided in CERC Tariff Regulations, 2014 regarding delay in generators may be maintained.

9.3.2.2 In the Staff Paper on Transmission Planning, Connectivity, Long /Medium Term Open Access and other related issues, The Commission has also appreciated that the transmission should lead the Generation to avoid congestion or bottling up of power. With the proposed amendments, the onus of commissioning the transmission line matching with the generation lies mainly on the POWERGRID/ transmission licensee. In absence of provision of adequate construction BG, this shall increase the financial risk of the transmission companies and no transmission company shall be willing to implement dedicated transmission system, leading to bottling up of power.To address the issue, it is proposed that in future all the dedicated lines may be developed by the respective Generators. This will avoid the coordination issues between the Transmission licensees and Generators. As far as the dedicated Transmission systems which are under implementation as per provisions of Connectivity Regulations are concerned, their tariff may be included under POC mechanism after their commissioning as per agreed schedule irrespective of commissioning of Generators. The transmission charges for such lines should be shared by all DICs.

9.3.2.3 To fulfil the obligations of the generator towards transmission charges for the line, it is proposed that a separate bill for applicable transmission charges should be raised on such generators and the payment received from generators should be passed on to DICs. In case of non-payment by the generator, the connectivity/Access granted to such Generator may be cancelled and it will not be entitled for any power interchange with the Grid till clearing of all the outstanding dues.

9.3.2.4 Regarding projects under Tariff Based Competitive Bidding (TBCB), the definition of Commercial Operation Date (CoD) has been provided in the Pre-signed Transmission Service Agreement (TSA) and the same has also been reiterated by the Bid Process Coordinator in various clarification meetings.As the transmission system is established under Build, Own, Operate and Maintain (BOOM) basis as defined in the TSA along with the specific date / time period considering which the bidding is done, the provisions of the TSA are to prevail. In case any new conditions of CoD are warranted, the same may have to be incorporated in the bidding documents for the forthcoming projects before receipt of bids.

9.3.2.5 The bidders cannot be burdened with the risk of entering into an Implementation Agreement with the Generator and more so meet the requirement to match the generation schedule.The bidder under TBCB is governed to deliver the system as per the dates and provisions of the TSA. As per the TSA, the right to declare deemed CoD vests with the transmission system developer on meeting the defined conditions. As such the provisions of the TSA are to prevail wherein the transmission charges are payable after the CoD/Deemed CoD and is not dependent on the commissioning of generators or otherwise.

9.3.2.6 As regards proviso (iii) to Clause 6.3A.5, a transmission scheme comprises of number of elements i.e. Substations and Transmission lines. A transmission line can exist between two substations embedded in the Grid, thus becomes part of interconnected system on its commissioning irrespective of other elements in the scheme. In a complex grid, availability of each element increases reliability of the Grid.Further, a transmission project comprising of several transmission elements may be awarded to various Transmission Licensees. However, during the execution stage, some of the elements may get delayed due to Right of Way or other issues. In such scenario it is not prudent to penalize the other Licensee/Agency who has completed its scope within the given timeframe.Thus, the elements of a project which are put up under commercial operation as per their initial schedule and supporting the Grid, may be declared under commercial operation irrespective of commissioning of other elements in a project. For projects under TBCB, the TSA shall prevail.

9.3.2.7 As regards the trial operation given in Regulation 6.3A.7 of the draft regulations, PGCIL has submitted that transmission elements are interconnection between upstream and downstream systems which are mostly owned by other utilities like Generators, State Transmission Utilities and Distribution Agencies. Any deficiency in the system of other utility may result in outage of elements of transmission licensees, e.g. the downstream system of ICTs normally belongs to the state utilities. ICTs are subjected to huge number of faults in the downstream system and due to deficiency in protection system in State Transmission utility network, ICTs may trip. Further, in number of cases there is interruption of power flow due to outage of upstream system including generating units and there are instances when transmission elements are required to be taken out manually due loss of voltage. The protection systems of utilities are not adequate resulting in delayed clearance of faults by the protection system provided in the elements of transmission licensee causing outage of transmission elements. Since the transmission elements are available for transmission of power for 100% of its rated capacity immediately after successful charging, establishment of its capacity is not relevant.Accordingly, “24 hours of service without any interruption due to reasons attributable to Transmission Licensee” may be specified while considering successful trial run and trial operation.For Projects under TBCB, the relevant provisions of TSA are to prevail.

9.3.2.8 As a practice, the date of commercial operation and the various provisions thereof are provided in the Terms and Conditions of Tariff Regulations and Transmission Service Agreement as applicable for Cost Plus and Tariff Based Competitive Bidding routes respectively. From above, it may be observed that the proposed supplementary draft amendment to the Indian Electricity Grid Code, Regulations, 2010 (Grid Code) are modifying the already existing provisions in various relevant Regulations/documents.In case the provisions of COD are required to be amended, the same may also be incorporated in the relevant Regulations/ documents.

9.3.2.9 National Load Despatch Centre (NLDC): As regards the date of commercial operation of the communication system (Clause 6.3.A.6 of the Supplementary Draft Regulations) requiring RLDCs to certify the transfer of voice and data to respective control centre, NLDC has submitted that it would not be possible for RLDCs to certify the part completion of work say single leg of OPGW communication. It is proposed that RLDCs shall verify it based on the affidavit furnished by the concerned utility. The Regulation may be reworded as follows:

> "Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a communication system or element thereof is put into service after completion of site acceptance test including transfer of voice and data to respective control centre as certified by the respective Regional Load Dispatch Centre **based on the affidavit furnished by the concerned entity**."

9.4 Analysis and Decision

9.4.1 We have considered the submissions of the stakeholders. To bring harmony and uniformity between the definition of COD in Tariff Regulation notified by the Commission and the Transmission Service Agreementunder the SBD for TBCB transmission projects, we proposed inclusion of definition of COD in the Grid Code. M/S Adani Power Ltd.has suggestedthat the standard RFP document released by Ministry of Power for selection of Transmission Service Provider through TBCB provides for the definition of COD as the date of charging of project or part thereof to its rated voltage levelor 7 days after the date on which it is declared ready for charging and further it does not refer to any role of CERC in such cases and therefore, such deviation from the competitive bidding guidelines would create ambiguity for COD of competitively bid projects. M/S Sterlite Power Grid Venture Ltd.and POWERGRID have also raised similar issue that regarding projects under TBCB, the definition of COD has been provided in the TSA and the provisions of the TSA are to prevail. In this connection, it is clarified that the Electricity Act, 2003 vests power in the Central Commission to regulate the inter-State transmission of electricity and to determine the tariff of inter-State transmission of electricity (Section 79(1)(c) and (d) of the Electricity Act, 2003) and to adopt the tariff where the tariff has been discovered through tariff based competitive bidding (Section 63 of the Electricity Act, 2003). Further, the Commission has been vested with the power to specify the Grid Code and the State Grid Codes have to be specified by the respective State Commission in conformity with the provisions of the Grid Code. Therefore, the Central Commission in exercise of the said statutory responsibility decided to specify the regulations with regard to trial run and commercial operation of the transmission system in the Grid Code which will be applicable to the projects implemented under cost plus as well as tariff based competitive bidding.Keeping in view the suggestions of the stakeholders, the provisions of Tariff Regulations as well as the TSA with regard to commercial operation and trial operation have been protected. In addition, the situations which are not covered under either the Tariff Regulations, 2014 or the TSA have been addressed.

9.4.2 M/S Adani Power Ltd.has submitted that Ministry of Power vide order dated 15.7.2015 has approved the policy for incentivising early commissioning of transmission projects which would entitle the transmission licensees to recover the transmission charges from the actual date of COD prior to the original scheduled COD. Adani Power has submitted that the said objective is being defeated through the proposed amendment. In this connection it is clarified that in the final regulations, it has been provided that in case of TBCB projects, the COD shall be declared as per the provisions of the TSA. As regards the incentivisation of the transmission projects executed under TBCB for their early commissioning as per the policy of Ministry of Power, Government of India, it is clarified that the amendments to the Grid Code does not deny the incentive as envisaged under the Government Policy but seeks to provide for a mechanism for smooth and dispute free implementation of the said policy. The Commission has examined the implication of the early commissioning in the context of the various provisions of the TSA in the order dated 28.1.2016 in Petition No. 284/ADP/2015 and has envisaged a mechanism for facilitating the implementation of the Government Policy. The decision of the Commission is extracted as under:

> "28. The petitioner has further submitted that the Ministry of Power, Government of India has issued Policy dated 15.7.2015 for incentivizing early commissioning of transmission elements before Scheduled Date of Commercial Operation (SCOD) by way of commencement of transmission charges from actual COD before SCOD. The petitioner has submitted that in the said Policy, it has been clarified that such incentive shall be applicable to transmission project(s)/elements(s) which are under implementation/ yet to be bid out under TBCB. The petitioner has submitted that it will take steps to avail the said incentives by commissioning the transmission elements before SCOD and has requested the Commission to take note of the said Policy andallow recovery of transmission charges from the actual COD in accordance with the Policy.
>
> 29. We have noted the submission of the petitioner. The Policy for incentivizing early commissioning of Transmission Projects issued by Ministry of Power vide its letter dated15.7.2015 is extracted as under:
>
> > "The undersigned is directed to say that the Hon`ble Minister of State (IC) for Power has approved the Policy for incentivizing early commissioning of Transmission projectsw.e.f.12.6.2015 as given below:
> >
> > > 1.1 For transmission system strengthening schemes under Tariff Based Competitive Bidding (TBCB) and also for such schemes awarded to PGCIL under compressed time schedule on cost plus basis, the developer shall get the following incentive for early commissioning of transmission project(s):
> > >
> > > > (i) Entitlement of the transmission charges from the actual date of Commercial Operation (COD) prior to the original scheduled COD.However, the number of years of applicability of tariff would remain unchanged i.e. for 25/35 years, as the case may be.
> > >
> > > Note: The above incentive will be applicable for the transmission project(s)/element(s) which are under implementation/yet to be bid out underTBCB/yet to be assigned to CTU (PGCIL) under compressed time schedule."

Thus, the Policy provides for grant of incentive in the form of admissibility of the transmission charges from the date of actual COD which takes place before the scheduled COD. In our view, the above Policy needs to be read in the context of the TSA.

Commercial Operation Date has been defined in the TSA as "the date as per Article 6.2; provided that the COD shall not be a date prior to the Scheduled COD mentioned in the TSA, unless mutually agreed to by all parties. Scheduled COD has been defined as under:

> ''Scheduled COD" in relation to an Element(s) shall mean the date(s) as mentioned in Schedule 3 as against such Element(s) and in relation to the Project, shall mean the date as mentioned in Schedule 3 as against such Project, subject to the provisions of Article 4.4 of this Agreement, or such date as may be mutually agreed among the Parties."

Scheduled COD has been given in Schedule 3 of the TSA with overall SCOD as 40 months from the effective date and certain elements have been pre-required for declaring the COD. At the end of the Schedule 3, the following has been mentioned:

> "The payment of Transmission Charges for any Element irrespective of its successful commissioning on or before its Scheduled COD shall only be considered after successful commissioning of the Element(s) which are pre-required for declaring the commercial operation of such Element as mentioned in the above table."

Article 6.2.1 of the TSA provides as under:

> "6.2.1 An Element of the Project shall be declared to have achieved COD seventy (72) hours following the connection of the Element with the Interconnection Facilities or seven (7) days after the date on which it is declared by the TSP to be ready for charging but is not able to be charged for reasons not attributable to the TSP or seven (7) days after the date of determent, if any, pursuant to Article 6.1.2:
> Provided that the Element shall be declared to have achieved COD only after all the Element(s), if any, which are pre-required to achieve COD as defined in Schedule 3 of this Agreement, have been declared to have achieved their respective COD."

From the above provisions, it emerges that certain elements can be considered for grant of transmission charges on completion of their successful commissioning on or before its Scheduled COD only after the successful commissioning of the pre-required elements. Therefore, the commissioning of the elements of the transmission system for the purpose of incentive should take into account the pre-required commissioning of the elements as per scheduled COD. Further there may be upstream or downstream assets which are executed by PGCIL on cost plus basis or by any other transmission licensee through competitive bidding. Since the SCOD of the transmission elements mentioned in Schedule 3 have been decided matching with the commissioning of the upstream or downstream assets, that is a requirement of matching commissioning of these upstream or downstream assets with the commissioning of the transmission system in case of early commissioning for the purpose of availing incentives as per the Policy direction of Ministry of Power. If the matching commissioning does not take place, then the transmission assets which have commissioned before the SCOD for the purpose of availing incentive will remain unutilized and in the absence of the assets being put into service, it will not be appropriate to load the DICs with the transmission charges. It is, therefore, directed that the petitioner should realistically forecast early commissioning of the element, liaise with the developer of the upstream and downstream assets and mutually decide the COD of the transmission assets matching with the COD of the upstream or downstream assets so that both can be benefited by the Policy of the Govt. for incentivizing the early commissioning of the transmission assets. In case of an element which can be put to use without the commissioning of the pre-required asset, the same can be commissioned, if the CEA certifies that the commissioning of the asset will be in the interest of the safety and security of the grid and the asset can be put to useful service after its commissioning.

Under the Policy of Government of India, Ministry of Power dated 15.7.2015, both the licensees executing ISTS under TBCB as well as PGCIL executing ISTS under compressed time schedule are entitled to tariff if they commission the assets prior to the Scheduled COD. Through the above order, the Commission has examined the scheme of incentives for early commissioning in the context of the various provisions of the TSA and has issued directions as to how the said scheme can be implemented within the framework of the TSA. In a meshed transmission network, no single transmission asset can be planned and executed in isolation. The transmission asset being executed has to serve its purpose i.e. to transmit electricity. It cannot serve its basic purpose unless it is connected at both ends to transmit electricity. While planning the transmission systems, CEA and CTU have decided the SCOD on the basis of the projected commissioning or availability of the upstream or downstream assets. The policy incentivises the transmission licensee to commission the transmission assets early in order to earn the transmission charges. In order to avail the incentives, if the transmission licensee decides to advance the commissioning unilaterally without consulting the Long Term

Transmission Customers, the planning agencies and the developers of upstream or downstream assets, it will lead to a situation where the asset after commissioning will remain stranded and will not serve the intended purpose and by virtue of the policy, the licensee will demand the transmission charges to be paid. To facilitate implementation of the policy of incentives by the Central Government, the Commission has directed that the licensee intending to advance the date of commissioning from SCOD shall realistically assess the date of early commissioning of its asset, liaise with the developer of the upstream and downstream assets and mutually advance the date of commissioning for the benefits of both. The Commission has further directed that licensee can declare commercial operation of the asset even if the pre-required asset is not ready, if CEA certifies that the asset can be put to useful service after commissioning.Accordingly, appropriate provisions have been made in the regulations.

9.4.3 Adani Power has submitted that there is contradiction betweenproviso (ii) and proviso (iii) of Clause 6.3A.5. We have considered the comments of APL. Proviso (ii) provides that where the asset is ready but is prevented from regular service on account of non-readiness of the upstream or downstream transmission systems executed by some other project developer, in that case the licensee shall approach the Commission for appropriate directions. Proviso (iii) deals with the commissioning of the pre-required assets by the same licensee. In fact, there is clear provision in the TSA that an asset will be commissioned only after the pre-required assets are commissioned. Both provisos operate in different situations and cannot be said to be contradictory. M/S Sterlite has submitted that proviso (iii) talks about commissioning of the pre-required assets before an asset is commissioned, but there have been situationswhere the pre-required asset cannot be completed for reason not attributable to the transmission licensee. Sterlite has suggested that in such cases,CTU should have the power to use the lines and put to regular service for other purposes as a part of integrated grid system and the transmission licensee should not be deprived of tariff. POWERGRID has also stated that in a complex grid, availability of each element increases reliability of the Grid. Further, the element of a project which is put under commercial operation as per their initial schedule and are supporting the Grid, may be declared under commercial operation irrespective of the commissioning of other elements in a project. In our view,TSA provides for commissioning of the transmission assets in a sequential manner as envisaged in the coordinated planning and the same should be adhered to. However, if it is found during actual commissioning that such sequence needs modification, and the same can be considered if approved by the Central Electricity Authority (CEA). This will enable execution of coordinated transmission system under changed scenario.We have accordingly added in proviso (v) of Regulation 6.3A.4 of Amended Regulations that "in case any element is required to be commissioned prior to the commissioning of pre-required element, the same can be done if CEA confirms that such commissioning is in the interest of the power system".

9.4.4POWERGRID has stated that the bidders cannot be burdened with the risk of entering into an Implementation Agreement with the Generator and more so, meet the requirement to match the generation schedule. The bidder under TBCB is governed to deliver the system as per the dates and provisions of the TSA. We find merit in submission of POWERGRID in regards to provisions of Scheduled COD of the TSA under TBCB, where the bidder has to deliver transmission system as per the dates and provisions of the TSA. In our view, this situation can be avoided if the evacuation line from the generating station to the nearest pooling station are executed by the generator or by CTU if the same has been included in the Coordinated transmission planning. This requires detailed deliberation and necessary changes in the Connectivity Regulations. We direct the staff to examine this aspect.

9.4.5The Commission has vide its order dated 05.08.2014 in petition No. 11/SM/2014opined that keeping in view the mismatch between commissioning of transmission system by an ISTS licensee and upstream/downstream system of STU, the ISTS transmission licensees and STUs should also sign such Implementation Agreement for development of ISTS and downstream system in coordinated way to avoid any mismatch. Accordingly, we have added proviso (ii) in Regulation 6.3A.4 of Amended Regulations stating that "Where the transmission system (transmission line or element thereof) of a transmission licensee is connected to the transmission system of any other transmission licensee, the transmission licensee shall endeavour to match the commissioning of its transmission system with the transmission system of the other licensee as far as practicable and shall ensure the same through an appropriate Implementation Agreement. Transmission licensee shall include the deemed transmission licensee".

9.4.6 As regards the commissioning of the transmission assets matching with the upstream and downstream assets, it may not be possible for the project developer implementing the transmission project under TBCB to enter into Implementation Agreement. However, matching the commissioning of the transmission assets should be periodically monitored by CEA. Where the transmission licensee implementing a project under TBCB intends to advance the commissioning of the project to an earlier date than the SCOD as envisaged in the TSA, it will be required to liaise with the LTTCs and the developer of the upstream or downstream project for matching commissioning of the assets. In this case also, CEA should coordinate among the developers to decide on a matching commissioning schedule and ensure adherence to such schedule.

9.4.7With respect to proposal of PGCIL that in future all the dedicated lines may be developed by respective generators, we are of the view that the same is beyond the scope of present amendment. However, the suggestion will be considered while dealing with the amendment to Connectivity Regulations.

9.4.8With respect to comments of POSOCO that it would not be possible for RLDCs to certify the part completion of work say single leg of OPGW communication and that RLDCs shall verify it based on the affidavit furnished by the concerned utility, we are of the view that RLDC needs to ensure flow of data in the part element to declare it commercial and just affidavit will not suffice.

9.4.9 In view of the above discussion, Regulation 6.3A.5 (renumbered as 6.3A.4) has been finalised as under:

"4. Date of commercial operation in relation to an inter-State Transmission System or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end:

Provided that:
(i) In case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee shall declare COD of the ISTS in accordance with the provisions of the Transmission Service Agreement.

(ii) Where the transmission line or substation is dedicated for evacuation of power from a particular generating station and the dedicated transmission line is being implemented other than through tariff based competitive bidding, the concerned generating company and transmission licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement in accordance with relevant provisions of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 or any subsequent amendment or re-enactment thereof. In case the transmission line or sub-station dedicated to a generator is being implemented through tariff based competitive bidding, then matching of commissioning of the transmission line/sub-station and generating station shall be monitored by Central Electricity Authority.

(iii) Where the transmission system executed by a transmission licensee is required to be connected to the transmission system executed by any other transmission licensee and both transmission systems are executed in a manner other than through tariff based competitive bidding, the transmission licensee shall endeavour to match the commissioning of its transmission system with the transmission system of the other licensee as far as practicable and shall ensure the same through an appropriate Implementation Agreement. Where either of the transmission systems or both are implemented through tariff based competitive bidding, the progress of implementation of the transmission systems in a matching time schedule shall be monitored by the Central Electricity Authority.

(iv) In case a transmission system or an element thereof is prevented from regular service on or before the Scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof.

(v) An element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as per the Transmission Services Agreement are commissioned. In case any element is required to be commissioned prior to the commissioning of pre-required element, the same can be done if CEA confirms that such commissioning is in the interest of the power system.

(vi) The transmission licensee shall submit a certificate from the CMD/CEO/MD of the Company that the transmission line, sub-station and communication system conform to the relevant Grid Standard and Grid Code, and are capable of operation to their full capacity.

Note: Transmission Licensee referred to in this Sub-Regulation shall include “Deemed Transmission Licensee” as per the provision of the Act.

5. Trial run and Trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at continuous flow of power, and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system in service enclosing certificate to that effect from concerned Regional Load Despatch Centre.

6. Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a communication system or element thereof shall be put into service after completion of site acceptance test including transfer of voice and data to respective control centre as certified by the respective Regional Load Dispatch Centre.”

10. Technical Minimum schedule for operation of generating stations

10.1 A new regulation regarding technical minimum schedule for operation of the generating station was proposed as under:

“**6.3B – Technical Minimum Schedule for operation of Generating Stations**

1. The technical minimum schedule for operation in respect of ISGS shall be55% of MCR loading of unit/units of generating stations.

2. A generating station may be directed by concerned RLDC to operate below85% but at or above the technical minimum schedule on account of grid security ordue to the less schedule given by the beneficiaries.

3. Where the generating station regulated by this Commission is directed by the concerned RLDC to operate at technical minimum schedule, the generation station may be compensated subject to the prudence check by the Commission in due consideration of average unit loading based on forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and aux energy consumption etc on an application filed by the generating company duly supported by relevant data verified by RLDC/SLDC.

Provided that in case of coal/lignite based stations, following station heat rate degradation shall be considered for the purpose of compensation:

S.No.	Unit loading as a % of Installed Capacity of the Unit	Increase in SHR (for supercritical units) (%)	Increase in SHR (for sub-critical units) (%)
1	85-100	Nil	Nil

2	75-84.99	1.25	2.25
3	65-74.99	2	4
4	55-64.99	3	6

Provided further where the scheduled generation falls below the technical minimum schedule, the generating station shall have the option to go for reserve shut down and in such cases start up fuel cost over and above 7 start/ stop in a year shall be considered as additional compensation:

Provided also that in case of gas based station compensation shall be decided based on the characteristic curve provided by the manufacturer and after prudence check of the actual operating parameters of Station Heat Rate, Auxiliary Energy Consumption, etc.:

Provided also that compensation so worked out by the Commission after prudence check shall be borne by the entity who has caused the plant to be operated at technical minimum. The name of the entity shall be mentioned in the order to be issued by the Commission.

4. In case of generating stations not regulated by the Commission, generating company shall have to factor above provisions in their PPAs for sale of power in order to claim compensations for operating at the technical minimum schedule.

5. The generating companies shall keep the record of the emission levels from the plant due to part load operation and submit a report for each year to the Commission by 31st May of the year.

6. NLDC in consultation with RLDCs/SLDCs, generating companies, beneficiaries and buyers of all regions at RPC forums, shall prescribe a Operating Procedure which shall be followed in certain specific grid conditions such as sudden load throw off or unit tripping significantly endangering grid security, identifying generating stations based on merit order despatch/stacking to be backed down in such contingencies for each region.”

10.2 Comments received:

10.2.1 Nabha Power Ltd. who is operating 2 X 700 MW supercritical plant at Rajpura in Punjab, has submitted that as the benefits and stability of supercritical units can be achieved by operating the unit at supercritical parameter, the Technical Minimum for such plant should be fixed accordingly.

10.2.2 GSECL has submitted that the base load machines are not designed for cyclic loading, the same shall not be operated at partial load and the units designed for flexible operation only shall be operated under cyclic conditions.Referring to report of Executive Director Level Committee of GSECL, it has been contended thatwhen moving from base load operating schedule to a flexible operating schedule there is an increased risk of undesirable effects/damages. The undesirable effects are increased equipment's damages, increased maintenance requirements and costs, unscheduled outages and additional safety concerns.

10.2.3 NTPC has submitted that the technical minimum schedule for operation in respect of ISGS should be at least 65% of MCR loading of unit/ units of coal generating stations. Similarly for gas stations, technical minimum schedule should be at least 65% of module (MCR) rating. NTPC has reiterated its submissions made in Petition No. 142/MP/2012 along with additional details of unit trips in NTPC from August 2013 to June 2015 while operating around 65-75% of MCR. It has also been submitted that at lower loading than 65% running of units with only TDBFP is not feasible and becomes highly unstable. It has further been submitted by NTPC that the generation of a unit operating at technical minimum could get further reduced automatically due to operation of auto controllers. Consequently some steps would be warranted to prevent such situations by suitable having some safety margins in the technical minimum to cater to such conditions. Similar margins may be necessary in certain units, particularly older/ lesser rated units which lack many of sophisticated control and automation, e.g. Badarpur TPS of NTPC. A similar situation could also arise during monsoon when wet coal received from mine end poses a challenge to proper combustion and flame stability in the furnace. Since safe and stable boiler operation is of paramount importance at all times, the operators may at times choose to operate at a slightly higher level to cater for the uncertainty. It is submitted that the operators be allowed this discretion in the interest of safe operation. This could include temporarily blocking the lower command of FGMO and other such controllers, wherever feasible. Also, for such operations at technical minimum, any penal provisions of the Regulations should not apply e.g. volume limits for deviation from schedule, additional deviation charge etc.

10.2.4 NLChas submitted thatthe boilers in both Stage-1 & Stge-2 of Thermal Power Station II were designed by M/s EVT, Germany and supplied by M/s Transelektro, Hungary & M/s. BHEL, India respectively. All the Boiler operating parameters will be in stable condition when load in the units are maintained at Maximum Continuous rating.

Lignite with 50% moisture and 175 VM in the fuel is fired in Neyveli Thermal Power station. This fuel is dried and pulverized using hot fuel gas drawn from the furnace and pulverized in the beater wheel mills. The firing is of tangential pattern from 6 PF burners and each mill delivers to one PF burner only.The fire ball established in the furnace is stable only when the load is greater than 80% or lignite flow is greater than 160t/hr when 5 mills in operation corresponding to 160 MW. The fire ball thus formed is balanced and centred in the furnace. When the load is less than 80% the fire ball gets distorted and shifted closer to the water-wall. It affects the water-wall in the form of overheating and slagging increases exponentially. This ultimately results in increase in furnace temperature greater than 950 degree C, at this enhanced higher temperature marcosite present in the lignite aggravates furnace fouling(Ash fusion temp, of FeS2 is around 750 degree C). The increase in furnace temperature affects mill performance, overheating of resuction ducts, refractory failures and deformation in PF ducts.

10.2.4.1 In case of TPS-I (Expansion), **i**f the Unit is operated at still lower loads, with 3 Mills Condition, tripping of any one mill on any reason will result in the tripping of all other Mills on "Loss of Fire Ball" protection leading to the tripping of Unit.Hence in TPS-I Expn. Minimum Load without Oil Support is fixed as 180 MW with 4 Mills Operation. Accordingly 160 MW is the Technical Minimum Schedule (Export) for Operation of each Unit at TPS-I Expansion, after deducting unit auxiliary power consumption of about 20 MW.For operation of Unit at 55% of MCR loading as notified by CERC in clause 6.3B of Draft Notification dated 02/07/2015, it may be required to operate the Boiler with 3 Mills Condition with Fuel Oil Support continuously for furnace/unit stability, due to the Fire Ball Protection available at TPS-I Expn.Considering above facts, the Technical Minimum Schedule (Export) for Operation of TPS-I Expn. may be fixed at 160 MW so that Unit can be operated at gross Load of about 175-180 MW for ensuring reliable operation of Units.

10.2.4.2NLC has further submitted that the TPS II Expansion is a new plant, with unit size of 250 MW and with CFBC Boilers. The Boiler is having 4 lignite feeders and 3 lignite feeders are normally required for full load operation, each supporting more than 80 MW. Any tripping of one feeders/stopping of one feeder will reduce the load to about 170 MW.

Only the recently, COD of the units was achieved and the units are still under stabilization. Difficulties are being experienced in stable operation of the unit, when one feeder trips for any reason, even when 4 feeders are in service. based on the operational experience gained so far, it is felt that the technical minimum load for stable operation without oil support is about 175 MW and accordingly the same (70% MCR-175 MW may please fixed as the technical minimum for the units of TPS II Expansion. NLS has further requested that they may permitted to approach the Commission for revision of this norm for TPS II Expansion if required based on further operation of this plant with CFBC boilers.

10.2.4.3Considering above facts, NLC has suggested the following for the lignite fired stations of NLC:

a) For TPS-II, Stage-I & Stage-II units, technical minimum is to be fixed above 60% and it may be fixed at 160 MW to ensure reliable operation of the units.

b) For TPS-I Expansion units, technical minimum is to be fixed above 80% and it may be fixed at 180 MW to ensure reliable operation of the units.

c) For TPS II Expansion Units, Technical minimum is to be fixed at 70% and it may be fixed at 175 MW.

10.2.5 APP, Tata Power and TNPCL has submitted that a pre specified level would not be appropriate measure for all the units of different sizes and operating under different conditions. As such the technical minimum may be specified corresponding to the unit size, variation in coal quality and OEM recommendation**.**

10.2.6 Adani Power has submitted that the Technical minimum may be taken as 55 % of MCR loading of unit and OEM recommendation whichever is higher.

10.2.7 MPPGCL has submitted that for old units of 40 MW and below having rendered 15 years of service, the technical minimum schedule should be 70% of MCR.

10.2.8 NEEPCO has submitted that the technical minimum for NEEPCO may be kept at 70% declared capacity considering minimum geographical condition of NER and constraint of gas supply.

10.2.9 POSOCO has submitted that the technical minimum level may be specified for gas based stations as well as hydro station.

10.3 Analysis and Decision

10.3.1 The Commission in the Explanatory Memorandum had given the following reasons for prescribing technical minimum schedule in respect of thermal generating stations:

> **"Issue of Technical Minimum for the thermal generating stations**
>
> 31. The issue of technical minimum has been under discussion for quite some time.
>
> 32. The State utilities/Discoms have raised the issue of technical minimum during the hearing before the Commission on Draft Deviation Settlement Mechanism (DSM) Regulations and in the hearing of Petition No 6/RP/2014. MPPMCL in Petition no 6/RP/2014 has submitted that in order to control drawal, SLDC submits request for zero/less quantum of Central Sector generation well in advance. However, RLDC allots quantity required for technical minimum capacity of Central Sector machines. The same applies with intra-state scheduling. Thus, intra-state entities have to accept this even though it is not required. MPPMCL has further submitted that there are international allocation from the ISGS of NTPC situated in Western Region, like allocation to Bangladesh and in order to ensure uninterrupted power supply to international allottees, the particular generating stations has to be remain operative even in extremely low demand situation. This results in to obligation of technical minimum on other beneficiaries of that particular station and may result in under drawal because of low system demand. Tripura State Electricity Co Ltd has made submissions in Petition No 6/RP/2014, that in case of sudden reduction in demand, the Utility immediately calls for revision of drawal schedule from various generating stations but such requests for revision of drawal schedule are not accepted by the RLDC/ISGS in totality on the plea of technical constraints (technical minimum). The Restoration of system normalcy by the distribution utilities take 5 to 12 hours depending upon severity of contingency and till such time continuous under drawal takes place and Regulation forces the utility without any compensation though the utility has no control over the above circumstances. Similar pleas have been made by the State utilities during the hearings of Draft DSM Regulations.
>
> 33. NTPC in Petition No 142/MP/ 2012 with regard to regulation of power by Power supply Grid has stressed the need of ensuring technical minimum schedule to NTPC

power stations. NTPC has requested POWERGRID and RLDCs to ensure technical minimum for its stations & that merit order of all inter-state generating stations may be considered while implementing Regulation drawing attention to clause 6.5.14 of CERC IEGC Regulations, 2010. NTPC in Petition No 142/MP/2012 has also submitted that scheduling at less than 70% load levels would affect the reliability of operation as well as the efficiency and economy of operation. In the long run, due to cyclic load fluctuation which in turn would also cause the operational parameters to vary, and would have an adverse impact on the machine health and life. Almost 30 years old stations like Singrauli and Korba are still running at high efficiency levels with minimum expenses and R&M mainly because of high loading factors of the units over the years. Although in the technical specification for the BTG supplier normally the power generators including NTPC put 30% of BMCR as the limit for stable operations, this limit is generally used for a performance guarantee test in a new boiler under controlled/ideal conditions with designed fuel and cannot be ensured over the life of the plant as normal operating conditions will vary from ideal/controlled operating environment.

34. To take a holistic view of the issue, the Commission in hearing dated28.5.2013 in Petition No 142/MP/2012 directed CEA to submit their views ontechnical minimum for thermal generating station. CEA in a communication dated12.9.2013 to CERC in Petition No. 142/MP/2012 has given following views on theissue of technical minimum:

> "The control range for coal fired unties is generally taken as 50% to 100% MCR and the rated steam temperature can be maintained in this range. However, the units can operate at any lower load without any limits; and minimum load without oil support is taken as about 30% MCR and operation below this limit needs oil support. The CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 prescribe a control load of 50% MCR. The operating capability generally specified in the technical specifications also stipulate continuous operation without oil support above 30% MCR load and control load range of 50% to 100% TMCR.
>
> Thus unit operation may be envisaged as indicated above, barring any specific operating constraints brought out or recommended by OEMs with proper technical justification."

10.3.2 In the above back drop, the concern of generating companies such as Notches merit but it needs to be appreciated that with the substantial capacity addition during the 11th Plan and capacity addition of around 88,537 MW planned during12th Plan as well as optimistic projection of incidence of renewable power capacity in the country in the near future, it is likely that there may be surplus situation during certain periods requiring generating units to shed load even below 65% to70 % of Installed Capacity/ MCR. Therefore, the technical minimum generation to be scheduled by a generating station needs to be reviewed.

10.3.3 It has been proposed that the technical minimum may initially be kept as 55% of installed Capacity/ MCRof unit/units for old as well as new plants in due consideration of CEA's recommendations and giving some margin over the recommended technical minimum of 50% by CEA. However, the operation at 55%loading has commercial implication for the generator in terms of increase in heat rate, secondary fuel oil consumption and auxiliary energy consumption, thereby increasing the actual energy charges. The generator will have to be compensated for this increase in energy charges.

10.3.4 It may be seen that most of generators has sought to increase the limit of technical minimum on various technical considerations specific to their stations. It has also been pointed out that technical minimum scheduling and taking unit in reserve shut down would lead to subjecting of units to cyclic loading and may adversely affect the health and life of units.

10.3.5 We appreciate the concern of the generators and the difficulties in unit operations due to technical minimum scheduling to the extent of 55% of MCR capacity but the question is whether it is avoidable under the changed conditions under which power system has to operate now and perceivable future. The answer is there is perceivable change in the conditions. Earlier under acute shortage situation units once available were getting full schedule and the supply of domestic coal was also not in short supply most of the time. As such, the most of stations in the country use to run as base load stations except in eastern region where due to lack of demand units were required to be back down and taken under reserve shut down. However, the position has changed drastically in recent years and power deficit has come down drastically to about 3.57% in 2014-15 due to large capacity additions during XI and XII plans. Then there is lot of capacity addition of renewable sources of energy and there is an ambitious plan to add about 175 GW of generation capacity based on renewable energy sources by 2022 (100 GW of Solar plus 60 GW of Wind and balance others). Further there is shortage of domestic coal requiring blending of imported coal. It has been seen that there have been increase in energy charges due to blending of imported coal and state Discoms are finding it difficult to afford to schedule power at such rates. The grid frequency is also remaining close to 50 Hz most of the time or above 50 Hz for substantial period. Under these circumstances higher scheduling than the technical minimum cannot be ensured all the time. Further, mere scheduling the units /station above the technical minimum by itself would not increase the demand on the system and would lead to operation of grid above 50 Hz thereby wasting the fuel unnecessarily and is not desirable. Therefore, relying on the CEA recommendations we are not inclined to change the limit of technical minimum schedule corresponding to 55% of the Installed capacity of unit. However, considering the concerns of generators in operating their unit at such low schedule corresponding to 55% of Installed capacity due to various technical constraints the generator will have the option to take its unit in reserve shut down at schedules below 55%. However, Commission is of the view that the generator should be adequately compensated for the loss of operational parameters due to operation of units at such technical minimumload below the normative operational level of 85%.

11. Compensation for Part load operation due to technical minimum schedule

11.1 The draft Regulation provide for compensation for partial loading in station heat rate, auxiliary energy consumption and specific fuel oil consumption depending upon unit loading due to technical minimum schedule.

11.2 Comments received:

11.2.1 NTPC, APP and Tata Power have submitted that Station Heat Rate compensation specified is not sufficient. NTPC has given a different value for Super-critical and Sub-critical units. APP and Tata power has further submitted that there should be additional compensation for variation of GCV of coal and Compensation should also be available for Ultra Mega Power Project and projects under Case-I bidding**.**

11.2.2 NTPC has submitted that HR Variation in NTPC design vis-à-vis CERC proposed provision is as given below. Accordingly, in the loading factor range of 65 of 85%, provision should be made for compensation as given below:

Sl. No	Unit Loading	Increase in SHR (Super-critical units		Increase in SHR (Sub-critical units)	
	% of MCR	Proposed by CERC	Variation in Design value as per NTPC	Proposed by CERC	Variation in Design value as per NTPC
1.	85 – 100	NIL	0.8	Nil	0.8
2.	75 – 84.99	1.25	1.8	2.25	2.3
3.	65 – 74.99	2.0	3.1	4.0	4.0

11.2.2.1 NTPC has further submitted that the Heat Rate Variation for 65% - 55% range on extrapolation of Heat Balances Diagram (HBD) is 4.6 and 6.2% for super – critical and sub-critical units respectively.

11.2.2.2 NTPC has also submitted that the CERC has proposed that compensation for HR & APC in case of gas stations will be based on Characteristic curves provided by the manufacturer. Gas stations are practically given very low schedule, but the design Heat balance Diagram (HBD) is available only up to 60% and in some cases it is up to 80% only. Extrapolation of curve developed based on Heat Balance Diagram (HBD) loading does not reflect the correct HR at very low loading factor. In such case actual change in HR at lower loading (below the available design HBD provided by OEM) may be considered and compensated over the tariff HR.

Sl. No.	Station	Design HR Impact per % Change in LF	
		80-100	60-79.99
1	3GT+ 1ST	1.0	7.2
2	2GT+ 1ST	2.61	9.27

11.2.3 GSECL has submitted that as per the observation of deterioration of heat rate at part load operation, the heat rate is increased by about 100-150 kcal/kwh and auxiliary power consumption increases by about 0.7 to 1%. As recommended by BHEL and our observation of last 3 to 4 years, the deterioration in Heat rate at part load operation is under:

Sl. No.	Unit loading as a % of installed capacity	Increase in SHR % (Sub critical units)
1	85-100	2.00
2	75-84.99	4.20
3	65-74.99	6.10
4	55-64.99	8.15

11.2.4 POSOCO has submitted that a separate provision may be made for compensation against SuoMotu downward revision in schedule by RLDC for transmission constraint/grid security/ better system operation.

11.2.5 NLC has submitted thatallowing compensation for degradation of Heat rate due to operation in Technical Minimum is also a welcoming feature. But simplified procedure to be in place for claiming compensation for degradation of Heat Rate due to operation in technical Minimum conditions.

11.2.6 GRIDCO has submitted thatthe CERC may take into consideration the following factors while deciding the compensation for technical minimum schedule for the generating stations:

(a) The reason of not availing the allocated quantum as per agreement by the beneficiaries from the respective generating station;

(b) Whether the rate of energy for the said power station is at par with prevailing market rate;

(c)The reason of inability of the generating companyto sell the un-requisitioned power in market;

(d) Is the unit producing electricity as per the fuel source mentioned in initial offer of the generating company & that as accepted by the beneficiary;

(e) Is the rate of electricity of the concerned generating station is in the interest of consumers in terms of affordability;
(f) Is such Technical Minimum balancing the interest of both generators and consumers;

(g) What is the designated/ designed source of fuel for the generating station as per DPR;

(h) Whether the generator is utilizing the fuel from designated sources as per the DPR;

(i) The reason of non-utilization of fuel from the designated source;

(j) Is the alternative fuel instead of from designated source is used in fuel shortage scenario/ optimization of generation;

(k) Is it feasible and in the interest of consumers to bear the extra cost of electricity due to use of high cost fuel from alternative source other than the designated source of fuel.

10.2.7 POSOCO has submitted that verification of secondary fuel oil consumption and auxiliary energy consumption is not possible for RLDC/SLDC. Further, in case of unit tripping generation may have to be increased.

11.3 Analysis and Decision

11.3.1 GRIDCO has submitted that the generator should not be compensated for reduction in demand due to use of fuel other than designated fuel. However, it needs to be appreciated that it would be very difficult to distinguish between reductions in requisition by the beneficiaries is on account of use of fuel other than designated fuel or it is due to reduction in demand of beneficiary itself. Further, in the existing dispensation fuel supply risk is that of Generator but the fuel price risk and the fuel quality risks are passed on to the beneficiaries. Generator is free to arrange fuel from alternate sources including imported coal. Therefore, once the generator has arranged coal and has declared its availability any consequential increase in cost due to less requisition by the beneficiaries, or reduction in schedule due to grid condition or due to injection of RE power etcwhich is beyond their control needs to be made good to them. Further, at the existing level of technical minimum of 65-70%, the beneficiary is required to bear the energy charges up to such minimum schedule. However, there would now be savings in the energy charges despite paying marginal compensation to the generator.

11.3.2 The variation of SHR as proposed by CERC and as indicated by NTPC and GSECL for coal based generating stations is as follows:

Sl. No	**Unit Loading**	**Increase in SHR (Super-critical units**		**Increase in SHR (Sub-critical units)**		
	% of MCR	**Proposed by CERC**	**Variation in Design value as per NTPC**	**Proposed by CERC**	**Variation in Design value as per NTPC**	**Variation as per GSECL**
1.	85 – 100	NIL	0.8	Nil	0.8	2.0
2.	75 – 84.99	1.25	1.8	2.25	2.3	4.2
3.	65 – 74.99	2.0	3.1	4.0	4.0	6.10
4.	55 - 64.99	4.0	4.6	6.0	6.2	8.15

11.3.3 It needs to be appreciated that the station heat rate norms specified by the Commission is in due consideration of average unit loading of units during period 2008-09 to 2012-13 of the order of 91% and normative operation of units of 83-85% during the year and thus the variation in heat rate up to 85-100% is already included in the norms specified. On this consideration the heat rate degradation proposed by the Commission from the specified heat rate norms appears to be reasonable.

11.3.4 As regard heat rate degradation in case of gas based stations is concerned it shall be considered on case to case basis in due consideration of unit loadings, heat rate norms allowed and depending upon operation of units on open cycle and combined cycle mode. It needs to be appreciated that the Commission has specified heat rate norms for the open cycle as well as combined cycle operation.

11.3.5 NTPC has submitted that the methodology for calculating compensation for Auxiliary Power consumption should also be provided. GSECL has submitted that the auxiliary power consumption increases by about 0.7 to 1% as a result of partial loading of units. NTPC has submitted that while compensation is proposed for APC, methodology to calculate the same has not been provided for coal stations. The APC variation w.r.t loading factor in the range of 100-65% based on NTPC's experiences, is as given below:

Sl. No	Unit Loading (% of MCR)	Currents APC (With CT) Norms (%) for 500 MW units	% Average variation in APC	Expected APC (%) at various load range.
1.	100-85	5.75	8.15	6.2
2.	85-75	5.75	21.5	7.0
3.	75-65	5.75	28.5	7.4

% average variation in APC Data in 65-55% range is 35.5% and expected APC of 7.8% Data for 65-55% range is given based on extrapolation of actual APC.

11.3.6 The degradation as per some of their stations such as Sipat, Kahalgaon and Dadrietc has shown followingdegradation in different years at low loading of units as is evident from CEA report on operational norms as given below:

Sl. No.	Name of Station	Year	Average Unit loading (%)	% AEC	CERC Norms
1	Kahalgaon	2008-09	48.9	7.6	6.74
2	Sipat	2008-09	50.5	5.0	5.75
3	Sipat	2011-12	45.5	5.8	5.75
4	Dadri	2009-10	51.7	7.9	6.75

It may be seen that the variation in AEC in case of steam driven BFP is not much. However, in case of electrical driven BFP the variation is upto 1.15% from the norms. This could be because of the fact that unit loading is around 50% due to shutting down of half of unit and station auxiliaries and would not be of any assistance to us.

11.3.7 However, considering the suggestion of GSECL and NTPC and that the norms of aux energy consumption corresponds to normative operation level of 83-85%, following percentage degradation is allowed for the sub-critical and super-critical units up to loading of 55-64.99% in a graded manner as follows:

Sl. No	**Unit Loading (% of MCR)**	**% Variation in AEC admissible**
1.	85 – 100	NIL
2.	75 – 84.99	0.35
3.	65 – 74.99	0.65
4.	55 - 64.99	1.00

11.3.8 MPPGCL has submitted that the units going for shut down, compensation shall be admissible for each start/stop on a year. GSECL has also submitted thatthe consumption for start-up costs for each start/stop due to reserve shut down may be allowed instead of benchmark of 7 nos. per year and the actual cost of oil consumption should be reimbursed by the beneficiaries.

11.3.9 CEA in its recommendations to the Commission on operational norms for the period 2014-19 had recommended a norm of 0.25 ml which included around 7 start/stop of units along with additional compensation for each start up based on the following:

Unit Size (MW)	Oil Consumption per start up (Kl)		
	Hot	Warm	Cold
200/210/250 MW	20	30	50
500 MW	30	50	90
660 MW	40	60	110

However, the norms specified by the Commission is 0.5 ml/kWh for all generating stations. Therefore, any compensation for more specific oil consumption could be allowed in excess of above norms of 0.5 ml/kWh and considering oil consumption depending upon type of startup and no. of startups. This would be in addition to the other compensation on account of SHR reduction and AEC increase.

11.3.10 NTPC has further submitted that the compensation shall not be included in the scope of truing up of operating norms provided under Regulation 8.6 (6) of the Tariff Regulations as it would be against the very concept of providing this compensation. We are however, unable to agree with NTPC that any compensation payable to the generators in due consideration of its actual and operational norms allowed to them and reconciled at the end of the year.

11.3.11 It needs to be appreciated that fuel supply risk rest with the generators and in case generator is unable to declare the availability or declare the availability below the normative availability due to fuel shortage in that case they would not be entitle to any compensation for the quantum not declared.

11.3.12 Further, CERC has recently notified Central Electricity Regulatory Commission (Ancillary Service Operations) Regulation 2015 on 19.08.2015. The power for Regulation up and down services under these regulations shall be paid for in terms of this Regulation. Hence any change in schedule of power under this regulation shall not be considered for compensation under these Regulations to avoid double compensation.

11.3.13 NTPC and SRPC have also submitted that the provision of reserve Shut Down is not in consonance with provision of technical minimum schedule. However, considering the technical constraint as expressed by the generators it may be necessary to provide such an option to the Generators. NTPC has submitted that call for reserve shut down may be taken by the respective RLDCs but we feel that the call for going for reserve shut down has to be taken by the generators only. They are however, free to consult RLDC if deemed fit.

12. Computation of compensation

12.1 The Commission had proposed to compensate the generating stations subject to the prudence check by the Commission in due consideration of average unit loading based on forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and aux energy consumption etc on an application filed by the generating company duly supported by relevant data verified by RLDC/SLDC.

12.2 **Comments Received**:

12.2.1 NTPC has submitted that impact of partial loading is event wise and assessment of its impact and compensation thereof on annual average basis is over simplistic and does not reflect the actual costs as the same are not linearly proportional to the loading levels while the average operating level is the linear (arithmetic) average of loading levels over different periods. Moreover, it is suggested that it cannot be the case that there is a need for compensation when schedules are at technical minimum level and no such requirement when the schedules are slightly higher than the technical minimum.

12.3 Analysis and Decision

12.3.1 The Commission is of the view that NLDC should finalize a detailed operating procedure and methodology to be followed in certain specific grid conditions of low system demand, Regulation of power supply, incidence of high renewableetc in identifyinggenerating stations in their respective region based on merit order stacking to be backed downup to the Technical minimum, data requirements, role of different agencies, procedure for unit going in to reserve shut down in consultation with the generators and beneficiaries at RPC forums within 2 months' time in terms of above and submit to the Commission for its approval. The RPCs shall also workout a mechanism for compensation for station heat rate and aux energy consumption for low unit loading on monthly basis in terms of energy charges and compensation for secondary fuel oil consumption over and above the norm of 0.5 ml/kWh for additional start-ups in excess of 7 start-ups,in consultation with generators and beneficiaries at RPC forum and its sharing by the beneficiaries. This would avoid the necessity of filing separate petitions before the Commission.

12.3.2 Thecompensation worked out based on mechanism of RPCshall be borne by the entity who has caused the plant to be operated at a schedule lower than the corresponding to normative availability and up to technical minimum schedule. In case of generatingstations not regulated by the Commission, the generating company shall have to factor these provisions in the PPA for sale of power in order to claim compensation for operating at the technical minimum schedule. In case of Regulation of Power supply the compensation shall have to be factored in the sale to the third party.

12.3.3 POSOCO has also submitted that the role of ISGS, beneficiaries and RLDC may be specified when cumulative requisition of beneficiaries is below the technical minimum of 55%.FurtherMinimum duration of Reserve shut down may also be specified. As discussed earlier, call for reserve shut down has to be taken by the generator and once generator decides for reserve shut down, then the RLDC /SLDCs will have to schedule the station accordingly.

12.3.4Accordingly, provisions relating to technical minimum are suitably incorporated in the IEGC.

"6.3B – Technical Minimum Schedule for operation of Central Generating Stations and Inter-State Generating Stations

1. The technical minimum for operation in respect of a unit or units of a Central Generating Station of inter-State Generating Station shall be 55% of MCR loading or installed capacity of the unit of at generating station.

2. The CGS or ISGS may be directed by concerned RLDC to operate its unit(s) at or above the technical minimum but below the normative plant availability factor on account of grid security or due to the fewer schedules given by the beneficiaries.

3. Where the CGS or ISGS, whose tariff is either determined or adopted by the Commission, is directed by the concerned RLDC to operate below normative plant availability factor but at or above technical minimum, the CGS or ISGS may be compensated depending on the average unit loading duly taking into account the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis duly supported by relevant data verified by RLDC or SLDC, as the case may be:

Provided that:

(i) In case of coal / lignite based generating stations, following station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation:

Unit loading as a % of Installed Capacity of the Unit	Increase in SHR (for supercritical units) (%)	Increase in SHR (for sub-critical units) (%)
85-100	Nil	Nil
75-84.99	1.25	2.25
65-74.99	2	4
55-64.99	3	6

(ii) In case of coal / lignite based generating stations, the following Auxiliary Energy Consumption degradation or actual, whichever is lower, shall be considered for the purpose of compensation:

Sl. No	Unit Loading (% of MCR)	% Degradation in AEC admissible
1.	85 – 100	NIL
2.	75 – 84.99	0.35
3.	65 – 74.99	0.65
4.	55 - 64.99	1.00

(iii) Where the scheduled generation falls below the technical minimum schedule, the concerned CGS or ISGS shall have the option to go for reserve shut down and in such cases, start-up fuel cost over and above seven (7) start / stop in a year shall be considered as additional compensation based on following norms or actual, whichever is lower:

Unit Size (MW)	Oil Consumption per start up (Kl)		
	Hot	Warm	Cold
200/210/250 MW	20	30	50
500 MW	30	50	90
660 MW	40	60	110

(iv) In case of gas based Central Generating Station or inter-State Generating Station, compensation shall be decided based on the characteristic curve provided by the manufacturer and after prudence check of the actual operating parameters of Station Heat Rate, Auxiliary Energy Consumption, etc.

(v) Compensation for the Station Heat Rate and Auxiliary Energy Consumption shall be worked out in terms of energy charges.

(vi) The compensation so computed shall be borne by the entity who has caused the plant to be operated at schedule lower than corresponding to Normative Plant Availability Factor up to technical minimum based on the compensation mechanism finalized by the RPCs.

(vii) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and / or actual Auxiliary Energy Consumption are lower than the normative Station Heat Rate and / or normative Auxiliary Energy Consumption applicable to the unit or the generating station.

(viii) There shall be reconciliation of the compensation at the end of the financial year in due consideration of actual weighted average operational parameters of station heat rate, auxiliary energy consumption and secondary oil consumption.

(ix) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and / or actual Auxiliary Energy Consumption are lower than the normative station Heat Rate and / or normative Auxiliary Energy Consumption applicable to the unit or the generating station in a month or after annual reconciliation at the end of the year.

(x) The change in schedule of power under the provisions of Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 shall not be considered for compensation.

4. In case of a generating station whose tariff is neither determined nor adopted by the Commission, the concerned generating company shall have to factor the above provisions in the PPAs entered into by it for sale of power in order to claim compensations for operating at the technical minimum schedule.

5. The generating company shall keep the record of the emission levels from the plant due to part load operation and submit a report for each year to the Commission by 31st May of the year.

6. NLDC shall prepare a Detailed Operating Procedure in consultation with the generators and beneficiaries at RPC forums within 2 months' time and submit to the Commission for approval. The Detailed Operating Procedure shall contain the role of different agencies, data requirements, procedure for taking the units under reserve shut down and the methodology for identifying the generating stations or units thereof to be backed down upto the technical minimum in specific Grid conditions such as low system demand, Regulation of Power Supply and incidence of high renewables etc., based on merit order stacking.

7. The RPCs shall workout a mechanism for compensation for station heat rate and auxiliary energy consumption for low unit loading on monthly basis in terms of energy charges and compensation for secondary fuel oil consumption over and above the norm of 0.5 ml/kWh for additional start-ups in excess of 7 start-ups, in consultation with generators and beneficiaries at RPC forum and its sharing by the beneficiaries."

12.3.5 Since Sub-Regulation 6.3B can only be operationalized after approval of the Detailed Procedure to be prepared by NLDC, the amendment to the Grid Code except Sub-Regulation 6.3B shall come into effect from the date of notification and Sub-Regulation 6.3B shall come into effect from a date to be notified by the Commission.

12.3.6 The Commission directs the staff to take necessary action to notify the approved fourth amendment to the Grid Code in the Official Gazette.

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(Dr. M.K. Iyer) (A. S. Bakshi) (A.K. Singhal) (Gireesh B. Pradhan) Member Member Member Chairperson