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Ref: RA/BYPL/2018-19/213 Date:28 January 2019

To,

Secretary,

Central Electricity Regulatory Commission

3rd & 4th Floor, Chanderlok Building, 36, Janpath

New Delhi - 110001

Subject: Comments on Draft CERC (Terms and Conditions of Tariff Regulation) 2019 for the Tariff period 01.04.2019 to 31.03.2024

Dear Sir,

We write in reference to the Draft CERC (Terms and Conditions of Tariff Regulation) 2019 for the Tariff period 01.04.2019 to 31.03.2024

Please find enclosed the comments of BYPL as Annexure-1 for kind consideration of the Hon'ble CERC.

Thanking you,

Your's sincerely,

Gagan Swain

Head-Regulatory Affairs

Encl: As above

Draft Regulations	Comments/Rationale	Proposed Regulations
1. Short title and commencement. - (1) These regulations may be called the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019. (2) These regulations shall come into force on 1.4.2019, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of five years from 1.4.2019 to 31.3.2024: Provided that where a generating station or unit thereof and transmission system or an element thereof, has been declared under commercial operation before the date of commencement of these regulations and whose tariff has not been finally determined by the Commission till that date, tariff in respect of such generating station or unit thereof and transmission system or an element thereof for the period ending 31.3.2019 shall be determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 as amended from time to time.	• **Draft Regulation 1(2):** provides that Tariff Regulations shall remain in force for a period of five years with effect from 01.04.2019 and shall continue till 31.03.2024. Section 61 of the Electricity Act, 2003 enshrines the principle that generation and transmission are conducted on commercial principles as well as on efficiency, good performance so that the fundamental corner stone of the Electricity Act of safeguarding of consumer's interest, is secured. • It is requested to mandate the implementation of improved operational norms as specified under the new Regulations from date of enforcement i.e. 01.04.2019 itself which shall be subject to True-up under these Regulations, since:- a) It is noticed/ apprehended that the applicability of the improved normative operational norms are deferred/sought for deferral by GENCO/ Transco from date of notification of the CERC Tariff Regulations. b) There have been various instances of in-ordinate delay in implementation of improved operational norms. For instance, NTPC had delayed the implementation of the Operational Norms in in FY 2014-19 for over one and a half years. Due to the same delay Amounts of about Rs. Rs. 85 Crs and Rs. 49 crs were respectively credited to BRPL and BYPL on account of implementation of revised operational norms c) Due to the same the distribution licensee and ultimately	Add the following as the first proviso : *"Provided that these regulations shall be implemented from 01.04.2019 which shall be subject to true-up under these regulations. Any loss caused due to delay in implementation of these regulations shall be refunded to the beneficiaries along with applicable carrying cost.*

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td></td><td>the consumers have suffered huge losses of about Rs. 11 crs and Rs. 6 crs for BRPL and BYPL respectively on account of carrying cost.
• Therefore, this Hon'ble Commission may specify a provision to recoup any loss caused due to delay in implementing these Regulations from the enforcement date. The loss must be refunded to the distribution licensee with carrying costs.</td><td></td></tr>
<tr><td>2. Scope and extent of application.- (1) These regulations shall apply in all cases where tariff for a generating station or a unit thereof and a transmission system or an element thereof is required to be determined by the Commission under section 62 of the Act read with section 79 thereof:
Provided that any generating station for which agreement(s) have been executed for supply of electricity to the beneficiaries on or before 5.1.2011 and the financial closure for the said generating station has not been achieved by 31.3.2019, such projects shall not be eligible for determination of tariff unless fresh consent of the beneficiaries is obtained and furnished.
(2) These regulations shall not apply to the following cases:-</td><td>• Proviso to Draft Regulation 2(1): Provides, fresh consent of the beneficiaries to be obtained, for determination of tariff, by generating station for which agreement(s) for supply of electricity have been executed on or before 05.01.2011 and financial closure has not been achieved by 31.3.2019.
• We propose that in addition to the aforesaid factors viz., issue of inordinate delay in achieving COD should also be added for requirement of fresh consent of beneficiaries, since:
a) Section 61(b) of the Electricity Act provides that the terms and conditions of tariff to be based on commercial principles.
b) Commercial principles, inter-alia emphasizes the risk allocation through contractual arrangement such as power purchase agreement in case of generation, and transmission service agreement or long-term access</td><td>Modify the first proviso to read as follows:-
Provided that (a) any generating station for which agreement(s) have been executed for supply of electricity to the beneficiaries on or before 5.1.2011 and the
financial closure for the said generating station has not been achieved by 31.3.2019, <u>or (b) where the COD has been delayed beyond two years from the Scheduled COD ,</u> such projects shall not be eligible for determination of tariff unless fresh consent of the beneficiaries is obtained and furnished.</td></tr>
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<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>(a) Generating stations or inter-State transmission systems whose tariff has been discovered through tariff based competitive bidding in accordance with the guidelines issued by the Central Government and adopted by the Commission under section 63 of the Act;
(b) Generating stations based on renewable sources of energy whose tariff is determined in accordance with the Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2017, as amended from time to time or any subsequent enactment thereof.</td><td>agreement in case of transmission service.
c) There have been various instances of inordinate delay in COD of various Central Sector Generating Plant (Viz. THDC, NTPC etc.) such as follows :
<table><tr><th>S No</th><th>Project</th></tr><tr><td colspan="2">NTPC</td></tr><tr><td>1</td><td>Anta Gas-II</td></tr><tr><td>2</td><td>Auriya Gas-II</td></tr><tr><td>3</td><td>North Karanpura</td></tr><tr><td>4</td><td>Lata Tapovan</td></tr><tr><td>5</td><td>Singrauli Stage-III</td></tr><tr><td>6</td><td>Tanda TPS-II</td></tr><tr><td>7</td><td>Tapovan Vishnugad</td></tr><tr><td>8</td><td>Gidderbaha</td></tr><tr><td>9</td><td>Bilhaur</td></tr><tr><td colspan="2">Tehri PSP</td></tr><tr><td>1</td><td>Tehri PSP</td></tr></table>
d) These plants have beenallocated by the executive instructions of the Central Government and subsequently PPA has been signed which are yet to be in many cases still approved by the StateCommission. However, at the time whenthe PPA was signed the distribution licensee had estimated the capital cost of the generating stations based on the timelines reckoned</td><td></td></tr>
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Draft Regulations	Comments/Rationale	Proposed Regulations
	from the investment date approval of the generating company (as per the rule prescribed in appendix I of the CERC Tariff Regulations). For example, if the PPA was signed in the year 2010 and the investment approval was granted in the year 2010 the distribution licensee estimated that the CoD of the generating station would be achieved within 33 months (Green Field Projects) or 31 months (for Extension Projects) / 44 months, 42 months/ 52 months, 50 months, depending upon the size of the project and also depending upon the technology. Therefore, if the investment approval is dated 2010 then the CoD should have been in 2013 in that case the capital cost would have been Rs. X/MW. However, if the CoD is delayed and is in 2017 then the capital cost would be Rs.X*2/ MW. Such delay adversely affects the DISCOMs as they will be faced with higher capital cost which they have never envisaged or agreed to while signing the PPA. This is solely for the fault on the part of the generating company. Therefore, consent of the DISCOMs must be mandated where the COD has been delayed beyond two years from the Scheduled COD.	
3. Definitions. - In these regulations, unless the context otherwise requires:-		

Draft Regulations	Comments/Rationale	Proposed Regulations
(7) **'Bank Rate'** means the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points;	**<u>Draft Regulation 3(7)</u>** provides that the Bank Rate is the rate of interest levied on the refund and recovery after truing up by the Hon'ble Commission. • GENCO/TRANSCO and the beneficiaries recover the interest cost to the extent borrowed for the funding of the project cost, working capital etc. • Therefore, the interest determined is being paid to the **GENCO**/TRANSCO for recovery of their borrowing cost and is not meant to allow the GENCO/TRANSCO to profit from the same. • Hon'ble Commission, in the Draft Regulations, has defined the term 'Bank Rate' as '*the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points*'. In fact:- a) 350 basis point is not reflective of the current governing financial scenario as published by the Central Bank. b) It is approximately 200 basis point. Moreover, it may be noticed that the actual rate of interest admissible to the GENCO/TRANSCO may be much lower than the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points. c) Hence, the consumer would always be at loss by paying inaccurate rate of interest.	(7) **'Bank Rate'** means the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus margin. Explanation - Margin shall be difference between MCLR and actual interest cost of the generating company or transmission licensee for the last control period;

Draft Regulations	Comments/Rationale	Proposed Regulations
	• In view of the above concerns, the bank rate should be lower of the one year MCLR of the State Bank of India issued from time to time plus 350 basis points or **the** actual rate of interest. • Apart from the above, Hon'ble Commission while framing **Tariff Regulations 2014 had, in its statement of reasons**, provided following reasoning for considering Bank rate as the Base Rate of interest specified by the State Bank of India (SBI) from time to time or any replacement thereof for the time being in effect, plus 350 basis points *"The SBI PLR has ranged between 300-400 basis points over the Base Rate, which varies on account of several factors and financial scenarios. On the other hand, Bank Rate is applicable on under recovery or over recovery on account of true up, which can either be applicable to generating company/ transmission licensee or beneficiaries/long-term customers as the case may be.* ***The Commission has observed that Bank Rate specified is not discriminatory either to a generating Company or beneficiaries and is in line with <u>current financial scenario.</u>*** *Hence, the definition of Bank Rate as specified in the Regulations is appropriate and the Commission has, therefore, decided not to modify this provision of the draft Regulations."* • As evident from above, Hon'ble Commission had framed the aforesaid regulation considering the financial scenario prevailing at that point in time i.e., FY 2013-2014.	

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<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
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<td>However, the same has changed which is evident from Average Lending rate of scheduled commercial banks versus Marginal cost of lending rate:
<table>
<tr><th>Month</th><th>Avg. Lending Rate of Scheduled Commercial Banks (%)</th><th>Marginal Cost of Lending Rates (MCLR) (%)</th><th>Diff. (%)</th></tr>
<tr><td>Apr-16</td><td>11.20%</td><td>9.20%</td><td>2.00%</td></tr>
<tr><td>Apr-17</td><td>10.83%</td><td>8.00%</td><td>2.83%</td></tr>
<tr><td>Apr-18</td><td>10.29%</td><td>8.15%</td><td>2.14%</td></tr>
</table>
SOURCE: RBI and SBI website
In terms of the aforesaid table the current financial scenario suggests that there is difference is approx. 200 basis point. Noteworthy is the fact that the borrowing cost for GENCO/Transmission Company is much lesser. The Hon'ble Commission should therefore consider the Bank Rate ought to be considered at actuals.
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<td>(8) 'Beneficiary' in relation to a generating station covered under clauses (a) or (b) of sub-section 1 of section 79 of the Act, means a distribution licensee who is purchasing electricity generated at such generating station by entering into a Power Purchase Agreement either directly or</td>
<td><u>Draft Regulation 3(8):</u>The second proviso is legally untenable for the following reasons : -
a) Central Government allocations are in the nature of instructions. Appellate Tribunal held in Appeal No. 106 and 107 of 2009 that Government / executive</td>
<td>The second proviso of Regulation 3(8) requires to be omitted/ deleted.</td>
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</table>

Draft Regulations	Comments/Rationale	Proposed Regulations
through a trading licensee on payment of fixed charges and variable charges by scheduling in accordance with the Grid Code: Provided that where the distribution licensee is procuring power through a trading licensee, the arrangement should be secured through back to back power purchase agreement and power sale agreement: Provided further that beneficiary shall also include any person who has been allocated capacity in any generating station owned and controlled by the Central Government;	instruction or notification/ policy documents/ subordiate legislations cannot restrict or whittled down the exercise of power under Section 86(1) (b) of 2003 Act. There is no section / provision in the 2003 Act empowering Central Government to allocate electricity from generating stations to any beneficiary. Even the statement of Minister of State for Power Shri Piyush Goyal is that allocation from central generating stations to beneficiary state is in accordance with the formula which is treated as "guidelines" [Ref.GoI, M/o Power, Lok Sabha, St. Question No. 41 answered on 26.02.2015 (Allocation of Power to States)]. It is settle law that guidelines are not to be treated as statute nor is an unapproved PPA to be treated as statute. In view of the above, the second proviso of Regulation 3(8) requires to be omitted/ deleted.	3(26): (a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, ~~or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years~~; or

Draft Regulations	Comments/Rationale	Proposed Regulations
(16) **'Declared Capacity'** or **'DC'** shall have the same meaning as defined in Grid Code; (26) **'Force Majeure'** for the purpose of these regulations means the event or circumstance or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission licensee to complete the project within the time specified in the Investment Approval, and only if such events or circumstances are not within the control the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices:	• **<u>Draft Regulation 3(26)(a):</u>** The said provision recognises exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years as force majeure. The same needs to be reconsidered as:- a) various instances of adverse weather conditions are already included in the proposed regulation underAct of God. There is no need to include the adverse weather conditions as a separate provision. b) The clause is very widely worded and the same may lead to frivolous claims. For instance invarious cases before this Hon'ble Commission and Appeals pending before Appellate Tribunal, the claimsrejecting claimed by NTPCfor relief under force majeure are raised by statingadverse weather condition100 years. The same have been rejected by this Hon'ble Commission and appeals against the same are pending before the APTEL.as force majeure event arising due to "adverse weather condition…100 years". This will lead to frivolous claims and litigation by misinterpreting these	**Proviso to be added to 3(79):** *Provided that the extension of life of the projects beyond the completion of their useful life shall be subject to fresh consent of the beneficiaries being obtained and furnished.* **Add Proviso to Regulation 3(31):** **Provided that Third Party Sampling**

<table>
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<tr><td>(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or
(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or
(c) Industry wide strikes and labour disturbances having a nationwide impact in India;
(d) Delay in obtaining statutory approval for the project except where the delay is attributable to project developer;

(79) 'Useful life' in relation to a unit of a generating station, integrated mines, transmission system and communication system from the date of commercial operation shall mean the following:

<table>
<tr><td>(a)</td><td>Coal/Lignite based thermal generating station</td><td>25 years</td></tr>
<tr><td>(b)</td><td>Integrated Mine of thermal</td><td>As</td></tr>
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</td><td>words which are subject to various interpretation.
c) When the words "exceptionally …100 years" are already subject to dispute and litigation any such provision would only lead to mis-interpretation and frivolous litigation.
Hence, these words are required to be omitted/ deleted.

• Regulation 3(26)(d) recognises 'Delay in obtaining statutory approval for the project except where the delay is attributable to project developer' as a force majeure. This is a welcoming provision as the project developer would have to take all necessary and proactive steps for "obtaining" statutory approval, otherwise the delay would not be condoned. However, there should be some guiding factors/parameters and/or illustrations for this clause to avoid abuse of this provision.</td><td>agencies shall not have vested interest in Generating Companies/coal supplier

Proposed Definitions:

(a) "Method for measurement of GCV": Method for measuring GCV should be on "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.
(b) "GCV as billed":Means the GCV of coal as determined for billing purpose as per which the generator pays to the coal supplier. GCV of Coal or lignite as measured at Coal mine, mined from any seam or section of a seam in the Suppliers' collieries from which Coal is produced and supplied to Generating Companies.

Provided that measurement of coal or lignite shall be carried out through Third Party sampling to be appointed by the generating companies in accordance with</td></tr>
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<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
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<tr><td></td><td>generating station</td><td>per approved Mining Plan</td></tr>
<tr><td>(c)</td><td>Gas/Liquid fuel based thermal generating station</td><td>25 years</td></tr>
<tr><td>(d)</td><td>AC and DC sub-station</td><td>25 years</td></tr>
<tr><td>(e)</td><td>Gas Insulated Substation (GIS)</td><td>25 years</td></tr>
<tr><td>(f)</td><td>Hydro generating station including pumped
Storage hydro generating stations</td><td>40 years</td></tr>
<tr><td>(g)</td><td>Transmission line (including HVAC & HVDC)</td><td>35 years</td></tr>
<tr><td>(h)</td><td>Communication system</td><td>15 years</td></tr>
</table>

Provided that the extension of life of the projects beyond the completion of their useful life shall be decided by the Commission on case to case basis;
</td>
<td></td>
<td>guidelines, if any, issued by Central Government.
Provided that Third Party Sampling agencies shall not have vested interest in Coal Suppliers/Generators.
Provided Losses between the "GCV billed" and "GCV received" is separatelyby Commission.

(c) 'Non-Tariff Income for transmission business' means income incidental to the licensed business other than the income from tariff.
(d) 'Non-Tariff Income for generation business' means the amount of non-tariff income relating to the Generation Business as approved by the Commisison shall be deducted from the Annual Fixed Charges in determining the Net Annual Fixed Charges of the Generation Company. Provided that the Generation Company shall submit</td>
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Draft Regulations	Comments/Rationale	Proposed Regulations
	<u>Draft Regulation 3(79):</u> Extension of life may be granted upon furnishing of fresh consent of the beneficiaries. The same is imperative since the beneficiaries must ultimately bear the cost	full details of its forecast of non tariff income to the Commisison in such form as may be stipulated by the Commission from time to time. The indicative list of various heads to be considered for non tariff income shall as as under: a) Income from rent of land or buildings; b) Income from sale of scrap; c) Income from statutory investments; d) Income from sale of Ash/rejected coal; e) Interest on delayed or deferred payment on bills; f) Interest on advances to suppliers/contractors; g) Rental from staff quarters; h) Rental from conractors; i) Income from hire charges from contractors and others; j) Income from advertisements, etc; k) Late payment surcharge and income from sale of scrap. l) Any other non-tariff income.

Draft Regulations	Comments/Rationale	Proposed Regulations
	of power purchase from old stations. • Further, there have been various instances where power purchase cost from expensive old station have been disallowed by the respective State Commissions of the beneficiaries. Therefore, in view of the above, a proviso must be added for obtaining fresh consent of the beneficiaries in case extension of life is sought. Similiar to the case of Maha-Genco before Maharashtra Commission. • Merit Order Scheduling of power during such cases should be defined as this may lead to various discrepancies. • **Draft Regulation 3(31):** Hon'ble Commission has provided for a definition for "*GCV as received*", at the unloading point. Further, Third Party sampling agencies should not have any vested interest in the Generating Companies. • Hon'ble Commission in the Explanatory Memorandum to Draft Regulations has referred to Consultation Paper and observed as under: ***"22.4 The "GCV As Billed" is indicative of total energy content dispatched by the suppliers and normally paid for by the recipient stations***. *The "GCV As Received" is expected to be same as "GCV As Billed" barring minor transit losses.*	

Draft Regulations	Comments/Rationale	Proposed Regulations
	"GCV As Fired" is computed at the time of actual use of coal in the generating unit for power generation. For a coal consignment, "GCV As Fired" would be equal to "GCV As Received" minus the heat loss due to storage, as coal may undergo certain quality changes/degradation over the storage periods." • As evident from above, as per Hon'ble Commission there should not be any difference between "GCV as billed" and "GCV as received", barring minor transit losses. However, there have been instances where the "GCV as billed" and "GCV as received" where there has been huge differences, primarily on account of non- Standardization of Methodology while measuring "GCV as billed" and "GCV as received", which was also pointed out in the Report of the Comptroller and Auditor General of India dated 01.12.2016 on Fuel Management of Coal Based Power Stations of NPTC Ltd***("CAG Report")*** as well as in the Consultation Paper issued by this Hon'ble Commission prior to issuance of Draft Tariff Regulations. It is therefore necessary that there should be a definition for: (i) ***"Method for measurement of GCV":*** (ii) ***"GCV as billed*** • Losses between the "GCV billed" and "GCV received" should be quantified like normal losses and abnormal	

Draft Regulations	Comments/Rationale	Proposed Regulations
	losses. **<u>Non-Tariff Income</u>** • Apart from the above, there is a need to define Non-Tariff Income for Gencos and Transcos since, the benefit of items which can be categorised as non-tariff income must be reduced from the ARR of the generating companies and transmisison licensees for the benefit of the ultimate retail consumers of the distribution licensees. For example late payment surcharge (LPSC) which is a nontariff income must be reduced from the ARR of the genereating company and the transmission company.	
10. Determination of tariff: (1) The generating company or the transmission licensee, as the case may be, shall file petition before the Commission as per **Annexure-I** of these regulations containing the details of underlying assumptions for the capital expenditure and additional capital expenditure incurred and projected to be incurred, wherever applicable. (2) If the petition is inadequate in any respect as required under Annexure-I of these regulations,		

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the application shall be returned to the generating company or transmission licensee, as the case may be, for resubmission of the petition within one month after rectifying the deficiencies as may be pointed out by the staff of the Commission. (3) If the information furnished in the petition is in accordance with these regulations and is adequate for carrying out prudence check of the claims made, the Commission may consider to grant interim tariff in case of new projects. (4) In case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the long term customers at the tariff approved by the Commission and applicable as on 31.3.2019 for the period starting from 1.4.2019 till approval of final tariff by the Commission in accordance with these regulations: (5) The Commission shall grant final tariff in case of existing and new projects, after considering the replies received from the respondents, and suggestions and objections, if any, received from the general public and any other person permitted by the Commission including the consumers or consumer associations.	**Draft Regulation 10(6):** For the purpose of determination of	(6) The Commission ~~may~~ shall hear the

Draft Regulations	Comments/Rationale	Proposed Regulations
(6) The Commission may hear the petitioner, the respondents and any other person permitted including the consumers or consumer associations while granting interim or final tariff. (7) The difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the bank rate prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments. (8) Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure exceeds the actual additional capital expenditure incurred on year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with interest at 1.20 times of the bank rate as prevalent on 1st April of the respective year.	tariff, the draft regulations provide that a Petition has to be filed in terms of Regulation 10(1) of the draft Regulations. However, in Regulation 10(3) & (5). While granting the interim and final tariff there is no requirement for the commission to grant a hearing to the stakeholder. In Regulation 10(6), the commission has reserved its discretion to hear the stakeholder while granting tariff. In this regard:- (a) Earlier Regulations mandates a hearing while determining the tariff. There appears to be no reason as to why the right of respondents/beneficiaries/stakeholders are being curtailed. (b) Tariff order not only concerns the petitioner, it has a direct bearing on the beneficiaries of the Petitioner. In essence the rights and obligations of the beneficiaries are decided in such proceedings. Hence, denying the right of hearing to beneficiaries is a clear violation of the principles of natural justice. (c) Stakeholders must be made a part of tariff determination as the tariff is ultimately passed on the beneficiaries. Uusally, consumeres/consumer body does not appear in the various genereation and transmisison tariff proceedings/hearings before the Hon'ble Commission whereas the fact of the matter is that the generation and	petitioner, the respondents, the beneficiaries, authorised consumer representatives and any other person permitted including the consumers or consumer associations while granting interim or final tariff.

Draft Regulations	Comments/Rationale	Proposed Regulations
(9) Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure falls short of the actual additional capital expenditure incurred by more than 10% on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case may be, the shortfall in tariff corresponding to difference in additional capital expenditure, as approved by the Commission, along with interest at the bank rate as prevalent on 1st April of the respective year.	transmission tariff ultimately affects the retail consumers as these tariff are passed through to them through the distribution licensees. Therefore, Hon'ble Commission must ensure that consumers offer their views orally as well as in writing in these proceedings. Therefore, the word '*may*' used in Regulation 10(6) must be replaced by the word '*Shall*'. Further, the terms '*beneficiaries*' and '*authorised consumer representatives*' be included.	
14. Components of Tariff: (1) The tariff for supply of electricity from a thermal generating station shall comprise two parts, namely, capacity charge (for recovery of annual fixed cost consisting of the components as specified in Regulation 51 of these regulations) and energy charge (for recovery of primary and secondary fuel cost and limestone cost where applicable). (2) The supplementary fixed cost for additional capitalization on account of implementation of revised emission standards in the existing generating station or new generating station, as the case may be, shall be determined by the	**Draft Regulation 14(5):** In the consultation paper, Transmission tariff was proposed to be a two part tariff, as under: "***Two Part tariff:*** **1.** *Fixed Charges (FC): Annual Fixed Cost of some of fixed transmission system designated for access and immediate evacuation, Annual Fixed Cost of evacuation transmission system, Part of annual fixed cost consisting of debt service obligations, interest on loans, guaranteed returns* **2.** *Variable Charges (VC): Common transmission system excluding evacuation transmission system; Sum of incremental return, O&M Expenses, Interest on working capital"* (reference: clause 7.5.4-7.5.6)	Transmission tariff should be on two part basis, wherein the first part can be linked with the access service and the second part can be linked with the transmisison service.

Draft Regulations	Comments/Rationale	Proposed Regulations
Commission separately; (3) The energy charge of the generating station shall be determined in accordance with the provisions of Chapter 11 of these Regulations. The input price of coal or lignite from the integrated mine shall form part of energy charge of the generating station. (4) The tariff for supply of electricity from a hydro generating station shall comprise capacity charge and energy charge to be derived in the manner specified in Regulation 54 of these regulations, for recovery of annual fixed cost (consisting of the components referred to in Regulation 15 of these regulations) through the two charges. (5) The tariff for transmission of electricity on inter-State transmission system shall comprise transmission charges for recovery of annual fixed cost consisting of the components specified in Regulation 15 of these regulations.	However, Hon'ble Commission in the Draft Regulations has only proposed for Capacity charges under Regulation 15 and not variable charges. There are no reasons provided for not providing a two-part tariff for Transmission. It is a fact that single part tariff structure provides for transmission costs irrespective of actual transactions or transmission service. In short term or medium term access, market participants may seek access to transmission system but not necessarily avail transmission service unless there is actual transaction. Hence, it is imperative that the access service be provided for independent of the quantity for which transmission service is availed. The single part traiff structure does not meet this requirement	
15. Capacity Charges: The Capacity charges shall be derived on the basis of annual fixed cost. The annual fixed cost (AFC) of a generating station or a transmission system including communication system shall consist of the following components: (a) Depreciation;	**Draft Regulation 15: The Hon'ble Commission has adopted this regulation from the earlier Tariff Regulations, 2014.** Electricity Act mandates promotion of competition and suitably incorporating risk and reward scenario. As per Draft Regulation 76, the Tariff is ceiling only. Hence, every generator/Transco must try to fall under Merit Order of	**Proposed Regulation 15:** 15. Capacity charges: The Capacity charges shall be derived on the basis of annual fixed cost. The annual fixed cost (AFC) of

Draft Regulations	Comments/Rationale	Proposed Regulations
(b) Return on equity; (c) Interest on loan capital; (d) Interest on working capital; and (e) Operation and maintenance expenses: Provided that special allowance in lieu of R&M, where opted in accordance with Regulation 27 of these regulations, shall be recovered separately and shall not be considered for computation of working capital.	Discoms and achieve higher PLF (market share). It is proposed to have the Capacity charges derived on the basis of annual fixed cost. The annual fixed cost (AFC) of generating station or a transmission system including communication system shall consist of the following two components: 1. Availability Basis: a) Interest on loan b) Depreciation c) Return on equity ROE% (equivalent to Wt. avg. actual loan rate) d) Operation and Maintenance expenses (equivalent to Employee cost only). 2. PLF/Capacity utilization: a) Return on Equity (ROE) balance% (Roe % as per regulation less Wt Avg Loan rate). b) Operation and Maintenance expenses balance. c) Interest on working capital. d) Less: Non Tariff Income	generating station or a transmission system including communication system shall consist of the following two components: 1. Availability Basis: a) Interest on loan b) Depreciation c) Return on equity ROE% (equivalent to Wt. avg. actual loan rate) d) Operation and Maintenance expenses (equivalent to Employee cost only). 2. PLF/Capacity utilization: a) Return on Equity (ROE) balance% (Roe % as per regulation less Wt Avg Loan rate). b) Operation and Maintenance expenses balance. c) Interest on working capital. d) Less: Non Tariff Income
16. Variable Charges or Energy Charges: Energy charges shall be derived on the basis of the landed fuel cost (LFC) or variable cost of a generating station (excluding hydro) and shall	**Draft Regulation 16:** This Regulation considers the cost of fuel for determining the Variable charges or energy charges. However, the variable charges or energy charges not only depend on fuel cost but also on the quality and quantity of fuel	**Variable Charges or Energy Charges:** Energy charges shall be derived on the basis of the landed fuel cost (LFC) or variable cost of a generating station

Draft Regulations	Comments/Rationale	Proposed Regulations
consist of the following cost: (a) Landed Fuel Cost of primary fuel; and (b) Cost of secondary fuel oil consumption: Provided that any refund of taxes and duties along with any amount received on account of penalties from fuel supplier shall have to be adjusted in fuel cost. Provided further that the methodology of determination of supplementary energy charges, if any on account of implementation of revised emission standards in case of a thermal generating station shall be determined separately by the Commission;	supplied. BSES without prejudice to its stand in pending proceedings on this issue in various fora states that: (a) GCV (As billed), quantity (As billed) and cost of fuel (As billed) are also the factor effecting Variable Charges and should also be considered for computation of variable cost. (b) As per the CAG report as well as CEA there would be minor loss of GCV in as billed to as received to as fired value: Para 5.2 of CAG report : *"5.2 Reduction in heat value (GCV) of coal……It was observed that GCV of coal progressively decreased from the 'as billed' stage to the 'as fired' stage, though as per CEA, the three GCV values, i.e., GCV 'as billed', 'as received' and 'as fired' should be approximately same barring minor losses due to storage……"* Therefore there must be a minor difference between as loaded and as received GCV values. (c) CEA also prescribed loss of GCV in its Recommendation on operational norms of Thermal Power stations tariff Period 2014-2019 as under; *"…..Para 13.4 It may be pertinent to mention that the* ***billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as***	(excluding hydro) and shall consist of the following cost: (a) Landed Fuel Cost of primary fuel by considering GCV (As Billed); and (b) Cost of secondary fuel oil consumption:

Draft Regulations	Comments/Rationale	Proposed Regulations
	"as received GCV"). *Considering the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and as received GCV; however, difference between the as received GCV vis-à-vis "as fired GCV" would be very marginal and would be solely on account of marginal loss of heat during the coal storage…* (d) Further, the MoP has proposed 3rd party sampling. However the Genco's need to be directed to share the test reports of the coal as submitted by the 3rd part agencies to the beneficiaries as well as publish the same on their website. The 3rd party sampling procedure also need to involve the representatives of the beneficiaries to verify the independence and correctness of 3rd party sampling. (e) FSA with the coal companies provide for the delivery point to the Generator at the mine end. Hence once the property in goods passes to the Generator, it is the Generator which is liable to account for any drop in GCV thereafter, Hence the GCV as recorded at the mine end minus the existing normative transportation losses must be considered for billing to the beneficiaries. (f) Further the normative loss as per CEA report is of 80 Kcal as prescribed for 30 days storage kept as inventory	

Draft Regulations	Comments/Rationale	Proposed Regulations
	in the plant. Similarly, if the time taken for loading and transportation from the colliery to the plant takes 10 days' time another about 25 Kcal normative loss in GCV can be added. Therefore, if the billed GCV is 5500 Kcal then the GCV to be used for computation of energy charges to be considered as 5395 (5500-80-25) Kcal. (g) Therefore, in terms of the above, GCV (As Billed) must be taken into consideration while arriving at the Energy Charges. Further, BSES Discoms had raised similar concerns in the consultation paper. However, it appears that the same were not considered by this Hon'ble Commission. It is to be understood that the Energy Charges has to be representative of the actual quantity and quality of fuel utilised by the plant. These Regulations must take into account the inefficiencies involved in the handling of coal. Further, it must be ensured that such inefficiencies must not be passed on to the beneficiaries. Also, Losses between the "GCV billed" and "GCV received" should be quantified like normal losses and abnormal losses	
17. Debt-Equity Ratio: (1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. If the		

Draft Regulations	Comments/Rationale	Proposed Regulations
equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan: Provided that: i. where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff: ii. the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment: iii. any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt : equity ratio. **Explanation**-The premium, if any, raised by the generating company or the transmission licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, only if such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station or the transmission system. (2) The generating company or the transmission		

Draft Regulations	Comments/Rationale	Proposed Regulations
licensee shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the generating station or the transmission system including communication system, as the case may be. (3) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2019 shall be considered. (4) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2019, the Commission shall approve the debt: equity ratio in accordance with clause (1) of this Regulation. (5) Any expenditure incurred or projected to be incurred on or after 1.4.2019 as may be admitted	**Draft Regulation 17(6):** In the draft regulations the	

Draft Regulations	Comments/Rationale	Proposed Regulations
by the Commission as additional capital expenditure for determination of tariff, and renovation and modernisation expenditure for life extension shall be serviced in the manner specified in clause (1) of this Regulation. (6) In case of generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity till the generating station continues to generate and supply electricity to the beneficiaries.	accumulated depreciation after completion of useful life, shall be utilized for reduction of Equity. However, in case, the loan is still pending at the end of useful life, the same will be firstly utilized for payment of loan and not for reduction of equity, to avoid any further profits to generating company It is therefore, proposed that utilization of accumulated depreciation after completion of useful life should be equally divided and utilized towards deduction of equity as well as repayment of loans.	
21. Controllable and Uncontrollable factors: The following shall be considered as controllable and uncontrollable factors leading to cost escalation, IDC and IEDC of the project : (1) The "controllable factors" shall include but shall not be limited to the following: a. Efficiency in the implementation of the project		

Draft Regulations	Comments/Rationale	Proposed Regulations
not involving approved change in scope of such project, change in statutory levies or change in law or force majeure events; and b. Delay in execution of the project on account of contractor, supplier or agency of the generating company or transmission licensee. (2) The "uncontrollable factors" shall include but shall not be limited to the following: a. Force Majeure events; b. Change in law; and c. Time and cost over-runs on account of land acquisition except where the delay is attributable to the generating company or the transmission licensee;	**Draft Regulation 21(2)(c)** includes '*Time and cost over-runs on account of land acquisition except where the delay is attributable to the generating company or the transmission licensee;*' as an uncontrollable factor. The said parameter was not a part of the earlier regulations. In this regard, it is suggested that including such a parameter is not in the interest of timely commissioning of projects. The generator should put sincere effort to execute project and consumer should not bear such cost, as:- (a) If the same is included as an uncontrollable factor, it would result in frivolous claims by the developer. (b) Hon'ble Commission while drafting earlier Tariff Regulation for 2014-19 period has rejected the claim of	**Deletion of Regulation 21(2) (c).** **In the alternative, there should be some illustrations to provide for basic parameters for delay in acquisition of land etc., which are legitimate so as to avoid frivolous claims of Gencos and Transcos.**

Draft Regulations	Comments/Rationale	Proposed Regulations
	including land acquisition related delays as an uncontrollable factor claiming that the land is acquired before the financial closure or before the infusion of debt funds. In fact, the acquisition of land is also one of the pre-disbursement conditions by Lenders for disbursement of debt funds. (c) Therefore, there is no reason as to why the same must be included in the regulations. Delay due to land acquisition must be considered on a case to case basis. The Hon'ble Commission should not make a specific provision for the same in the Regulations. (d) It is the generator's obligation to arrange for land and the delay in doing so cannot in any manner be passed on to the consumers. This is a commercial risk which generator must assume in ordinary course of business. Further, even if such a clause is included, the regulations must specify specific parameters so as to avoid frivolous claims and unwarranted litigation. For instance, where the land has been offered and the Generator has left out or failed to take possession of the same. Reliance is placed on the ***Judgment dated 16.09.2015 of the Hon'ble APTEL in Appeal No. 117 of 2014.***	
028. Special Provision for thermal generating	**Draft Regulation 28:** This regulation is the need of the hour,	**Add proviso to Regulation 28 (2):**

Draft Regulations	Comments/Rationale	Proposed Regulations
station which have completed 25 years of operation from commercial operation date: (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement where the total cost inclusive of the fixed cost and the variable cost for the generating station as determined under these regulations, shall be payable on scheduled generation instead of the pre-existing arrangement of separate payment of fixed cost based on availability and energy charge based on schedule. (2) The beneficiary will have the first right of refusal and upon its refusal to enter into an arrangement as above the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit.	wherein Hon'ble Commission has sought to balance the commercial interests of the Gencos and beneficiary. However, to bring down the cost/Tariff for end consumer, the regulation must further encompass option for not selling electricity at a price below the price first quoted to the beneficiary.	*Provided that the generator shall not sell electricity at a price below the price quoted to the beneficiary.*
30. Return on Equity: (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with Regulation 17 of these regulations. (2) Return on equity shall be computed at the base rate of 15.50% for thermal generating station,	In order to adhere to the timelines and timely construction of the project. The return on equity in respect of additional capitalization before and after cut-off date within or beyond the original scope shall be computed at the weighted average	

Draft Regulations	Comments/Rationale	Proposed Regulations
transmission system including communication system and run of the river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run of river generating station with pondage: Provided that: i. Return on equity in respect of additional capitalization after cut off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system; ii. in case of a new project, the rate of return shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;	rate of interest on actual loan portfolio of the generating station or the transmission system; Rate of return on equity shall be limited to wt. avg. loan in case of time overrun and cost overrun. It will encourage generator for timely completion of project.	

Draft Regulations	Comments/Rationale	Proposed Regulations
iii. in case of existing generating station, as and when any of the requirements under proviso ii of this Regulation are found lacking based on the report submitted by the respective RLDC, rate of return shall be reduced by 1.00% for the period for which the deficiency continues.		
32. Interest on loan capital: (1)The loans arrived at in the manner indicated in Regulation 17 of these regulations shall be considered as gross normative loan for calculation of interest on loan. (2) The normative loan outstanding as on 1.4.2019 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2019 from the gross normative loan. (3) The repayment for each of the year of the tariff period 2019-24 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative		

Draft Regulations	Comments/Rationale	Proposed Regulations
repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered upto the date of de-capitalisation of such asset. (4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year. (5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized: Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered: Provided further that if the generating station or		

Draft Regulations	Comments/Rationale	Proposed Regulations
the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered. (6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest. (7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing. (8) In case of dispute, any of the parties may make an application in accordance with the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute: Provided that the beneficiaries or the long term transmission customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of	**Draft Regulation 32 (6):** It should be wt. avg rate of interest for Long term only and not short term loans.Since this component pertains to capital expenditures which are financed by long term loans with lower interest cost, hence we recommend that only long term rate of interest may be used.	**It is proposed that a proviso may be added after Regulation 32(6) as under:** *Provided that the such interest shall only be applicable on long-term loans and not short-term loans.*

Draft Regulations	Comments/Rationale	Proposed Regulations
re-financing of loan.		
33. Depreciation: (1) Depreciation shall be computed from the date of commercial operation of a generating station or unit thereof or a transmission system including communication system. In case of the tariff of all the units of a generating station or a transmission system including communication system for which a single tariff needs to be determined , the depreciation shall be computed from the effective date of commercial operation of the generating station or the transmission system taking into consideration the depreciation of individual units. Provided that effective date of commercial operation shall be worked out by considering the actual date of commercial operation and installed capacity of all the units of the generating station or capital cost of all elements of the transmission system, for which single tariff needs to be determined. (2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements		

Draft Regulations	Comments/Rationale	Proposed Regulations
of transmission system, weighted average life for the generating station of the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis. (3) The salvage value of the asset shall be considered as 5% and depreciation shall be allowed up to maximum of 95% of the capital cost of the asset: Provided that the salvage value for IT equipment and software shall be considered as NIL and 100% value of the assets shall be considered depreciable. Provided further that in case of hydro generating station, the salvage value shall be as provided in the agreement, if any, signed by the developers with the State Government for development of the Plant: Provided also that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall	**<u>Draft Regulation 33(3):</u>** Hon'ble Commission should increase the salvage value up to maximum 90%. It is similar to previous year Tariff Regulations. Draft regulations provide that the salvage value of the asset shall be considered as 5% and depreciation shall be allowed up to maximum of 95% of the capital cost of the asset. Hon'ble Commission by Explanatory Memorandum has observed as under: *"5.5.1….The Commission proposed to reduce the salvage value of the assets from 10% to 5%, thereby increasing the depreciable value of assets from 90% to 95%, in line with the provisions of the Companies Act, 2013."* As per clause 5.5.1 of Explanatory Memorandum Hon'ble commission has lowered the salvage value for all generating & transmission companies to offset the impact of increase in useful. However, useful life of thermal plants (coal & gas fired) and transmission life has not been increased. Hon'ble Commission cannot pick and chose a provision of a statute to align Regulations. If there is a statute the same has to be considered as a whole and not piecemeal. Hence this reduction	(3) The salvage value of the asset shall be considered as ~~5%~~ 10% and depreciation shall be allowed up to maximum of ~~95%~~ 90% of the capital cost of the asset:

Draft Regulations	Comments/Rationale	Proposed Regulations
correspond to the percentage of sale of electricity under long-term power purchase agreement at regulated tariff: Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life and the extended life. (4) Land other than the land held under lease and the land for reservoir in case of hydro generating station shall not be a depreciable asset and its cost shall be excluded from the capital cost while computing depreciable value of the asset. (5) Depreciation shall be calculated annually based on Straight Line Method and at rates specified in **Appendix-I** to these regulations for the assets of the generating station and transmission system: Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the effective date of commercial operation of the station shall be spread over the balance useful life of the assets. (6) In case of the existing projects, the balance	in salvage value would invariably increase the FC burden for beneficiaries of thermal generating plants and transmission companies	

Draft Regulations	Comments/Rationale	Proposed Regulations
depreciable value as on 1.4.2019 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2019 from the gross depreciable value of the assets. (7) The generating company or the transmission license, as the case may be, shall submit the details of proposed capital expenditure five years before the completion of useful life of the project along with justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure. (8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the decapitalized asset during its useful services.		
34. Interest on Working Capital: (1) The working capital shall cover:		**Proposed Regulation 34(a)(i)** 34(a) (i) Cost of coal or lignite and

Draft Regulations	Comments/Rationale	Proposed Regulations
(a) Coal-based/lignite-fired thermal generating stations (i) Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower; (ii) Advance payment for 30 days towards Cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor; (iii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil; (iv) Maintenance spares @ 20% of operation and maintenance expenses specified in Regulation 35 of these regulations;	**Draft Regulation 34 (1) (a) (v)** envisages that the working capital shall cover cost of coal for 15 days for pit-head generating stations and 20 days for non-pit head generating station for generation corresponding to the normative annual plant availability factor or the maximum coal storage capacity whichever is lower. In this regard, it is **proposed that** Cost of coal allowed should be 7 days for pit head generating stations and 10 days for non-pit head generating stations, as:- (a) As stock of fuel is considered for Working Capital, a fresh benchmark may be fixed or actual stock of fuel may be taken. (b) Admittedly, as per the CEA website, there have been several instances in the past where the generating station does not have sufficient coal for stock of 15/20 days. The same is evident from actual average fuel stock extracted by this Hon'ble Commission in the Explanatory Memorandum at Para 13.5.2. (c) Most generating companies do not have sufficient coal stock. Hence, the working capital allowed to them shall be appropriately reduced to be representative of the actual stock. (d) Despite observing low stock of fuel with the generating station, the draft regulations provide a higher working capital. Therefore, in view of the above, the working capital must be	limestone towards stock, if applicable, for ~~15 days~~ 7 days for pit-head generating stations and ~~20 days~~ 10 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;

Draft Regulations	Comments/Rationale	Proposed Regulations
(v) Receivables equivalent to 45 days of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor; and (vi) Operation and maintenance expenses for one month. **(b) Open-cycle Gas Turbine/Combined Cycle thermal generating stations** (i) Fuel cost for 30 days corresponding to the normative annual plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel; (ii) Liquid fuel stock for 15 days corresponding to the normative annual plant availability factor, and in case of use of more than one liquid fuel, cost of main liquid fuel duly taking into account mode of operation of the generating stations of gas fuel and liquid fuel; (iii) Maintenance spares @ 30% of operation and maintenance expenses specified in Regulation 35	reduced to 7 days for pit head generating stations and 10 days for non-pit head generating stations.	

Draft Regulations	Comments/Rationale	Proposed Regulations
of these regulations; (iv) Receivables equivalent to 45 days of capacity charge and energy charge for sale of electricity calculated on normative plant availability factor, duly taking into account mode of operation of the generating station on gas fuel and liquid fuel; and (v) Operation and maintenance expenses for one month. **(c) Hydro generating station (including pumped storage hydro electric generating station) and transmission system:** (i) Receivables equivalent to 45 days of annual fixed charges; (ii) Maintenance spares @ 15% of operation and maintenance expenses specified in Regulation 35 of these regulations; and (iii) Operation and maintenance expenses for one month. (2) The cost of fuel in cases covered under sub-		

Draft Regulations	Comments/Rationale	Proposed Regulations
clauses (a), (b) and (c) of clause (1) of this Regulation shall be based on the landed cost incurred (taking into account normative transit and handling losses) by the generating station and gross calorific value of the fuel as per actual weighted average for the third quarter of preceding financial year in case of each financial year for which tariff is to be determined. Provided that in case of new generating station, the cost of fuel for the first financial year shall be considered based on landed cost incurred (taking into account normative transit and handling losses) and gross calorific value of the fuel as per actual weighted average for three months, as used for infirm generation, preceding date of commercial operation for which tariff is to be determined. (3) Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2019 or as on 1st April of the year during the tariff period 2019-24 in which the generating station or a unit thereof or the transmission system including communication system or element thereof, as the case may be, is declared under commercial operation, whichever		

Draft Regulations	Comments/Rationale	Proposed Regulations
is later: Provided that in case of truing-up, the rate of interest on working capital shall be considered at bank rate as on 1st April of each of the financial year during the tariff period 2019-24; (4) Interest on working capital shall be payable on normative basis notwithstanding that the generating company or the transmission licensee has not taken loan for working capital from any outside agency.		
35. Operation and Maintenance Expenses: (1) **Thermal Generating Station:** Normative Operation and Maintenance expenses of thermal generating stations shall be as follows: (1) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations or units referred to in clauses (b) and (d): (in Rs Lakh/MW)		

Draft Regulations	Comments/Rationale	Proposed Regulations
<table><tr><th>Year</th><th>200/210/250 MW Series</th><th>300/330/350 MW Series</th><th>500 MW Series</th><th>600 MW Series</th><th>800 MW Series and above</th></tr><tr><td>FY 2019-20</td><td>30.59</td><td>24.22</td><td>20.38</td><td>17.39</td><td>15.65</td></tr><tr><td>FY 2020-21</td><td>31.57</td><td>24.99</td><td>21.03</td><td>17.94</td><td>16.15</td></tr><tr><td>FY 2021-22</td><td>32.58</td><td>25.79</td><td>21.71</td><td>18.52</td><td>16.66</td></tr><tr><td>FY 2022-23</td><td>33.62</td><td>26.62</td><td>22.40</td><td>19.11</td><td>17.20</td></tr><tr><td>FY 2023-24</td><td>34.69</td><td>27.47</td><td>23.12</td><td>19.72</td><td>17.75</td></tr></table> Provided that where the date of commercial operation of any additional unit(s) of a generating station after first four units occurs on or after 1.4.2019, the O&M expenses of such		

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additional unit(s) shall be admissible at 90% of the operation and maintenance expenses as specified above;
Provided that Operation and maintenance of generating station and the transmission system of Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project(SSP) shall be determined after taking into account provisions of the Punjab Reorganization Act, 1996 and Narmada Water Scheme, 1980 under Section 6-A of the Inter-State Water Disputes Act, 1956 respectively.

2) Talcher Thermal Power Station (TPS), Tanda TPS and Chandrapura TPS Unit 1 to 3 and Durgapur TPS Unit 1 of DVC:
(in Rs Lakh/MW)
<table>
<tr><th>Year</th><th>Talcher TPS</th><th>Chandrapura TPS (Units Durgapur TPS(Unit 1)</th></tr>
<tr><td>FY 2019-20 to FY 2023-24</td><td>54.78</td><td>45.35</td></tr>
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Draft Regulation 35(3) provides Rs. 25 lakh/MW as O&M Expenses for Advance F class Machines. In tis regard it is proposed that the O&M Expenses for Advance F class Machines be reduced to Rs. 8 lakh/MW, as:
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Proposed Table for O&M Expenses for Advance F Class Machines:
(3) Open Cycle Gas Turbine/Combined Cycle
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(3) Open Cycle Gas Turbine/Combined Cycle generating stations:
(in Rs Lakh/MW)
<table>
<tr><th>Gas Turbine / Combined Cycle generating stations other than small gas</th><th>Small gas turbine power generating stations</th><th>Agartala GPS</th><th>Advance F Class Machines</th></tr>
</table>
</td>
<td>
(a) The same is much higher than the actual O&M costs of such Power Plants and the same will lead to additional tariff burden on the consumers of the beneficiaries.
(b) That the said cost ought to be reduced to Rs. 8 lakh/MW as the same is a fair estimation of the O&M expenses for such plants.
(c) For instance, Pragatri Power Corporation Limited's PPCL-III has Advance F class Machines, and supplies power to BRPL. As per actual Audited accounts of PPCL-III, O&M Expenses works out to be approx. Rs.8 Lacs/MW., Further the cost of O&M Expenses is decreasing from FY 2013-14 to FY 2014-15 Details are Tabulated below:
<table>
<tr><th>Particulars</th><th></th><th>FY 14</th><th>FY 13</th></tr>
<tr><td>Employee</td><td>A</td><td>4784</td><td>3819</td></tr>
<tr><td>Admin</td><td>B</td><td>8701</td><td>12237</td></tr>
<tr><td>Total O&M</td><td>C=A+B</td><td>13485</td><td>16056</td></tr>
<tr><td>Pragati -1 Capacity (MW)</td><td>D</td><td>330</td><td>330</td></tr>
<tr><td>Bawana Capacity (MW)</td><td>E</td><td>1371</td><td>1371</td></tr>
<tr><td>Capacity (MW)</td><td>F=E+D</td><td>1701</td><td>1701</td></tr>
<tr><td>O&M/Capacity</td><td>G=F/C</td><td>7.93</td><td>9.44</td></tr>
</table>
</td>
<td>
generating stations:
(in Rs Lakh/MW)
<table>
<tr><th>Advance F Class Machines</th></tr>
<tr><td><s>25.00</s> 8.00</td></tr>
<tr><td><s>25.80</s> 8.00</td></tr>
<tr><td><s>26.63</s> 8.00</td></tr>
<tr><td><s>27.48</s> 8.00</td></tr>
<tr><td><s>28.35</s> 8.00</td></tr>
</table>
</td>
</tr>
</table>

Draft Regulations	Comments/Rationale	Proposed Regulations
turbine power generating stations | | | 16.24 | 34.38 | 41.00 | 25.00 16.76 | 35.48 | 42.31 | 25.80 17.30 | 36.62 | 43.66 | 26.63 17.85 | 37.79 | 45.06 | 27.48 18.42 | 39.00 | 46.50 | 28.35 (4) Lignite-fired generating stations: (in Rs Lakh/MW) **Year** | **125 MW Sets** | **TPS-I NLC** FY 2019- | 29.29 | 40.01	**Bawana's O&M/MW** | **H=E/F*G** | **6.39** | **7.61** *[SOURCE: As per Audited accounts of Pragati Power Corporation FY 2013-14]* Therefore, in view of the above, the O&M Expenses for Advance F Class Machines should be reduced after analysing and comparing the actual O&M Expenses having Advance F Class Machines.	

Draft Regulations	Comments/Rationale	Proposed Regulations

20			
FY 2020-21	30.23	41.29	
FY 2021-22	31.20	42.61	
FY 2022-23	32.20	43.97	
FY 2023-24	33.23	45.38	

(5) Generating Stations based on coal rejects:
(in Rs Lakh/MW)

Year	**O&M Expenses**
FY 2019-20	29.29
FY 2020-21	30.23
FY 2021-22	31.20
FY 2022-23	32.20
FY 2023-24	33.23

(6) The Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately prudence check:
Provided that water charges shall be allowed

Draft Regulations	Comments/Rationale	Proposed Regulations
based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check. The details regarding the same shall be furnished along with the petition: Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses;. Provided also that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance or special allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization. **(2) Hydro Generating Station:** (a) Following operations and maintenance expense norms shall be applicable for hydro generating stations which have been operational for three or more years as on 01.04.2019 subject to maximum of 4% of admitted capital cost as on commercial date of the respective year: (in Rs Lakh/MW)		

Draft Regulations	Comments/Rationale	Proposed Regulations
(table below)		

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
THDC Stage I	27,764.25	29,079.74	30,457.56	31,900.66	33,412.14
KHEP	13,441.05	14,077.90	14,744.92	15,443.54	16,175.27
Bairasul	8,267.27	8,658.98	9,069.25	9,498.96	9,949.02
Loktak	9,499.00	9,949.07	10,420.46	10,914.19	11,431.31
Salal	19,162.09	20,070.00	21,020.93	22,016.92	23,060.10
Tanakpur	10,497.35	10,994.73	11,515.66	12,061.29	12,632.76
Chamera-I	11,762.86	12,320.19	12,903.93	13,515.33	14,155.70
Uri I	9,853.43	10,320.30	10,809.28	11,321.43	11,857.85
Rangit	5,332.46	5,585.12	5,849.74	6,126.91	6,417.21
Chamera-II	10,663.32	11,168.55	11,697.73	12,251.98	12,832.48
Dhauliganga	8,784.79	9,201.02	9,636.97	10,093.58	10,571.82
Dulhasti	18,548.58	19,427.43	20,347.92	21,312.02	22,321.80
Teesta-V	12,162.80	12,739.08	13,342.67	13,974.85	14,636.99
Sewa-II	7,074.35	7,409.54	7,760.61	8,128.31	8,513.44
TLDP III	7,534.28	7,891.26	8,265.16	8,656.77	9,066.93
Chamera III	9,072.46	9,502.32	9,952.54	10,424.10	10,918.00

Draft Regulations	Comments/Rationale	Proposed Regulations

Chutak	3,534.00	3,701.44	3,876.82	4,060.51	4,252.90
Nimmo Bazgo	3,524.80	3,691.81	3,866.73	4,049.94	4,241.83
Uri II	7,052.91	7,387.08	7,737.09	8,103.68	8,487.64
Parbati III	6,613.30	6,926.65	7,254.84	7,598.58	7,958.60
Indira Sagar	11,718.28	12,273.50	12,855.03	13,464.11	14,102.05
Omkareshwar	7,192.79	7,533.59	7,890.54	8,264.40	8,655.97
Naptha Jhakari	32,942.98	34,503.84	36,138.66	37,850.94	39,644.34
Koldam	12,652.97	13,252.48	13,880.89	14,538.06	15,226.88
Kopili	12,414.35	13,002.55	13,618.62	14,263.88	14,939.71
Doyang	5,647.85	5,915.45	6,195.73	6,489.29	6,796.75
Ranganadi	12,084.68	12,657.26	13,256.97	13,885.10	14,542.98
Maithon	2,890.00	3,026.93	3,170.35	3,320.56	3,477.89
Panchet	2,189.56	2,293.30	2,401.96	2,515.76	2,634.96
Tilaya	899.43	942.04	986.68	1,033.42	1,082.39

(b) In case of the hydro generating stations declared under commercial operation on or after 1.4.2019, operation and maintenance expenses of

Draft Regulations	Comments/Rationale	Proposed Regulations
first year shall be fixed at 2.5% of the original project cost (excluding cost of rehabilitation & resettlement works, IDC and IEDC) and, in case of hydro generating station which have not completed a period of three years as on 1.4.2019 , operation and maintenance expenses of 2019-20 shall be worked out by applying escalation rate of 4.70% on the applicable operation & maintenance expenses as on 31.3.2019. The operation & maintenance expenses for subsequent years of the tariff period shall be worked out by applying escalation rate of 4.70% per annum. (c) The Security Expenses and Capital Spares for hydro generating stations shall be allowed separately after prudence check: Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses at the time, the details of year wise actual capital spares consumed at the time of truing up with appropriate justification. **(3) Transmission system:** (a) The following normative operation and maintenance expenses shall be admissible for the transmission system:		

Particulars	2019-	2020-	2021-	2022-	2023-

Draft Regulations	Comments/Rationale	Proposed Regulations
(see table below)		

	20	21	22	23	24
Norms for sub-station Bays (Rs Lakh per bay)					
765 kV	42.03	43.37	44.76	46.19	47.67
400 kV	30.02	30.98	31.97	32.99	34.05
220 kV	21.01	21.69	22.38	23.10	23.83
132 kV and below	15.01	15.49	15.99	16.50	17.02
Norms for Transformers (Rs Lakh per MVA)					
765 kV	0.364	0.376	0.388	0.400	0.413
400 kV	0.266	0.275	0.284	0.293	0.302
220 kV	0.182	0.188	0.194	0.200	0.206
132 kV and below	0.182	0.188	0.194	0.200	0.206
Norms for AC and HVDC lines (Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.845	0.872	0.900	0.929	0.959
Single Circuit (Bundled conductor with four or more sub-conductors)	0.725	0.748	0.772	0.796	0.822
Single Circuit (Twin & Triple Conductor)	0.483	0.498	0.514	0.531	0.548
Single Circuit (Single Conductor)	0.242	0.249	0.257	0.265	0.274
Double Circuit (Bundled	1.268	1.309	1.351	1.394	1.439

Draft Regulations						Comments/Rationale	Proposed Regulations
conductor with four or more sub-conductors)							
Double Circuit (Twin & Triple Conductor)	0.845	0.872	0.900	0.929	0.959		
Double Circuit (Single Conductor)	0.362	0.374	0.386	0.398	0.411		
Multi Circuit (Bundled Conductor with four or more sub-conductor)	2.226	2.297	2.371	2.446	2.525		
Multi Circuit (Twin & Triple Conductor)	1.482	1.529	1.578	1.629	1.681		
Norms for HVDC stations							
HVDC Back-to-Back stations (Rs Lakh per 500 MW)	750	774	799	824	851		
Rihand-Dadri HVDC bipole scheme (Rs Lakh)	2,319	2,393	2,469	2,548	2,630		
Talcher- Kolar HVDC bipole scheme (Rs Lakh)	2,564	2,646	2,731	2,818	2,908		
Bhiwadi-Balia HVDC bipole scheme	1,761	1,817	1,875	1,935	1,997		

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>
<table>
<tr><td>Bishwanath-Agra HVDC bipole scheme</td><td>1,329</td><td>1,371</td><td>1,415</td><td>1,460</td><td>1,507</td></tr>
</table>

Provided that operation and maintenance expenses for new HVDC bi-pole scheme for a particular year shall be allowed pro-rata on the basis of normative rate of operation and maintenance expense with reference to similar HVDC bi-pole scheme for the respective year:
Provided further that the O&M expenses norms for HVDC bi-pole line shall be considered as Single Circuit quad AC line;
Provided also that the O&M expenses for the GIS bays and transformers shall be allowed as worked out by multiplying 0.70 of the O&M expenses of the normative O&M expenses for bays and transformers.
(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of sub-station bays, transformer capacity of the transformer (in MVA) and kMs of line length with the applicable norms for the operation and maintenance expenses per bay and
</td><td></td><td></td></tr>
</table>

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>per km respectively.
(4) Communication system: (a) The following norms shall be applicable for calculation of operation and maintenance expenses for the communication system:

(Rs Lakh per Unit)
<table>
<tr><th>Norms for O&M Expenses</th><th>2019-20</th><th>2020-21</th><th>2021-22</th><th>2022-23</th><th>2023-24</th></tr>
<tr><td>Length of OPGW links (Rs Lakh/Km)</td><td>0.069</td><td>0.071</td><td>0.073</td><td>0.076</td><td>0.078</td></tr>
<tr><td>Number of Remote Terminal Units(RTUs)(Rs Lakh/RTU)</td><td>2.16</td><td>2.23</td><td>2.30</td><td>2.37</td><td>2.45</td></tr>
<tr><td>Number of PMU installed (Rs Lakh/PMU)</td><td>0.96</td><td>0.99</td><td>1.02</td><td>1.05</td><td>1.08</td></tr>
</table>

(b) The total admissible O&M expenses for the communication system shall be calculated by multiplying the length of OPGW link (in km), number of remote terminal units (in number) and number of PMU (in number) and with the applicable norms for theoperation and maintenance expenses as specified above.</td><td></td><td></td></tr>
</table>

Draft Regulations	Comments/Rationale	Proposed Regulations
(c) The Security Expenses, Capital Spares and Self insurance reserve for transmission system and associated communication system shall be allowed separately after prudence check: Provided that the transmission licensee shall submit the assessment of the security requirement and estimated expenses, the details of year wise actual capital spares consumed and details of self insurance expenditure at the time of truing up with appropriate justification.		
47. Components of Landed cost of Primary Fuel: The landed cost of primary fuel for any month shall include base price or input price of fuel corresponding to the grade and quality of fuel and inclusive of statutory charges as applicable, transportation cost by rail or road or any other means, and loading, unloading and handling charges. Provided that procurement of fuel at a price other than Government notified prices may be considered, if based on competitive bidding through transparent process, for the purpose of landed fuel cost; Provided further that landed cost of primary fuel shall be worked out based on the actual bill paid	**3rd Proviso to Draft Regulation 47:** envisages third party sampling of coal. Further, the expenses towards third party sampling shall be reimbursed by the beneficiaries. In this regard, BSES Discoms have following concerns:- (a) The Report of third party sampling must be promptly shared with the beneficiaries. Further, the generating companies need to be directed to publish the test reports on their website. (b) Third Party sampling procedure must involve representatives of the beneficiaries **to ensure transparency** and correctness of Third Party sampling. (c) There must be a mechanism in place to determine the independence of Third Party sampling. In view of the above, it is proposed that there should be a detailed Third Party sampling guidelines which shall address	**Third proviso to Regulation 4 may be added as under:** *Provided further that the generating company shall promptly share the report of third party sampling with the beneficiaries in addition to publishing the same on its website. Further, the agency engaged in third party sampling must provide a disclosure regarding any conflict of interest with either the beneficiary or the generating company.*

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>by the generating company including any adjustment on account of quantity and quality;
Provided also that in case of Coal or Lignite thermal generating station, the Gross Calorific Value shall be measured by third party sampling and the expenses towards the third party sampling facility shall be reimbursed by the beneficiaries.</td><td>the above issues including the issue of conflict of interest/vested interest, so as to maintain independence and impartiality of the Third Party agency.</td><td></td></tr>
<tr><td>48. Transit and Handling Losses: The landed cost of coal or lignite during the month shall include the transit and handling losses as per the following norms :-
<table>
<tr><th>Thermal Generating station</th><th>Distance of Generating Station from source of fuel</th><th>Transit and Handling Loss (%)</th></tr>
<tr><td>Pit head</td><td>-</td><td>0.20%</td></tr>
<tr><td>Non-pit head</td><td>Upto 1000 KM</td><td>0.80%</td></tr>
<tr><td></td><td>Above 1,000 KM</td><td>1.20%</td></tr>
</table>
Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit and handling losses applicable for non-pit head station shall apply:
Provided further that in case of imported coal, the transit and handling losses applicable for non-pit head station shall apply.</td>
<td>Draft Regulation 48 provides that the landed cost of coal o lignite during the month shall include the transit and handling losses in case there is a distance of 1000 kms of the generating station from source fuel in case of Non-pit head thermal generating station. In this regard it is submitted that:
(a) The Hon'ble Commission has not provided anyrationale in the explanatory memorandum or the consultation paper for arriving at the distance of 1000 kms. There has to be a rationale for increasing the Transit and handling loss of Non-Pit head stations. The same also applies for Imported Coal as well.
(b) The consultation paper mentions that the earlier clause needs to be modified in terms of the actual data available, however no data has been provided in support of the said calculation of 1000 kms. Further the CEA recommendations issued along with the draft regulations do not mention about the said requirement.</td>
<td>The draft regulation may be amended as under:

48. Transit and Handling Losses: The landed cost of coal or lignite during the month shall include the transit and handling losses as per the following norms:-
<table>
<tr><th>Thermal Generatin g station</th><th>~~Distance of Generating Station from source of fuel~~</th><th>Transit and Handling Loss (%)</th></tr>
<tr><td>Pit head</td><td>-</td><td>0.20%</td></tr>
<tr><td>Non-pit head</td><td>~~Upto 1000 KM~~</td><td>0.80%</td></tr>
<tr><td></td><td>~~Above 1,000 KM~~</td><td>~~1.20%~~</td></tr>
</table>
Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is</td></tr>
</table>

Draft Regulations	Comments/Rationale	Proposed Regulations
	(c) The same is against the interest of the licensee and the above, 1000KM norm should be deleted as there will be unnecessary burden on the consumers. In view of the above, the earlier regulation shall be retained and the norm of 1000 kms should be deleted.	transported to the station through rail, transit and handling losses applicable for non-pit head station shall apply: Provided further that in case of imported coal, the transit and handling losses applicable for non-pit head station shall apply.
49. Computation of Gross Calorific Value: (1) The gross calorific value for computation of energy charges as per Regulation 52 of these regulations shall be done in accordance with GCV on as received basis. (2) The generating company shall provide to the beneficiaries of the generating station the details in respect of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc. as per the forms prescribed at **Annexure-I** to these regulations: Provided that the details of the weighted average GCV of the fuel on as received basis used for generation during the period, blending ratio of the imported coal with domestic coal, proportion of e-auction coal shall be provided separately, along with the bills of the respective month; Provided further that copies of the bills and	1)As per the CAG report as well as CEA there would be minor loss of GCV in as billed to as received to as fired value: Para 5.2 of CAG report : *"5.2 Reduction in heat value (GCV) of coal……It was observed that GCV of coal progressively decreased from the 'as billed' stage to the 'as fired' stage, though as per CEA, the three GCV values, i.e., GCV 'as billed', 'as received' and 'as fired' should be approximately same barring minor losses due to storage……"* Therefore there must be a minor difference between as loaded and as received GCV values. 2) CEA also prescribed loss of GCV in its Recommendation on operational norms of Thermal Power stations tariff Period 2014-2019 as under; *"…..Para 13.4 It may be pertinent to mention that the billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as "as received GCV"). Considering*	(a) ***"Method for measurement of GCV":*** Method for measuring GCV should be on "Air-Dry basis'' for procurement of coal both from domestic and international suppliers. (b) ***"GCV as billed":***Means the GCV of coal as determined for billing purpose as per which the generator pays to the coal supplier. GCV of Coal or lignite as measured at Coal mine, mined from any seam or section of a seam in the Suppliers' collieries from which Coal is produced and supplied to Generating Companies. Provided that measurement of coal or lignite shall be carried out through Third Party sampling to be appointed by the

Draft Regulations	Comments/Rationale	Proposed Regulations
details of parameters of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc., details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal shall also be displayed on the website of the generating company.	*the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and as received GCV; however, difference between the as received GCV vis-à-vis "as fired GCV" would be very marginal and would be solely on account of marginal loss of heat during the coal storage…* 3) Further the MoP has proposed 3rd party sampling. However the Genco's need to be directed to share the test reports of the coal as submitted by the 3rd part agencies to the beneficiaries as well as publish the same on their website. The 3rd party sampling procedure also need to involve the representatives of the beneficiaries to verify the independence and correctness of 3rd party sampling. 4. The FSA with the coal companies provide for the delivery point to the Generator at the mine end. Hence once the property in goods passes to the Generator, it is the Generator which is liable to account for any drop in GCV thereafter, Hence the GCV as recorded at the mine end minus the existing normative transportation losses must be considered for billing to the beneficiaries. 5. Further the normative loss as per CEA report is of 80 Kcal as prescribed for 30 days storage kept as inventory in the plant. Similarly if the time taken for loading and transportation from the colliery to the plant takes 10 days time another about 25 Kcal normative loss in GCV can be added. Therefore is the	generating companies in accordance with guidelines, if any, issued by Central Government. Provided that Third Party Sampling agencies shall not have vested interest in Coal Suppliers/generator. Provided Losses between the "GCV billed" and "GCV received" is separatelyby Commission.

Draft Regulations	Comments/Rationale	Proposed Regulations
	billed GCV is 5500 Kcal then the GCV to be used for computation of energy charges to be considered as 5395 (5500-80-25) Kcal 6.CEA Norms cannot be incorporated. 7. CERC's concept paper where Air-Dry method has been suggested.	
51. Computation and Payment of Capacity Charge for Thermal Generating Stations: (1) The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. Capacity Charge for the month shall be recovered in two parts viz., Capacity Charge for Peak period of the month and Capacity Charge for Off-Peak period of the month. (2) The Capacity Charge rate for Peak hours shall be 25% more than that of Off-Peak hours. The	**Draft Regulation 51(1):** provides that the fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under the Regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. Capacity Charge for the month shall be recovered in two parts viz., Capacity Charge for Peak period of the month and Capacity Charge for Off-Peak period of the month. In this regard it is submitted that as per Electricity Act 2003: *"An Act to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity and generally for taking measures conducive to* *development of electricity industry,* ***promoting competition therein,protecting interest of consumers*** *and supply of electricity*	

Draft Regulations	Comments/Rationale	Proposed Regulations
Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae: $CC_m = \sum_{i=1}^{NDM} CCpdi + \sum_{i=1}^{NDM} CCopdi$ Where, $CC_{pd} = \frac{(AFC)}{(NDY)} x\ WFp$; $CC_{opd} = \frac{(AFC)}{(NDY)} x\ WFop$; and, $WFp = \frac{(1.25\ x\ NHDp\ x\ PAFDp)}{[(1.25\ x\ NPAFp\ x\ NHDp)+(NPAFop\ x\ NHDop)]}$; $WFop = \frac{(NHDop\ x\ PAFDop)}{[(1.25\ x\ NPAFp\ x\ NHDp)+(NPAFop\ x\ NHDop)]}$ Subject to, $CCm \leq \frac{(AFC\ x\ NDM)}{NDY}$; and $\sum_{i=1}^{NDM} CCpdi \leq \frac{(AFC\ x\ NDM)}{(NDY)} x \frac{(1.25\ x\ NPAFp\ x\ NHDp)}{[(1.25\ x\ NPAFp\ x\ NHDp)+(NPAFop\ x\ NHDop}$ $\sum_{i=1}^{NDM} CCopdi \leq \frac{(AFC\ x\ NDM)}{(NDY)} x \frac{(NPAFop\ x\ NHDop)}{[(1.25\ x\ NPAFp\ x\ NHDp)+(NPAFop\ x\ NHDo}$ Where,	*to all areas, rationalization of electricity tariff, ensuring transparent policies regarding subsidies, promotion of efficient and environmentally benign policies, constitution of Central Electricity Authority, Regulatory Commissions and establishment of Appellate Tribunal and for matters connected therewith or incidental thereto."* In order to promote competition and suitably incorporating risk and reward scenario. As per Draft Regulation 76, the Tariff is ceiling only. Hence, every generator/Transco must try to fall under Merit Order of Discoms and achieve higher PLF (market share). It is proposed to have, Capacity charges shall be derived on the basis of annual fixed cost. The annual fixed cost (AFC) of generating station or a transmission system including communication system shall consist of the following two components: (e) Availability Basis: e) Interest on loan f) Depreciation g) Return on equity ROE% (equivalent to Wt. avg. actual loan rate) h) Operation and Maintenance expenses (equivalent to Employee cost only). (f) PLF/Capacity utilization:	*The following definitions can be added:* *(c) 'Non-Tariff Income for transmission business' means income incidental to the licensed business other than the income from tariff.* *(d) 'Non-Tariff Income for generation business'*

Draft Regulations	Comments/Rationale	Proposed Regulations
CCm = Capacity Charge for the month NDM = Number of Days in the month CCpd = Capacity Charge for the peak hours of the day CCopd = Capacity Charge for the off-peak hours of the day AFC = Annual Fixed Cost NDY = Number of Days in the year NHDp = Normative Number of Peak Hours in a Day NHDop = Normative Number of Off-Peak Hours in a Day PAFDp = Plant Availability Factor achieved during the Peak Hours of the Day PAFDop = Plant Availability Factor achieved during the Off-Peak Hours of the Day NPAFp = Normative Plant Availability Factor for Peak Hours of the Day NPAFop = Normative Plant Availability Factor for Off-Peak Hours of the Day WFp = Weightage Factor for Peak period WFop = Weightage Factor for Off-Peak period 3) Normative Plant Availability Factor for "Peak" and "Off-Peak" periods shall be equivalent to the	e) Return on Equity (ROE) balance% (Roe % as per regulation less Wt Avg Loan rate). f) Operation and Maintenance expenses balance. g) Interest on working capital Less: Non Tariff Income **51(2):** The "Peak" or "Off-Peak" The GENCOs are under an **obligation** under the PPA to cater to the demand of the beneficiaries/consumers. For performing their obligations GENCOs are already getting Return on Investments. As such there arises no need for them to etc., incentives for performing their basic obligation. Giving an incentive on an obligation is inadmissible and incorrect model of providing incentives to a generating company. Incentives are linked to overachievement of targets that are set out by the Hon'ble Commission, to improve efficiency of a generating company. Accordingly, there cannot be a double incentive for meeting the obligations as the same will put an additional tariff burden on the ultimate consumers. **51(3):** The "Peak" and "Off-Peak" declared by the RLDC must be in concurrence with the "Peak" and "Off-Peak" declared by SLDC of a particular state. There might be a situation where the "Peak" and "Off-Peak" declared by SLDC of a particular	*means income from any other business other than generation business of the generator.*

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>NQPAF specified in Regulation 59 (A) of these regulations. The number of hours of "Peak" and "Off-Peak" periods in a region shall be declared on monthly basis in advance, by the concerned RLDC and the Peak period in a day shall not be less than 4 hours.
(4) The generating company shall be allowed to recover the monthly Peak period Capacity Charge upon achievement of PAF equivalent to the NQPAF for cumulative Peak period during the month, and the monthly Off-Peak Period Capacity Charge upon achievement of PAF equivalent to the NQPAF for cumulative Off-Peak period during the month.
(5) Achievement of PAF less than the specified NQPAF in "Peak" or "Off-Peak" periods shall result in pro-rata reduction in recovery of Capacity Charge for the appropriate period.
Provided that if the cumulative peak period PAF achieved during a quarter is more than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is less than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Off-Peak period shall be off-set against</td>
<td>state would be in variance with the "Peak" and "Off-Peak" declared by RLDC of a particular region which is evident from the above.
The peak hours declaration as per the NRLDC website is given below:

Peak Hours Declaration
<table>
<tr><th>Sr. No.</th><th>Month</th><th>Month Duration</th><th>Peak Hours</th><th>BYPL Peak Hrs</th></tr>
<tr><td></td><td></td><td></td><td>As per NRLDC Website</td><td></td></tr>
<tr><td rowspan="2">1</td><td rowspan="2">April</td><td rowspan="2">01-04-2018 to 30-04-2018</td><td>06.30 to 07:30</td><td>12 hrs to 18 hrs</td></tr>
<tr><td>18:30 to 20:30</td><td>23 hrs to 24 hrs</td></tr>
<tr><td>2</td><td>May</td><td>01-05-2018 to 31-05-2018</td><td>18:30 to 21:30</td><td>12hrs to 18 hrs
23 hrs to 24 hrs</td></tr>
</table>
</td>
<td></td></tr>
</table>

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>the notional gain on account of over-achievement in Peak period, subject to the ceiling of full recovery of Capacity Charge for Off-Peak period;
Provided further that if the cumulative peak period PAF achieved during the quarter is less than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is more than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Peak period shall not be off-set against the notional gain on account of over-achievement in Off-Peak period;
Provided also that carry forward of under-recovery of Capacity Charge shall not be allowed for recovery from one quarter to the subsequent quarter.
(6) The Plant Availability Factor achieved for a Day (PAFD), Plant Availability Factor achieved for a Month (PAFM) and Plant Availability Factor achieved for a Quarter (PAFQ) shall be computed in accordance with the following formula:

N
PAFD or PAFM or PAFQ = 10000 x Σ DCi / { N x IC x (100 - AUX) } %</td>
<td>
<table>
<tr><td>3</td><td>June</td><td>01-06-2018 to 30-06-2018</td><td>19:00 to 22:00</td><td>15hrs to 18hrs & 2330hrs to 00hrs</td></tr>
<tr><td>4</td><td>July</td><td>01-07-2018 to 31-07-2018</td><td>19:00 to 22:00</td><td>15.30 hrs to 18hrs & 23.30hrs to 00hrs</td></tr>
<tr><td>5</td><td>Aug ust</td><td>01-08-2018 to 31-08-2018</td><td>19:00 to 22:00</td><td>15.30 hrs to 18hrs & 22.30hrs to 23.30hrs</td></tr>
<tr><td>6</td><td>Sep</td><td>01-09-2018 to 30-09-2018</td><td>19:00 to 22:00</td><td>15.15 hrs to 18hrs & 23.00hrs to 24hrs</td></tr>
<tr><td rowspan="3">7</td><td rowspan="3">Oct</td><td>01-10-2018 to 26-10-2018</td><td>18:30 to 21:30</td><td rowspan="3">11 hrs to 19hrs</td></tr>
<tr><td rowspan="2">27-10-2018 to 30-10-2018</td><td>06:30 to 07:30</td></tr>
<tr><td>18:00 to 20:00</td></tr>
<tr><td>8</td><td>Nov</td><td>01-11-2018 to 30-</td><td>06:30 to 07:30</td><td>11 hrs to 19hrs</td></tr>
</table>
</td>
<td></td></tr>
</table>

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>i=1
Where,
AUX = Normative auxiliary energy consumption in percentage.
DCi = Average declared capacity (in ex-bus MW), for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.
IC = Installed Capacity (in MW) of the generating station
N = Number of days during the period or number of hours during the peak or off-peak periods of the day, as the case may be.
Note: DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken.
(7) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise / kWh for ex-bus scheduled energy during Peak period and @ 50 paise / kWh for ex-bus scheduled energy during Off-Peak period corresponding to scheduled generation in</td><td><table>
<tr><td></td><td></td><td>11-2018</td><td>18:00 to 20:00</td><td></td></tr>
<tr><td rowspan="2">9</td><td rowspan="2">Dec</td><td rowspan="2">01-12-2018 to 31-01-2018</td><td>06:00 to 07:30</td><td rowspan="2">11 hrs to 19hrs</td></tr>
<tr><td>17:45 to 19:15</td></tr>
</table>
Hence, the aforesaid anomaly may be considered while framing the regulations.</td><td></td></tr>
</table>

Draft Regulations	Comments/Rationale	Proposed Regulations
excess of ex-bus energy corresponding to Normative Quarterly Plant Load Factor (NQPLF) as specified in Regulation 59 (B) of these regulations.		
52. Computation and Payment of Energy Charge for Thermal Generating Stations: (1) The energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable), and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel and limestone price adjustment). Total Energy charge payable to the generating company for a month shall be: Energy Charges = (Energy charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh} (2) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formulae: **(a) For coal based and lignite fired stations:**	**Draft Regulation 52:**Variable charges not only depend on fuel cost but also quality and quantity of fuel supplied. Hence, GCV (As billed), quantity (As billed) and cost of fuel (As billed) are also the factor effecting Variable Charges and should also be considered for computation of variable cost 1)As per the CAG report as well as CEA there would be minor loss of GCV in as billed to as received to as fired value: Para 5.2 of CAG report : *"5.2 Reduction in heat value (GCV) of coal……It was observed that GCV of coal progressively decreased from the 'as billed' stage to the 'as fired' stage, though as per CEA, the three GCV values, i.e., GCV 'as billed', 'as received' and 'as fired' should be approximately same barring minor losses due to storage……"* Therefore, there must be a minor difference between as loaded and as received GCV values.	(a) ***"Method for measurement of GCV":*** Method for measuring GCV should be on "Air-Dry basis'' for procurement of coal both from domestic and international suppliers. (b) ***"GCV as billed":***Means the GCV of coal as determined for billing purpose as per which the generator pays to the coal supplier. GCV of Coal or lignite as measured at Coal mine, mined from any seam or section of a seam in the Suppliers' collieries from which Coal is produced and supplied to Generating Companies. Provided that measurement of coal or lignite shall be carried out through Third Party sampling to be appointed by the generating companies in accordance with guidelines, if any, issued by Central Government. Provided that Third Party Sampling

Draft Regulations	Comments/Rationale	Proposed Regulations
ECR = {(SHR – SFC x CVSF) x LPPF / (CVPF + SFC x LPSFi + LC x LPL} x 100 / (100 – AUX) **(b) For gas and liquid fuel based stations** ECR = SHR x LPPF x 100 **/** {(CVPF) x (100 – AUX)} Where, AUX =Normative auxiliary energy consumption in percentage. CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations less 85 Kcal/Kg on account of variation during storage at generating station; (b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations. (c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio. CVSF = Calorific value of secondary fuel, in kCal per ml. ECR = Energy charge rate, in Rupees per kWh sent out. SHR = Gross station heat rate, in kCal per kWh.	2) CEA also prescribed loss of GCV in its Recommendation on operational norms of Thermal Power stations tariff Period 2014-2019 as under; *"…..Para 13.4 It may be pertinent to mention that the **billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as "as received GCV").** Considering the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and as received GCV; however, difference between the as received GCV vis-à-vis "as fired GCV" would be very marginal and would be solely on account of marginal loss of heat during the coal storage…* *3)*Further the MoP has proposed 3rd party sampling. However the Genco's need to be directed to share the test reports of the coal as submitted by the 3rd part agencies to the beneficiaries as well as publish the same on their website. The 3rd party sampling procedure also need to involve the representatives of the beneficiaries to verify the independence and correctness of 3rd party sampling. 4. The FSA with the coal companies provide for the delivery point to the Generator at the mine end. Hence once the property in goods passes to the Generator, it is the Generator	agencies shall not have vested interest in Coal Suppliers/generator

Draft Regulations	Comments/Rationale	Proposed Regulations
LC = Normative limestone consumption in kg per kWh. LPL = Weighted average landed price of limestone in Rupees per kg. LPPF = Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic metre, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed price of primary fuel shall be arrived in proportion to blending ratio) SFC = Normative Specific fuel oil consumption, in ml per kWh. LPSFi = Weighted Average Landed Price of Secondary Fuel in Rs./ml during the month Provided that energy charge rate for a gas or liquid fuel based station shall be adjusted for open cycle operation based on certification of Member Secretary of respective Regional Power Committee for the open cycle operation during the month. (3) In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power	which is liable to account for any drop in GCV thereafter, Hence the GCV as recorded at the mine end minus the existing normative transportation losses must be considered for billing to the beneficiaries. 5. Further the normative loss as per CEA report is of 80 Kcal as prescribed for 30 days storage kept as inventory in the plant. Similarly if the time taken for loading and transportation from the colliery to the plant takes 10 days time another about 25 Kcal normative loss in GCV can be added. Therefore is the billed GCV is 5500 Kcal then the GCV to be used for computation of energy charges to be considered as 5395 (5500-80-25) Kcal	

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purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station: Provided that in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement: Provided further that the weighted average price of use of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (7) of this Regulation. Provided also that where the energy charge rate based on weighted average price of use of fuel including alternative source of fuel exceeds 30% of base energy charge rate as approved by the Commission for that year or energy charge rate based on weighted average price of use of fuel including alternative sources of fuel exceeds 20% of energy charge rate based on based on weighted average fuel price for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made not later than three days in		

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advance. (4) Where the biomass fuel is used for blending with coal, the landed price of biomass fuel shall be worked out based on normative consumption as specified in these regulations or actual consumption, whichever is lower, and landed price discovered at the receiving end of the generating station, inclusive of taxes and duties as applicable; (5) The Commission through the specific tariff orders to be issued for each generating station shall approve the energy charge rate at the start of the tariff period. The energy charge so approved shall be the base energy charge rate at the start of the tariff period. The base energy charge rate for subsequent years shall be the energy charge computed after escalating the base energy charge rate approved at the start of the tariff period by escalation rates for payment purposes as notified by the Commission from time to time for under competitive bidding guidelines. (6) The tariff structure as provided in this Regulation 51 and Regulation 52 of these regulation may be adopted by the Department of		

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Atomic Energy, Government of India for the nuclear generating stations by specifying annual fixed cost (AFC), normative quarterly plant availability factor (NQPAF), installed capacity (IC), normative auxiliary power consumption (AUX) and energy charge rate (ECR) for such stations.		
53. Declaration of Availability and Dispatch in case of thermal generating station: The generating company shall declare day ahead availability or any revision thereof in respect of generating station for each fuel source which may be differentiated in terms of their price and calorific value and the beneficiaries shall have an option to schedule the power based on their merit order dispatch.	**Draft Regulation 53** requires the that the day ahead availability or any revision thereof be declared for each generating station for each fuel source. Further, the Regulation gives option to the beneficiaries to schedule power on their merit order dispatch. In this regard it is submitted that the said draft Regulation ought to be amended to include the parameters for a minimum proportion of RLNG as fuel to declare availability, since: - (a) Most of the generators are declaring the availability on the basis of the SPOT gas as fuel. SPOT is an expensive fuel resulting in higher costs leading to additional tariff burden on the consumers. (b) The same is also imperative since with the use of SPOT gas, these gas based plants do not come under the Merit Order of the Discoms. (c) Hence, even if the Discoms want to purchase power from these gas based Plants, the same will lead to merit order violation on one hand and on the other hand would lead	Hon'ble Commission must cap the Genco's ability to rely on SPOT gas to declare availability.Ceiling value in terms of percentage of Installed Capacity for generators must be defined. Such as Generators may be allowed to declare DC during peak hrs/peak season

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	to high fixed costs even if Discoms do not purchase Actual power. Therefore, in view of the above it is requested that the availability declared by a gas based plant should not be on the basis spot gas and there should be a parameter that a generating company has to have a proportion of RLNG gas to declare availability since.	
54. Computation and Payment of Capacity charge and Energy Charge for Hydro Generating Stations: (1) The fixed cost of a hydro generating station shall be computed on annual basis, based on norms specified under these regulations, and shall be recovered on monthly basis under capacity charge (inclusive of incentive) and energy charge, which shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., in the capacity excluding the free power to the home State: Provided that during the period between the date of commercial operation of the first unit of the		

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generating station and the date of commercial operation of the generating station, the annual fixed cost shall provisionally be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge and energy charge payment during such period. (2) The capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month shall be: AFC x 0.5 x NDM / NDY x (PAFM / NAPAF) (in Rupees) Where, AFC = Annual fixed cost specified for the year, in Rupees NAPAF = Normative plant availability factor in percentage NDM = Number of days in the month NDY = Number of days in the year PAFM = Plant availability factor achieved during the month, in percentage		
(3) The PAFM shall be computed in accordance with the following formula:	**54(3)**: the definition of DCi should be modified to "Declared capacity (in ex-bus MW) for the ith day of the month which the station can deliver for ~~at least~~ minimum of three (3) hours, as	

Draft Regulations	Comments/Rationale	Proposed Regulations
$$PAFM = 10000 \times \sum_{i=1}^{N} DC_i \,/\, \{ N \times IC \times (100 - AUX) \} \%$$ Where AUX = Normative auxiliary energy consumption in percentage DCi = Declared capacity (in ex-bus MW) for the ith day of the month which the station can deliver for at least three (3) hours, as certified by the nodal load dispatch centre after the day is over. IC = Installed capacity (in MW) of the complete generating station N = Number of days in the month 4) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary, excluding free energy, if any, during the calendar month, on ex power plant basis, at the computed energy charge rate. Total Energy charge payable to the generating company for a month shall be: Energy Charges = (Energy charge rate in Rs. /	certified by the nodal load dispatch centre after the day is over. Right now NRLDC is taking average of peak hours (3 hours). It is requested not to consider any notional number by computing the average DC for peak hours for computing the DC for the full day instead we request you to consider the minimum DC value in peak hours which actually the plant has demonstrated for these 3 peak hours/ average DC of operational hours allowed by NRLDC may be considered. The same has also been communicated and deliberated at RPC forum and has been of no avail.	

Draft Regulations	Comments/Rationale	Proposed Regulations
kWh) x {Scheduled energy (ex-bus) for the month in kWh} x (100 – FEHS) / 100 (5) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis, for a hydro generating station, shall be determined up to three decimal places based on the following formula, subject to the provisions of clause (7) of this Regulation: ECR = AFC x 0.5 x 10 / { DE x (100 – AUX) x (100 – FEHS)} Where, DE = Annual design energy specified for the hydro generating station, in MWh, subject to the provision in clause (6) below. FEHS = Free energy for home State, in per cent, as mentioned in Regulation 65 of these regulations. (6) In case the actual total energy generated by a hydro generating station during a year is less than the design energy for reasons beyond the control of the generating station, the following treatment shall be applied on a rolling basis on an application filed by the generating company: (7) In case the energy shortfall occurs within ten years from the date of commercial operation of a generating station, the ECR for the year following		

Draft Regulations	Comments/Rationale	Proposed Regulations
the year of energy shortfall shall be computed based on the formula specified in clause (5) with the modification that the DE for the year shall be considered as equal to the actual energy generated during the year of the shortfall, till the energy charge shortfall of the previous year has been made up, after which normal ECR shall be applicable: Provided that in case actual generation form a hydro generating station is less than the design energy for a continuous period of 4 years on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station. (8) In case the energy shortfall occurs after ten years from the date of commercial operation of a generating station, the following shall apply. **Explanation:** Suppose the specified annual design energy for the station is DE MWh, and the actual energy generated during the concerned (first) and the following (second) financial years is A1 and A2 MWh respectively, A1 being less than DE. Then, the design energy to be considered in the formula in clause (5) of this Regulation for		

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calculating the ECR for the third financial year shall be moderated as (A1 + A2 – DE) MWh, subject to a maximum of DE MWh and a minimum of A1 MWh. (9) Actual energy generated (e.g. A1, A2) shall be arrived at by multiplying the net metered energy sent out from the station by 100 / (100 – AUX). (10) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation exceeds ninety paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the Energy charge for the energy in excess of the above shall be billed at ninety paise per kWh only: Provided that in a year following a year in which total energy generated was less than the design energy for reasons beyond the control of the generating company, the energy charge rate shall be reduced to ninety paise per kWh after the energy charge shortfall of the previous year has been made up. (11) In case of the hydro generating stations located in the State of Jammu and Kashmir, any expenditure incurred for payment of water usage		

Draft Regulations	Comments/Rationale	Proposed Regulations
charges to the State Water Resources Development Authority, Jammu under Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010 shall be payable by the beneficiaries as additional energy charge in proportion of the supply of power from the generating stations on month to month basis: Provided that the provisions of this clause shall be subject to the decision of the Hon'ble High Court of Jammu & Kashmir in OWP No. 604/2011 and shall stand modified in accordance with the decision of the High Court.		
55. Pumped Storage Hydro Generating Stations: (1) The fixed cost of a pumped storage hydro generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis as capacity charge. The capacity charge shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., the capacity excluding the free power to the home State: Provided that during the period between the date	**Draft Regulation 55:** The COD's of such plants usually takes time on account of several issues (esp. R&R). The same has been the case with Tehri PSP's COD, which has been considerably delayed leading to significant cost over-run to the tune of 165% and this would invariably lead to a tariff shock for the consumer of individual beneficiaries. Hence, we propose Hon'ble Commission to consider these plants to be used for Grid support stations and bifurcate the costs and power from these plants by not restricting the same only to the beneficiaries who have signed the PPA. These stations can be ramped up and ramped down quickly and can act as very good balancing support for RE power. We had requested the same to the Hon'ble commission in our	

Draft Regulations	Comments/Rationale	Proposed Regulations
of commercial operation of the first unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge payment during such period. (2) The capacity charge payable to a pumped storage hydro generating station for a calendar month shall be: (AFC x NDM / NDY) (in Rupees), if actual Generation during the month is >= 75 % of the Pumping Energy consumed by the station during the month and {(AFC x NDM / NDY) x (Actual Generation during the month during peak hours/ 75% of the Pumping Energy consumed by the station during the month) (in Rupees)}, if actual Generation during the month is < 75 % of the Pumping Energy consumed by the station during the month. Where, AFC = Annual fixed cost specified for the year, in Rupees	comments on consultation paper for tariff regulation FY 2019-24	

Draft Regulations	Comments/Rationale	Proposed Regulations
NDM = Number of days in the month NDY = Number of days in the year Provided that there would be adjustment at the end of the year based on actual generation and actual pumping energy consumed by the station during the year. (3) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary in excess of the design energy plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir, at a flat rate equal to the average energy charge rate of 20 paise per kWh, excluding free energy, if any, during the calendar month, on ex power plant basis. 4) Energy charge payable to the generating company for a month shall be: = 0.20 x {Scheduled energy (ex-bus) for the month in kWh – (Design Energy for the month (DEm) + 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month)} x (100 – FEHS)/ 100. Where,		

Draft Regulations	Comments/Rationale	Proposed Regulations
DEm = Design energy for the month specified for the hydro generating station, in MWh FEHS = Free energy for home State, in per cent, as mentioned in Regulation 65 of these regulations, if any. Provided that in case the Scheduled energy in a month is less than the Design Energy for the month plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month, then the energy charges payable by the beneficiaries shall be zero. (5) The generating company shall maintain the record of daily inflows of natural water into the upper elevation reservoir and the reservoir levels of upper elevation reservoir and lower elevation reservoir on hourly basis. The generator shall be required to maximize the peak hour supplies with the available water including the natural flow of water. In case it is established that generator is deliberately or otherwise without any valid reason, is not pumping water from lower elevation reservoir to the higher elevation during off-peak period or not generating power to its		

Draft Regulations	Comments/Rationale	Proposed Regulations
potential or wasting natural flow of water, the capacity charges of the day shall not be payable by the beneficiary. For this purpose, outages of the unit(s)/station including planned outages and the forced outages up to 15% in a year shall be construed as the valid reason for not pumping water from lower elevation reservoir to the higher elevation during off-peak period or not generating power using energy of pumped water or natural flow of water: Provided that the total capacity charges recovered during the year shall be adjusted on pro-rata basis in the following manner in the event of total machine outages in a year exceeds 15%: ACC)adj = (ACC) R x (100- ATO)/85 Where, (ACC)adj – Adjusted Annual Capacity Charges (ACC) R – Annual Capacity Charges recovered ATO - Total Outages in percentage for the year including forced and planned outages Provided further that the generating station shall be required to declare its machine availability daily on day ahead basis for all the time blocks of the day in line with the scheduling		

Draft Regulations	Comments/Rationale	Proposed Regulations
procedure of Grid Code. (6) The concerned Load Despatch Centre shall finalise the schedules for the hydro generating stations, in consultation with the beneficiaries, for optimal utilization of all the energy declared to be available, which shall be scheduled for all beneficiaries in proportion to their respective allocations in the generating station.		
Norms of operation for thermal generating station **59.** The norms of operation as given hereunder shall apply to thermal generating stations: **(A) Normative Quarterly Plant Availability Factor (NQPAF)** (a) For all thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 83% Provided that for the purpose of computation of Normative Quarterly Plant Availability Factor, annual scheduled plant maintenance shall not be considered	**Draft Regulation 59(A)(a)**: As evident from the Table No. 45 of the explanatory memorandum which provides actual average PAF for NTPC station for past five years, most of the plants have declared PAF more than 90%. As such there is no need to lower the PAF from 85% (provided in the earlier regulations) to 83%. Moreover, since October, 2018, MoP has allowed import of coal for CPSUs. Thereby, mitigating the risk associated with shortage of coal arising out of limited domestic coal	

Draft Regulations	Comments/Rationale	Proposed Regulations
(b) For following Lignite-fired Thermal generating stations of NLC India Ltd: TPS-I 72% (c) For following Thermal Generating Stations of DVC: Bokaro TPS 75% Chandrapura TPS 75% Durgapur TPS 74% (d) For following Gas based Thermal Generating Stations of NEEPCO: Assam GPS 72% (e) For Lignite fired Generating Stations using	production. Therefore, it is suggested that the NQPAF should be revised to 85% for off-peak and 95% for peak hour. Further, there is a need to mitigate the issue of plant annual maintenance. It is on account of the fact the proviso to Regulation provides that for computation of NQPAF the annual plant maintenance shall not be considered. Commission has to provide for a solution so that the annual maintenance should be done in a phased manner that the same is scheduled and finished in two quarters so as to improve efficiency.	

Draft Regulations	Comments/Rationale	Proposed Regulations
Circulatory Fluidized Bed Combustion (CFBC) Technology and Generating stations based on coal rejects: 1. First Three years from the date of commercial operation – 75% 2. For next year after completion of three years of the date of commercial operation – 80% **(B) Normative Quarterly Plant Load Factor (NQPLF) for Incentive:** (a) For all thermal generating stations, except those covered under clauses (b), (c) - 85% (b) For following Lignite-fired Thermal generating stations of NLC India Ltd : TPS – I 75 % (c) For following Thermal Generating Stations of Damodar Valley Corporation (DVC): Bokaro TPS 80 % Chandrapur TPS 80 %		

<table>
<tr><th>Draft Regulations</th><th>Comments/Rationale</th><th>Proposed Regulations</th></tr>
<tr><td>Durgapur TPS 80 %

(C) Gross Station Heat Rate:
(a) Existing Thermal Generating Station
(i) For existing Coal-based Thermal Generating Stations, other than those covered under clauses (ii) and (iii) below:

<table><tr><th>200/210/250 MW Sets</th><th>500 MW Sets (Sub-critical)</th></tr><tr><td>2,410 kCal/kWh</td><td>2,375 kCal/kWh</td></tr></table>
Note 1
In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.
Note 2
For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.
Note 3</td><td></td><td></td></tr>
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Draft Regulations	Comments/Rationale	Proposed Regulations
The normative gross station heat rate above is exclusive of the compensation specified in Regulation 6.3 B of the Grid Code. The generating company shall, based on unit loading factor, consider the compensation in addition to the normative gross heat rate above. (ii) For following Thermal generating stations of NTPC Ltd: Talcher TPS 2,830 kCal/kWh Tanda TPS 2,750 kCal/kWh (iii) For Thermal Generating Stations of Damodar Valley Corporation (DVC): Bokaro TPS 2,700 kCal/kWh Chandrapura TPS (Unit 1 to 3) 3,000 kCal/kWh Durgapur TPS 2,750 kCal/kWh (iv) For Lignite-fired Thermal Generating Stations: For lignite-fired thermal generating		

Draft Regulations	Comments/Rationale	Proposed Regulations
stations, except for TPS-I and TPS-II (Stage I & II) of NLC India Ltd, the gross station heat rates specified under sub-clause (i) for coal-based thermal generating stations shall be applied with correction, using multiplying factors as given below: (a) For lignite having 50% moisture: 1.10 (b) For lignite having 40% moisture: 1.07 (c) For lignite having 30% moisture: 1.04 For other values of moisture content, multiplying factor shall be pro-rated for moisture content between 30-40% and 40-50% depending upon the rated values of multiplying factor for the respective range given under sub-clauses (a) to (c) above. (v) TPS-I and TPS-II (Stage I & II) of NLC India Ltd: TPS-I : 4,000 kCal/kWh TPS-II : 2,720 kCal/kWh TPS- I (Expansion) :		

Draft Regulations	Comments/Rationale	Proposed Regulations
2,750 kCal/kWh (vi) Open Cycle Gas Turbine/Combined Cycle generating stations: For following existing gas based thermal generating stations: **Name of generating station** — **Combined (kCal/kWh)** Gandhar GPS — 2,040 Kawas GPS — 2,050 Anta GPS — 2,075 Dadri GPS — 2,000 Auraiya GPS — 2,100 Faridabad GPS — 1,975 Kayamkulam GPS — 2,000 Assam GPS — 2,600 Agartala GPS — 2,600 Sugen — 1,760 Ratnagiri — 1,820		
(b) New Thermal Generating Station achieving COD on or after 1.4.2009: (i) For Coal-based and lignite-fired Thermal Generating Stations:	**Draft Regulation 59 (C)(b)(i)** provides that while calculating the operational norms for new thermal generating station achieving COD on or after 01.04.2009 the heat rate of 1.05 shall be considered. It is submitted that there is no reason provided	**(b) New Thermal Generating Station achieving COD on or after 1.4.2009:** (i) For Coal-based and lignite-fired Thermal Generating Stations: ~~1.05~~ 1.045 X Design Heat Rate (kCal/kWh)

Draft Regulations	Comments/Rationale	Proposed Regulations
1.05 X Design Heat Rate (kCal/kWh) Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure. Provided that the design heat rate shall not exceed the following maximum design unit heat rates depending upon the pressure and temperature ratings of the units: Pressure Rating (Kg/cm2) 150 SHT/RHT (0C) 535/535 Type of BFP Electrical Driven Max Turbine Heat Rate (kCal/kWh) 1955 Min. Boiler Efficiency Sub-Bituminous Indian Coal 0.86 Bituminous Imported Coal 0.89 Sub-Bituminous Indian Coal 2273 Bituminous Imported Coal 2197 Pressure Rating 247 247	in the explanatory memorandum as to why the multiplier for design heat rate is increased from 1.045 to 1.05 from the Tariff Regulations 2014-2019. It is submitted that the Hon'ble Commission should consider reducing the same to original, as: (a) Hon'ble Commission in the Draft Regulations has only proposed for Capacity charges under Regulation 15 and not variable charges. () There are no reasons provided for not providing a two-part tariff for Transmission. Therefore, in view of the above, the Hon'ble Commission should consider reducing the heat rate from 1.05 to 1.045. The Hon'ble Commission should determine two part tariff for transmission companies since: a. Increase would provide a buffer for Gencos which invariably would reduce the motivating of Gencos to improve their efficiency. b. It may also be noted that any loss on account of GHR would be reimbursed to the Gencos via compensation mechanism. Hence, previous equation for computation of GHR may be	

Draft Regulations			Comments/Rationale		Proposed Regulations
(Kg/cm2)			retained.		
SHT/RHT (0C)	537/565	565/593	593/593	600/ 600	
Type of BFP	Turbine Driven	Turbine Driven	Turbine Driven	Turbine Driven	
Max Turbine Heat Rate (kCal/kWh)	1900	1850	1810	1800	
Min. Boiler Efficiency					
Sub-Bituminous Indian Coal	0.86	0.86	0.865	0.865	
Bituminous Imported Coal	0.89	0.89	0.895	0.895	
Sub-Bituminous Indian Coal	2222	2151	2105	2081	
Bituminous Imported Coal	2135	2078	2034	2022	
Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken: Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using					

Draft Regulations	Comments/Rationale	Proposed Regulations
guaranteed turbine cycle heat rate and boiler efficiency: Provided also that where the boiler efficiency is below 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% respectively for Sub-bituminous Indian coal and bituminous imported coal for computation of station heat rate: Provided also that maximum turbine cycle heat rate shall be adjusted for type of dry cooling system: Provided also that if one or more generating units were declared under commercial operation prior to 1.4.2019, the heat rate norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2019 shall be lower of the heat rate norms arrived at by above methodology and the norms as per the sub-clause (C)(a)(i) of this Regulation: Provided also that in case of lignite-fired generating stations (including stations based on CFBC technology), maximum design heat rates shall be increased using factor for moisture content given in sub-clause (C)(a)(iv) of this		

Draft Regulations	Comments/Rationale	Proposed Regulations
Regulation: Provided also that for Generating stations based on coal rejects, the Commission will approve the Design Heat Rate on case to case basis. **Note:** In respect of generating units where the boiler feed pumps are electrically operated, the maximum design unit heat rate shall be 40 kCal/kWh lower than the maximum design unit heat rate specified above with turbine driven Boiler Feed Pump. **(c) For Gas-based / Liquid-based thermal generating unit(s)/ block(s) having COD on or after 1.4.2009:** For Natural Gas = 1.050 X Design Heat Rate of the unit/block (kCal/kWh) For RLNG =1.071 X Design Heat Rate of the unit/block for Liquid Fuel (kCal/kWh) Where the Design Heat Rate of a unit shall mean the guaranteed heat rate for a unit at 100% MCR and at site ambient conditions; and the Design Heat Rate of a block shall mean the guaranteed heat rate for a block at 100% MCR, site ambient conditions, zero percent make up, design cooling water temperature/back pressure. **(D) Secondary fuel oil consumption:**		

Draft Regulations	Comments/Rationale	Proposed Regulations
(a) For Coal-based generating stations other than at (c) below: 0.50 ml/kWh (b) (i) For Lignite-fired generating stations except TPS-I : 1.0 ml/kWh (ii) For TPS-I : 1.5 ml/kWh (c) For Coal-based generating stations of DVC: Bokaro TPS 1.5 ml/kWh Chandrapur TPS 1.5 ml/kWh Durgapur TPS 2.4 ml/kWh		
d) For Generating Stations based on Coal Rejects : 2.0 ml/kWh **(E) Auxiliary Energy Consumption :** (a) For Coal-based generating stations except at (b) below: S. No. **Generating Station** **With Natu without co** (i) 200 MW series 8.50% (ii) 300/330/350/500 MW series		

Draft Regulations	Comments/Rationale	Proposed Regulations
Steam driven boiler feed pumps 5.75% Electrically driven boiler feed pumps 8.00% (iii) 600 MW and above Steam driven boiler feed pumps 5.75% Electrically driven boiler feed pumps 8.00% Provided that for thermal generating stations with induced draft cooling towers and where tube type coal mill is used, the norms shall be further increased by 0.5% and 0.8% respectively: Provided further that Additional Auxiliary Energy Consumption as follows may be allowed for plants with Dry Cooling Systems: **Cooling System** **(% ger** ; air cooled condensers with mechanical draft 1.0 ng system employing jet condensers with 0.5 ery turbine and natural draft tower (b) For Other Coal-based generating stations:		

Draft Regulations	Comments/Rationale	Proposed Regulations
(i) Talcher Thermal Power Station 10.50 % (ii) Tanda Thermal Power Station 11.50 % (iii) Bokaro Thermal Power Station 10.25 % (iv) Chandrapur Thermal Power Station 9.50% (v) Durgapur Thermal Power Station 10.50 % (c) For Gas Turbine /Combined Cycle generating stations: (i) Combined Cycle : 2.75% (ii) Open Cycle : 1.00% (d) For Lignite-fired thermal generating stations: (i) For all generating stations with 200 MW sets and above: The auxiliary energy consumption norms shall be 0.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above. Provided that for the lignite fired stations using CFBC technology, the auxiliary energy		

Draft Regulations	Comments/Rationale	Proposed Regulations
consumption norms shall be 1.5 percentage point more than the auxiliary energy consumption norms of coal-based generating stations at (E) (a) above. (ii) For Barsingsar Generating station of NLC using CFBC technology: 12.50% (iii) For TPS-I, TPS-I (Expansion) and TPS-II Stage-I&II of NLC India Ltd.: TPS-I 12.00 % TPS-II 10.00 % TPS-I (Expansion) 8.50% (iv) For Lime stone consumption for lignite-based generating station using CFBC technology: Barsingsar : 0.056 kg/kWh TPS-II (Expansion) : 0.046 kg/kWh (e) For Generating Stations based on coal rejects: 10%		
60. Norms of operation for hydro generating stations: (1) The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:		

Draft Regulations	Comments/Rationale	Proposed Regulations
(a) Storage and Pondage type plants with head variation between Full Reservoir Level (FRL) and Minimum Draw Down Level (MDDL) of up to 8%, and where plant availability is not affected by silt : 90% (b) In case of storage and pondage type plants with head variation between full reservoir level and minimum draw down level is more than 8% and when plant availability is not affected by silt, the month wise peaking capability as provided by the project authorities in the DPR (approved by CEA or the State Government) shall form basis of fixation of NAPAF. (c) Pondage type plants where plant availability is significantly affected by silt: 85%. Run-of-river type plants: NAPAF to be determined plant-wise, based on 10-day design energy data, moderated by past experience where available/relevant. (2) A further allowance may be made by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations.		

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(3) A further allowance of 5% may be allowed for difficulties in North East Region.

(4) Based on the above, the Normative annual plant availability factor (NAPAF) of the hydro generating stations already in operation shall be as follows :-

<table>
<tr><th>ıtion</th><th>Type of Plant</th><th>Plant Capacity No. of Units x MW</th><th>NAPF (%)</th></tr>
<tr><td>IDC</td><td></td><td></td><td></td></tr>
<tr><td>IDC Stage</td><td>Storage</td><td>4x250</td><td>80</td></tr>
<tr><td>IEP</td><td>Storage</td><td>4x100</td><td>68</td></tr>
<tr><td>IPC</td><td></td><td></td><td></td></tr>
<tr><td>irasul</td><td>Pondage</td><td>3x60</td><td>91</td></tr>
<tr><td>ktak</td><td>Pondage</td><td>3x35</td><td>88</td></tr>
<tr><td>lal</td><td>ROR</td><td>5x115</td><td>64</td></tr>
<tr><td>nakpur</td><td>ROR</td><td>3x31.4</td><td>59</td></tr>
<tr><td>ıamera-I</td><td>Pondage</td><td>3x180</td><td>93</td></tr>
<tr><td>i I</td><td>ROR</td><td>4x120</td><td>74</td></tr>
<tr><td>ngit</td><td>Pondage</td><td>3x20</td><td>92</td></tr>
<tr><td>ıamera-II</td><td>Pondage</td><td>3x100</td><td>93</td></tr>
<tr><td>ıauliganga</td><td>Pondage</td><td>4x70</td><td>78</td></tr>
</table>
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<td>
For Parbati-3 NAPFM should be considered as 68% as per CERC Order dated 25.06.2014 in Petition 228/GT/2013:It is proposed that the NAPAF for hydro plant shall be considered on actual average PAF for last five years excluding Dhauliganga & Parbati-III. For Dhauliganga for the year 2013-14 is abnormally low therefore, it is proposed that for the said plant current PAF should prevail.
However,for Parbati-3, this Hon'ble Commission has,by order dated 25.06.2014 in petition 228/GT/2013, worked out NAPAF based on peaking hours till the commissioning of upstream Parbati-II plant. Hence it is very clear that the plant can achieve PAFM of 68% based on approved DE and peaking hours. The relevant part of the order dated 25.06.2014 is reproduced herein:

"Based on the '10-daily Design Energy' approved by CEA along with the provision of providing 3 hours of daily peaking (in two slots of morning & evening each for 1.5 hours), the NAPAF of 68% has been worked out and allowed till the commissioning of upstream Parbati-II HEP as against the claim of 31% by the petitioner based
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Draft Regulations	Comments/Rationale	Proposed Regulations
Dulhasti Pondage 3x130 91 Teesta-V Pondage 3x170 87 Sewa-II Pondage 3x40 89 TLDP III Pondage 4x33 77 Chamera III Pondage 3x77 87 Chutak ROR 4x11 48 Nimmo Bazgo Pondage 3x15 70 Uri II Pondage 4x60 70 Parbati III Pondage 4x130 43 **NHDC** Indira Sagar Storage 8x125 87 Omkareshwar Pondage 8x65 93 **NEEPCO** Kopili I Storage 4x50 69 Khandong Storage 2x25 67 Kopili II Storage 1x25 69 Doyang Storage 3x25 70 Ranganadi Pondage 3x135 88 **NTPC** Koldam Storage 4x200 90 **SJVNL** Nathpa Jhakri Storage 6x250 90	*on ROR operation. The computation of NAPAF is enclosed as Annexure-I to this order."* Hence, this Hon'ble Commission may consider the NAPAF, approved via previous tariff orders, of these plants in the present Draft Regulations.	

Draft Regulations	Comments/Rationale	Proposed Regulations
DVC Panchet Storage 2x40 80 Tilaya Storage 2x2 80 Maithon Storage 3x20 80 5) In case of Pumped storage hydro generating stations, the quantum of electricity required for pumping water from down-stream reservoir to up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses etc. up to the bus bar of the generating station. In return, beneficiaries shall be entitled to equivalent energy of 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir from the generating station during peak hours and the generating station shall be under obligation to supply such quantum of electricity during peak hours: Provided that in the event of the beneficiaries failing to supply the desired level of energy during off-peak hours, there will be pro-rata reduction in their energy entitlement from the station during peak hours: Provided further that the beneficiaries may assign		

Draft Regulations	Comments/Rationale	Proposed Regulations
or surrender their share of capacity in the generating station, in part or in full, or the capacity may be reallocated by the Central Government, and in that event, the owner or assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled. **(6)** Auxiliary Energy Consumption (AEC): **Station** **AEC** **Capacity above 200 MW** **Installed Capacity upto** Excitation 0.7 % 0.7% 1.0 % 1.2% **ound** Excitation 0.9 % 0.9% 1.2 % 1.3%		
69. Late payment surcharge: In case the payment of any bill for charges payable under these	**Draft Regulation 69** provides that the LPSC would be of 1.25% per month. It is submitted that the Hon'ble Commission	**69. Late payment surcharge:** In case the payment of any bill for charges payable

Draft Regulations	Comments/Rationale	Proposed Regulations
regulations is delayed by a beneficiary or long term transmission customers as the case may be, beyond a period of 45 days from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company or the transmission licensee, as the case may be.	should consider amending the Regulation, as: (a) LPSC shall be in line with the actual MCLR. (b) Rate of late payment surcharge needs to be reviewed. As existing interest rates of banks have reduced drastically. (c) Further it is suggested that LPSC ought to have two components. 1. Being the actual cost of borrowings (subject to a cap of SBI MCLR) of Gencos/Transcos and; 2. Margin of 1% as Penalty The above is also in line with various Banks ruleswhere a separate Penal provisions are clearly defined as a separate head. Thus, it is requested that the Hon'ble Commission to consider aligning LPSC in line with the actual borrowing rateof the Gencowith penal provision of 1%.	under these regulations is delayed by a beneficiary or long term transmission customers as the case may be, beyond a period of 45 days from the date of billing, a late payment surcharge at the rate of actual borrowing of Genco/Transco (subject to capping of 15%) plus 1% at simple interest shall be levied by the generating company or the transmission licensee, as the case may be.
70. Sharing of gains due to variation in norms: (1) The generating company or the transmission licensee shall workout gains based on the actual performance of applicable Controllable parameters as under:		

Draft Regulations	Comments/Rationale	Proposed Regulations
i) Station Heat Rate; ii) Secondary Fuel Oil Consumption; iii) Auxiliary Energy Consumption; and iv) Re-financing, Re-structuring of Loans or otherwise change in Interest Rate of Loan. (2) The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between generating company or transmission licensee and the beneficiaries or long term transmission customers, as the case may be, on monthly basis with annual reconciliation. The financial gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters as shown in Clause 1 of this Regulation shall be shared in the ratio of 50:50 between the generating stations and beneficiaries. Net Gain = (ECRN– ECRA) x Scheduled		

Draft Regulations	Comments/Rationale	Proposed Regulations
Generation Where, ECRN = Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption. ECRA = Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption for the month. Provided that in case of hydro generating stations, the net gain on account of Actual Auxiliary Energy Consumption being less than the Normative Auxiliary Energy Consumption, shall be computed as per following formulae provided the saleable scheduled generation is more than the saleable design energy and shall be shared in the ratio of 50:50 between generating station and beneficiaries.: (i) When saleable scheduled generation is more than saleable design energy on the basis of normative auxiliary consumption and less than or equal to saleable design energy on the basis of	Draft Regulation 70(2)(i): While computing the actual ECR for sharing of gain of controllable parameters, SHR, AUX and SFC shall be capped at normative values as ceiling norms to avoid dilution of gains. Reliance is also placed on the judgment of the Hon'ble Supreme Court in C.A. No. 879 of 2019 dated 21.01.2019 wherein it was held that: *"25. As part of the process, the delegate has to bear in mind the interests of diverse stake holders including consumers and producers. The process of framing tariffs is of equal significance, for it is through the procedural framework that norms of consistency, transparency and predictability can be enforced*. ***Competition, efficiency and quality of supply are key components of the policy framework in designing tariffs***. *Clause 5.3(f) of the tariff policy speaks of the need to evolve performance norms which incorporate incentives and disincentives and provide an appropriate arrangement that fosters the sharing of gains of efficiency in operations with consumers.*	

Draft Regulations	Comments/Rationale	Proposed Regulations
actual auxiliary consumption: Net gain (Million Rupees) = [(Saleable Scheduled generation in MUs) – (Saleable Design energy on the basis of normative auxiliary consumption in MUs)] x 0.90 (ii) When saleable scheduled generation is more than saleable design energy on the basis of actual auxiliary consumption: Net gain (Million Rupees)= {Saleable Scheduled generation in MUs- [(Saleable Scheduled Generation in MUs x (100-normative AEC in %)/(100- actual AEC in %)]}x 0.90 devotailed	*Operating parameters in tariffs are required to be pegged only on a "normative level" and not at the "lower of normative and actuals", save and except in those cases referred to in paragraph 5.3(h)(2).* ***Paragraph 5.3(h)(2) deals with those cases where operations have been much below the norm for several previous years****. In those cases, the initial starting point in determining the revenue requirement and the trajectories are fixed at a relaxed level and not at desired levels. Under clause 5.3(f), the operating norms must fulfil several parameters.* ***They must be (i) efficient; (ii) relatable to past performance; (iii) capable of achievement; and must progressively reflect increased efficiencies****. They may also take into consideration latest technological advances, fuel, vintage of equipment, nature of operations, level of service to be provided to consumers, among other factors.* ***Continuous and proven inefficiency has to be controlled and penalised.*** *The operating norms must be designed to promote efficiency and to ensure that the gains which accrue on account of efficient operations are shared with the consumers of electricity.* ***The operating norms will, therefore, have due regard to the performance in the past as well as capacities for future achievement. These must be dovetailed with all relevant considerations, bearing on the requirements of the policy****.* In view of the aforesaid judgment, this Hon'ble Commission	

Draft Regulations	Comments/Rationale	Proposed Regulations
	while providing operational parameters should consider the performance of the plants in the past as well as capacities for future achievement. Accordingly, promote efficiencies of the generating plant and also penalise the generating plant for its inefficiencies, so as to reduce the burden on tariff by not passing the inefficiencies of generating plants.	
72. Sharing of Non-Tariff Income: The non-tariff income in case of generating station and transmission system on account of following shall be shared in the ratio of 50:50 with the beneficiaries and the long term customer on annual basis: a) Income from rent of land or buildings; b) Income from sale of scrap; c) Income from statutory investments; d) Interest on advances to suppliers or contractors; e) Rental from staff quarters;	**Draft Regulation 72:** There no question of sharing of non-tariff income with the beneficiaries. The entire quantum of non-tariff income is required to be deducted from ARR of the generator and the transmission licensee, as is done in the case of the distribution licensee.	

Draft Regulations	Comments/Rationale	Proposed Regulations
f) Rental from contractors; g) Income from advertisements; h) Interest on investments and bank balances Provided that the interest or dividend earned from investments made out of Return on Equity corresponding to the regulated business of the Generating Company shall not be included in Non-Tariff Income.		
77. Deferred Tax liability with respect to previous tariff period: Deferred tax liabilities for the period upto 31st March, 2009 whenever they materialise shall be recoverable directly by the generating companies or transmission licensees from the then beneficiaries or long term transmission customers/DICs, as the case may be. Deferred tax liabilities for the past periods, if any shall not be recoverable from the beneficiaries or the long term transmission customers/DICs, as the case may be.	In the prevailing scenario, Genco's are providing CA certificate which are brief in nature. However, despite our repeated requests the detailed breakup of the basis computation of deferred tax liability amount with respect to previous tariff period has not been provided. We would request Hon'ble Commission to provide for a provision which mandates generator to provide the following information: • Block wise and Plant wise deferred tax liabilities accumulated as on 31.3.2009 along with asset wise backup details. • Year on year Block wise and Plant wise depreciation as	

Draft Regulations	Comments/Rationale	Proposed Regulations
	per companies Act and Income Tax act in respect of assets existing as on 31.03.2009 and deferred tax liability materialized since 31.03.2009 along with backup details. • Comparison of computed depreciation as per companies Act and IT act from the COD of the plant to 31.03.2018. The existing regulation provides for recovery of deferred tax liability with respect to previous tariff period, whereas Gencos are grossing up the deferred tax liability amount with tax rates. Hence, it is requested that this Hon'ble Commission may clarify the aforesaid position and provide for a provision which requires the generator to mandatorily provide the aforesaid information for deferred Tax liability.	