Central Electricity Regulatory Commission

New Delhi

Explanatory Memorandum

on

Draft Central Electricity Regulatory Commission

(Terms and Conditions of Tariff) Regulations, 2019

December, 2018

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1 Introduction

1.1 Background

1.1.1 The Central Electricity Regulatory Commission (hereinafter referred to as the 'CERC' or 'the Commission') was constituted under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 to discharge the duties and perform the functions specified under Section 13 of the ERC Act, 1998. Upon enactment of the Electricity Act, 2003 (hereinafter referred to as 'the Act'), the CERC was deemed to be constituted under the Act.

1.1.2 The Commission has been vested with the functions of regulating the tariff of the generating companies owned or controlled by the Central Government; regulating the tariff of generating companies having a composite scheme for generation and sale of electricity in more than one State; to regulate inter-state transmission of electricity and to determine the tariff for inter-State transmission in electricity under Section 79(1) of the Act, among other functions.

1.1.3 The Act provides a wider role to the Commission which includes promoting competition, efficiency and economy in bulk power markets, improve the quality of supply, promote investments and advise government on removal of institutional barriers to allow for the bridging of the demand supply gap and thus foster the interests of consumers.

1.1.4 Section 61 of the Act provides the guiding principles for the Central Commission while specifying the terms and conditions for the determination of tariff as under:

"Section 61 (Tariff regulations):

The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:

(a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;

(b) The generation, transmission, distribution and supply of electricity are conducted on commercial principles;

(c) The factors which would encourage competition, efficiency, economical use of

the resources, good performance and optimum investments;

(d) *Safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*

(e) *The principles rewarding efficiency in performance;*

(f) *Multiyear tariff principles;*

(g) *That the tariff progressively, reflects the cost of supply of electricity and also, reduces cross-subsidies in the manner specified by the Appropriate Commission;*

(h) *The promotion of co-generation and generation of electricity from renewable sources of energy;*

(i) *The National Electricity Policy and tariff policy:*

Provided that the terms and conditions for determination of tariff under the Electricity (Supply) Act, 1948, the Electricity Regulatory Commission Act, 1998 and the enactments specified in the Schedule as they stood immediately before the appointed date, shall continue to apply for a period of one year or until the terms and conditions for tariff are specified under this section, whichever is earlier."

1.1.5 Section 178 (2) (s) of the Act further empowers the Commission to make regulations on the terms and conditions for the determination of tariff under Section 61 of the Act.

1.2 Tariff Regulations Issued by CERC

1.2.1 The Commission, since its inception, has been issuing regulations based on multi-year tariff principles over the various Control Periods as under:

Tariff Regulations	Issuance	Period	Provisions
CERC (Terms and Conditions of Tariff) Regulations, 2001 (hereinafter referred to as the 2001 Tariff Regulations)	December 2000	2001 - 2004	Section 28 of the erstwhile Electricity Regulatory Commissions Act, 1998
CERC (Terms and Conditions of Tariff) Regulations, 2004 (hereinafter referred to as the 2004 Tariff Regulations)	March 2004	2004 - 2009	Section 178 of the Electricity Act, 2003
CERC (Terms and	January 2009	2009 - 2014	Section 178 of the

Tariff Regulations	Issuance	Period	Provisions
Conditions of Tariff) Regulations, 2009 (hereinafter referred to as the 2009 Tariff Regulations)			Electricity Act, 2003
CERC (Terms and Conditions of Tariff) Regulations, 2014 (hereinafter referred to as the 2014 Tariff Regulations)	February 2014	2014 - 2019	Section 178 of the Electricity Act, 2003

1.2.2 The present tariff period 2014-19 would end on 31st March 2019 and the Commission proposes to specify the terms and conditions of tariff for the next control period, i.e., for 2019-24.

1.3 Consultation Paper for Tariff Regulations, 2019-24

1.3.1 The Staff of the Commission initiated the process of framing tariff regulations for the 2019-24 period by issuing Consultation Paper on Terms and Conditions of Tariff Regulations for Tariff Period 01.04.2019 to 31.03.2024 in the month of May 2018 (hereinafter referred to as the Consultation Paper) and solicited comments of stakeholders on various options for regulatory framework to be considered while framing the new terms and conditions of Tariff Regulations for the Control Period 2019-24. The Consultation Paper was issued to initiate discussions on the changes required, if any, on the existing tariff norms keeping in view the developments in the sector during the ongoing tariff period, current and perceived challenges in the power sector and duly recognizing the need for sustainable market development based on the experiences of the last nineteen years of tariff regulation by the Commission, starting from May 1999. The Consultation Paper was aimed at soliciting preliminary views of the stakeholders on different aspects of tariff setting during the Control Period 2019-24.

1.3.2 Various stakeholders including State Governments, State Electricity Regulatory Commissions (SERCs), Central sector utilities, State sector utilities, private sector utilities, financial and other organizations, and individual experts commented on the Consultation Paper..

1.3.3 The comments received on the Consultation Paper and the observations by the members of Central Advisory Committee meeting held on 6th July 2018 have been uploaded on the website separately. While preparing the Draft Tariff Regulations for 2019-24, the Commission has taken a holistic view of a) the existing economic environment of the power sector in the country; b) issues raised in the Consultation Paper and comments thereon; c) issues otherwise raised by the stakeholders; and a) the last five year's performance of the central sector generating stations and others and inter-State transmission systems.

1.3.4 There were many issues and challenges discussed in the Consultation Paper which have direct or indirect impact on tariff framework. The suggestions or options to address such issues and challenges were sought from the stakeholders. The Commission has considered the comments offered by the stakeholders on various issues. The Consultation Paper has touched upon the issues of wider horizon. However, the Commission in the Draft Tariff Regulations for 2019-24, has included only those issues that are relevant at this stage and which to be addressed immediately considering the present scenario of the power sector.

1.3.5 In this explanatory memorandum, the Discom has the same meaning as "the Distribution Licensee". Similarly, Transco may be read as "the Transmission Licensee".

2 Capital Cost

2.1 Background

2.1.1 The approval of capital cost is the basis for tariff determination in cost plus tariff regime. The capital cost to a large extent determines the extent of competitiveness of the tariff. The capital cost is admitted by the Commission as per the actual capital expenditure incurred on the project, subject to prudence check.

2.1.2 Determination of tariff based on the capital cost parameter has been followed even prior to the inception of Electricity Regulatory Commission. Prior to 1992 and during the period 1992 to 1997 and 1997 to 2001, the capital cost of the project was based on the gross book value as per the audited accounts. The changes in the capital cost by the way of capitalization and foreign exchange rate variation (FERV) were also being accounted for and tariff was being adjusted retrospectively. During the control period 2004-09, the determination of capital cost was based on the actual cost incurred on the project and the project developer was to approach for tariff determination after declaration of commercial operation date. This premise was changed with effect from 1.4.2009, and determination of capital cost was admitted based on the projected capital expenditure. This change facilitated the generating companies or transmission licensees to file their tariff application prior to commissioning of the project and thereby ensured recovery of tariff from beginning of the commercial operation date as against delayed recovery during the previous period. The projected/actual capital expenditure to be submitted by the generating companies or transmission licensees, need to exclude the un-discharged liabilities, for the purpose of capitalization up to the date of commercial operation. Capital cost, apart from the hard cost of the project, also includes interest during construction, financing charges and FERV up to the date of commercial operation of the project. In case of generation projects, any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is adjusted in the capital cost, whereas in case of transmission projects, any revenue earned by using the assets before COD is adjusted in the capital cost.

2.1.3 In the 2004 Tariff Regulations, the concept of cut-off date was introduced with a view to allow capitalisation of all the necessary works and equipment up to the cut-off date, within the original scope of work, as a part of approved capital cost. The cut-off date was defined as the closing date of financial year immediately after one year of the COD. Subsequently, in case of projects commissioning in the last quarter of the financial year, the cut-off date was extended to the financial year closing after two years of the date of commercial operation of the generating station or the transmission system.

2.1.4 The Commission had specified various provisions regarding the Additional Capital Expenditure in past Tariff Regulations. The 2001 Tariff Regulations and 2004 Tariff Regulations had specified that capital expenditure on account of certain components within the original scope of work, actually incurred after the date of commercial operation and up to the cut-off date may be admitted by the Commission as Additional Capital Expenditure, subject to prudence check. The 2009 Tariff Regulations allowed additional capital expenditure on new assets, incurred after cut-off date for meeting liabilities of arbitration award, decree or order of the court; on account of change in law; and deferred works relating to ash pond or ash handling system in the original scope of work. The Commission continued the provisions for determination of tariff based on the capital expenditure incurred or projected to be incurred in the 2014 Tariff Regulations. As per the Act, the principles of tariff determination mandate balancing of consumer's interest while allowing reasonable returns to the generating company or transmission licensee.

2.1.5 The 2001 Tariff Regulations and the 2004 Tariff Regulations did not include any provisions relating to the benchmark of capital cost for the projects. However, the Commission in the 2009 Tariff Regulations stipulated that in case of thermal generating stations and transmission systems, prudence check of capital cost may be carried out occasionally based on the benchmark norms to be specified by the Commission.

2.1.6 The Commission has also issued separate Order for the benchmark of capital cost of thermal generation project and transmission project (excluding HVDC line). The Tariff Policy, 2016 stipulates that the Commission would evolve benchmark of capital cost as reference to allow reasonable capital cost to the generators or transmission licensees.

2.2 Existing Provisions of the 2014 Tariff Regulations

2.2.1 The existing 2014 Tariff Regulations allow capital cost for the new projects (to be commissioned in the control period 2014-19) based on the expenditure incurred as on date of COD, duly certified by the Auditors after prudence check. For the existing projects, the capital cost admitted by the Commission during the preceding tariff period is being considered along with the additional capitalization during the Control Period after due diligence. Relevant provisions of 2014 Tariff Regulations is extracted below.

"9. Capital Cost: *(1) The Capital cost as determined by the Commission after prudence check in accordance with this regulation shall form the basis of determination of tariff for existing and new projects.*

(2) The Capital Cost of a new project shall include the following:

(a) The expenditure incurred or projected to be incurred up to the date of commercial operation of the project;

(b) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

(c) Increase in cost in contract packages as approved by the Commission;

(d) Interest during construction and incidental expenditure during construction as computed in accordance with Regulation 11 of these regulations;

(e)Capitalised Initial spares subject to the ceiling rates specified in Regulation 13 of these regulations;

(f) Expenditure on account of additional capitalization and de-capitalisation determined in accordance with Regulation 14 of these regulations;

(g) adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the COD as specified under Regulation 18 of these regulations; and

(h) Adjustment of any revenue earned by the transmission licensee by using the assets before COD.

(3) The Capital cost of an existing project shall include the following:

(a) The capital cost admitted by the Commission prior to 1.4.2014 duly trued up by excluding liability, if any, as on 1.4.2014;

(b) Additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with Regulation 14; and

(c) Expenditure on account of renovation and modernisation as admitted by this Commission in accordance with Regulation 15.

(4) The capital cost in case of existing/new hydro generating station shall also

include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and

(b) Cost of the developers 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) project in the affected area.

(5) The capital cost with respect to thermal generating station, incurred or projected to be incurred on account of the Perform, Achieve and Trade (PAT) scheme of Government of India will be considered by the Commission on case to case basis and shall include:

a) Cost of plan proposed by developer in conformity with norms of PAT Scheme; and

b) Sharing of the benefits accrued on account of PAT Scheme.

(6) The following shall be excluded or removed from the capital cost of the existing and new project:

(a) The assets forming part of the project, but not in use;

(b) Decapitalisation of Asset;

(c) In case of hydro generating station any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State government by following a two stage transparent process of bidding; and

(d) The proportionate cost of land which is being used for generating power from generating station based on renewable energy:

Provided that any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment shall be excluded from the Capital Cost for the purpose of computation of interest on loan, Return on Equity and depreciation.

10. Prudence Check of Capital Expenditure: *The following principles shall be adopted for prudence check of capital cost of the existing or new projects:*

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time:

Provided that in cases where benchmark norms have not been specified, prudence check may include scrutiny of the capital expenditure, financing plan, interest during construction, incidental expenditure during construction for its reasonableness, use of efficient technology, cost over-run and time over-run, competitive bidding for procurement and such other matters as may be considered appropriate by the Commission for determination of tariff:

Provided further that in cases where benchmark norms have been specified, the generating company or transmission licensee shall submit the reasons for exceeding the capital cost from benchmark norms to the satisfaction of the Commission for allowing cost above benchmark norms.

(2) The Commission may issue new guidelines or revise the existing guidelines for vetting of capital cost of hydro-electric projects by an independent agency or an expert and in that event the capital cost as vetted by such agency or expert may be considered by the Commission while determining the tariff for the hydro generating station.

(3) The Commission may issue new guidelines or revise the existing guidelines for scrutiny and approval of commissioning schedule of the hydro-electric projects in accordance with the tariff policy issued by the Central Government under section 3 of the Act from time to time which shall be considered for prudence check.

(4) Where the power purchase agreement entered into between the generating company and the beneficiaries provides for ceiling of actual capital expenditure, the Commission shall take into consideration such ceiling for determination of tariff for prudence check of capital cost.

11. Interest during construction (IDC), Incidental Expenditure during Construction (IEDC)

(A) Interest during Construction (IDC):

(1) Interest during construction shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds up to SCOD.

(2) In case of additional costs on account of IDC due to delay in achieving the SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds:

Provided that if the delay is not attributable to the generating company or the transmission licensee as the case may be, and is due to uncontrollable factors as specified in Regulation 12 of these regulations, IDC may be allowed after due prudence check:

Provided further that only IDC on actual loan may be allowed beyond the SCOD to the extent, the delay is found beyond the control of generating company or the transmission licensee, as the case may be, after due prudence and taking into account prudent phasing of funds.

***(B) Incidental Expenditure during Construction (IEDC)**:*

(1) Incidental expenditure during construction shall be computed from the zero date and after taking into account pre-operative expenses up to SCOD: Provided that any revenue earned during construction period up to SCOD on account of interest on deposits or advances, or any other receipts may be taken into account for reduction in incidental expenditure during construction.

(2) In case of additional costs on account of IEDC due to delay in achieving the SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justification with supporting documents for

such delay including the details of incidental expenditure during the period of delay and liquidated damages recovered or recoverable corresponding to the delay:

Provided that if the delay is not attributable to the generating company or the transmission licensee, as the case may be, and is due to uncontrollable factors as specified in regulation 12, IEDC may be allowed after due prudence check:

Provided further that where the delay is attributable to an agency or contractor or supplier engaged by the generating company or the transmission licensee, the liquidated damages recovered from such agency or contractor or supplier shall be taken into account for computation of capital cost.

(3) In case the time over-run beyond SCOD is not admissible after due prudence, the increase of capital cost on account of cost variation corresponding to the period of time over run may be excluded from capitalization irrespective of price variation provisions in the contracts with supplier or contractor of the generating company or the transmission licensee.

12. Controllable and Uncontrollable factors*: The following shall be considered as controllable and uncontrollable factors leading to cost escalation impacting Contract Prices, IDC and IEDC of the project :*

(1) The "controllable factors" shall include but shall not be limited to the following:

- *a) Variations in capital expenditure on account of time and/or cost overruns on account of land acquisition issues;*
- *b) Efficiency in the implementation of the project not involving approved change in scope of such project, change in statutory levies or force majeure events; and*
- *c) 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:

- *i. Force Majeure events; and*
- *ii. Change in law.*

Provided that no additional impact of time overrun or cost over-run shall be allowed on account of non-commissioning of the generating station or associated transmission system by SCOD, as the same should be recovered through Implementation Agreement between the generating company and the transmission licensee:

Provided further that if the generating station is not commissioned on the SCOD of the associated transmission system, the generating company shall bear the IDC or transmission charges if the transmission system is declared under commercial operation by the Commission in accordance with second proviso of Clause 3 of Regulation 4 of these regulations till the generating station is commissioned:

Provided also that if the transmission system is not commissioned on SCOD of *the generating station, the transmission licensee shall arrange the evacuation from the generating station at its own arrangement and cost till the associated transmission system is commissioned.*

13. Initial Spares: *Initial spares shall be capitalised as a percentage of the Plant and Machinery cost up to cut-off date, subject to following ceiling norms:*

(a) Coal-based/lignite-fired thermal generating stations	-	*4.0%*
(b) Gas Turbine/Combined Cycle thermal generating stations	-	*4.0%*
(c) Hydro generating stations including pumped storage hydro generating station.	-	*4.0%*
(d) Transmission system		
(i) Transmission line	-	*1.00%*
(ii) Transmission Sub-station (Green Field)	-	*4.00%*
(iii) Transmission Sub-station (Brown Field)	-	*6.00%*
(iv) Series Compensation devices and HVDC Station	-	*4.00%*
(v) Gas Insulated Sub-station (GIS)	-	*5.00%*
(vi) Communication system	-	*3.5%*

Provided that:

i. *where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost by the Commission, such norms shall apply to the exclusion of the norms specified above:*
ii. *where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipments shall be as per the ceiling norms specified for transmission system under these regulations:*
iii. *once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:*
iv. *for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as project cost as on cut-off date excluding IDC, IEDC, Land Cost and cost of civil works. The transmission licensee shall submit the break up of head wise IDC & IEDC in its tariff application.*

14. Additional Capitalisation and De-capitalisation:

(1) The capital expenditure in respect of the new project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Undischarged liabilities recognized to be payable at a future date;

(ii) Works deferred for execution;

(iii) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 13;

(iv)Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law; and

(v) Change in law or compliance of any existing law:

Provided that the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities recognized to be payable at a future date and the works deferred for execution shall be submitted along with the application for determination of tariff.

(2) The capital expenditure incurred or projected to be incurred in respect of the new project on the following counts within the original scope of work after the cut-off date may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Deferred works relating to ash pond or ash handling system in the original scope of work; and

(iv) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.

(3) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts after the cut-off date, may be admitted by the Commission, subject to prudence check:

(i) Liabilities to meet award of arbitration or for compliance of the order or decree of a court of law;

(ii) Change in law or compliance of any existing law;

(iii) Any expenses to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Government Agencies of statutory authorities responsible for national security/internal security;

(iv)Deferred works relating to ash pond or ash handling system in the original scope of work;

(v) Any liability for works executed prior to the cut-off date, after prudence check of the details of such undischarged liability, total estimated cost of package, reasons for such withholding of payment and release of such payments etc.;

(vi)Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;

(vii) Any additional capital expenditure which has become necessary for efficient operation of generating station other than coal/lignite based stations or transmission system as the case may be. The claim shall be substantiated with the technical

justification duly supported by the documentary evidence like test results carried out by an independent agency in case of deterioration of assets, report of an independent agency in case of damage caused by natural calamities, obsolescence of technology, up-gradation of capacity for the technical reason such as increase in fault level;

(viii) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) and due to geological reasons after adjusting the proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;

(ix) In case of transmission system, any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolesce of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and

(x) Any capital expenditure found justified after prudence check necessitated on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply corresponding to full coal linkage in respect of thermal generating station as result of circumstances not within the control of the generating station:

Provided that any expenditure on acquiring the minor items or the assets including tools and tackles, furniture, air-conditioners, voltage stabilizers, refrigerators, coolers, computers, fans, washing machines, heat convectors, mattresses, carpets etc. brought after the cut-off date shall not be considered for additional capitalization for determination of tariff w.e.f. 1.4.2014:

Provided further that any capital expenditure other than that of the nature specified above in (i) to (iv) in case of coal/lignite based station shall be met out of compensation allowance:

Provided also that if any expenditure has been claimed under Renovation and Modernisation (R&M), repairs and maintenance under (O&M) expenses and Compensation Allowance, same expenditure cannot be claimed under this regulation.

(4) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of decapitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place, duly taking into consideration the year in which it was capitalised."

2.3 Issues discussed in the Consultation Paper

2.3.1 Following issues had been brought out in the Consultation:

(i) Variation between projected capital cost vis-a-vis actual capital cost of the project.

(ii) Additional capital expenditure estimated up to cut-off date on account of reasons like deferment in commissioning of projects, non-placement of orders due to limited vendor responses, etc.

(iii) Delay in project execution takes place due to various reasons such as delay in land acquisition, delay in getting statutory approvals/clearances, delay due to geographical location of the site, delay on the part of contractor/supplier of material, execution philosophy, etc., leading to increase in IDC, overhead expenses, etc.

(iv) Absence of benchmark capital cost, leading to the use of the estimated capital cost as per investment approval for reference purpose. Estimated capital cost as per investment approval may not truly reflect the efficiency in procurement and execution of the project when compared to market rates.

(v) Use of the audited annual accounts to ascertain the claim of the capital expenses. The tariff filing forms have been prescribed for filing regulatory information to facilitate reconciliation with financial statements prepared as per accounting standards. The financial statements of power companies have been changed w.e.f. 1st April 2016 due to the introduction of Indian Accounting Standards Rules, 2015. The formats for filing regulatory information may need to be reviewed in this context.

(vi) On the basis of indicative location, fuel and estimated cost of the generating station (investment approval) the beneficiaries enter into power purchase agreement and undertake the obligations to off-take the power upon commercial operation of the project. Often, on declaring commercial operation, the generating companies revise the investment and the beneficiaries may not be aware of the revised estimated cost. Similarly, the transmission licensees also revise the costs, which the customers may not be aware of.

(vii) The claims of deferred works were allowed to be capitalised up to the cut-off date under the head "works deferred for execution/deferred works" but there is no provision for allowing such expenses after cut-off date in the 2014 Tariff Regulations. In some of the cases, expenditure was allowed even after cut-off date.

(viii) The 2014 Tariff Regulations provides for specific treatment of expenses of capital nature at the fag-end of project life and allows allowances which had consequential impact on tariff as entire depreciation would have to be charged within balance useful life. This provision may need review in view of the policy of phasing out of old plants and expected benefit for getting dispatch after completion of useful life.

(ix) There may be need for provisions for additional capitalization that may be required by thermal generators to meet the efficiency improvement targets under the Perform, Achieve & Trade (PAT) scheme, water from Sewage Thermal Plant (STP), equipment to meet revised standards of emission norms, adoption of storage facility and combining renewable generation with thermal power project.

(x) The efficacy of normative Compensation Allowance and Special Allowance may need to be reviewed vis-à-vis actual expenditure. The regulatory oversight may be required to address overlapping of expenditure under Compensation Allowance and O&M expenses.

(xi) Provisions to handle capital expenditure to comply with new environmental norms, expenditure due to change in law (whether it is possible to specify events), servicing of expenditure relating to rail infrastructure, availability of wagons etc. to tackle major breakdowns and expenditure relating to grid security.

(xii) The trend of capital cost of hydro generating stations indicates that these are becoming un-viable due to higher tariff. The present approach may need to be reviewed in view of sustainable benefits offered by such stations in terms of clean power and high ramping rates.

2.3.2 While suggestions were sought from the stakeholders, the Consultation Paper itself discussed few options for controlling capital cost:

(i) Move from investment approval as reference cost to benchmark/reference cost for prudence check. However, the challenge is absence of credible benchmarking of technology and capital cost.

(ii) In new projects, restrict the fixed rate of return to the normative equity as envisaged in the investment approval or benchmark cost and allow return on additional equity at the rate of weighted average of interest rate of loan portfolio or rate of Risk Free Return.

(iii) Introduce incentive for early completion and disincentive for slippage from scheduled commissioning date.

2.4 Stakeholders' Response

2.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted their comments/suggestions on various issues. The summary of comments/suggestions as submitted by the stakeholders is as follows:

Benchmark Capital Cost:

2.4.2 With regard to benchmarking of capital cost, the comments and suggestions of the stakeholders received are as under:

a) KERC suggested that benchmarking of capital cost is not practicable, as the cost varies from State to State depending upon the geographical conditions and local laws.

b) Various central sector generating companies and transmission licensees submitted that the econometric analysis or benchmarking for determination of capital cost is not advisable.

c) Various State sector generating companies and transmission licensees submitted that the Commission may continue with the present methodology for determination of capital cost with prudence check.

d) Most of the private sector generating companies and transmission licensees submitted that the number of variable factors in generating stations or transmission lines are so high that each plant/line is unique, as far as design and investment is concerned and, therefore, it is practically impossible to define the benchmark cost.

e) Some private utilities suggested that benchmarking should be done only for future projects and not for the existing projects.

f) Various Discoms suggested that shifting from Investment approval to benchmark cost based on current market conditions will lead to a healthier market. Even the concept of dynamic benchmarking may be considered for optimization of the cost. Benchmark norms for capital cost and spares should be determined periodically for different size of thermal units/ transmission elements considering the improvements/ advancements in technology to improve the efficiency.

g) Some private stakeholders and individuals were not in favour of changing the capital cost calculation from the existing method to the normative method.

Alternative Option to Benchmark Capital Cost

2.4.3 The comments and suggestions of the stakeholders received are as under:

a) KERC supported the proposal that the return on additional equity may be restricted to the extent of weighted average interest rate of loan portfolio or rate of Risk Free return.

b) Some Central Generating Companies suggested that it will not be prudent to reduce the return on excess equity, infusion of which is beyond the control of generating company. The present concept of working out equity base should be continued.

c) Stakeholders submitted that restricting the rate of return on the normative equity and allowing return on additional equity based on weighted average interest rate of loan or Risk Free rate is against the very concept of Return on Equity which has to be greater than the cost of debt.

d) State sectors welcomed the suggestion to restrict fixed rate of Return on Equity to normative equity on benchmark cost. The return on additional equity should be based on Risk Free Rate of Return on Government Securities (G-Sec) or RBI bank rate.

e) Stakeholders submitted that return should be applicable on the total equity amount and RoE be allowed to the project developer during construction period also.

f) Limiting return on additional capital expenditure may discourage generators, as infusion of equity is always required for financing as 100% debt is hardly available.

g) Stakeholders submitted that additional capital requirement due to change in law or deferred work after the cut-off date beyond COD should be allowed and return should be linked to normative equity for approved project cost and not to the benchmark cost.

h) Various private sector companies suggested that return on additional equity should not be restricted to weighted average loan portfolio, as it may make the project financially unviable .

i) Stakeholders highlighted that the Commission should allow return on additional equity above the normative equity to the extent of weighted average of interest rate of actual loan portfolio of the project.

j) Various Discoms commented that providing full return on the additional capital cost is unfair to the beneficiaries. Accordingly, the proposed rationalization of return is a welcome step and is fair to both the sides. Cost overrun due to uncontrollable factors, could be shared amongst generators/transmission utilities and beneficiaries.

k) Few private stakeholders submitted that reduction in reasonable return to shareholders for the cost overrun allowed by the Commission would imply imposition of penalty for no fault of the developer and is therefore not desirable. This would in turn reduce the cash flow to reserves for funding future growth.

Incentive for Early Completion and Disincentive for Slippage from Scheduled Commissioning Date

2.4.4 The comments and suggestions of the stakeholders received on the above issue are as under:

a) KERC supported the proposal to introduce of incentive for early completion and disincentive for slippage from scheduled commissioning.

b) Various Central sector companies were of the view that incentive for timely completion of the projects is already there in the form of additional RoE of 0.5% and the generator loses out on this additional return in case of delay of the project. Since no RoE is allowed in the tariff during the construction period, the effective RoE reduces due to delays, placing the generator at disadvantage. The proposal to further reduce the RoE in case of delays would effectively amount to double penalizing the generator for the same cause.

c) Various State sector companies submitted that there should be not disincentive for delay in completion of the project.

d) Stakeholders suggested that instead of framing new provision for incentives and disincentives for timely and delayed commissioning of projects respectively, the existing provisions needs to be integrated.

e) Various private sector companies submitted that delay in commissioning due to reasons beyond the control of generator should not result in disincentive.

f) Various Discoms submitted that the prevailing scenario of early completion is rewarded by 0.5% in RoE, whereas the risk is forfeiting of only IDC which is only partially disallowed on most occasions. Further, the additional burden of IDC is also split between debt and equity thereby increasing the RoE on account of delay. Hence, they suggested to have a re-look at the prevailing incentive and disincentive schemes to balance the risk and reward.

g) Stakeholders suggested that the disincentive for any time and cost overrun due to slippage from scheduled commissioning date should be reduced from the capital cost of the plant.

h) Some private stakeholders submitted that the incentive for early completion of the project from scheduled commissioning may be linked with an additional post-tax Return on Equity of 0.5% in line with the prevailing 2014 Tariff Regulations.

Other Issues:

2.4.5 The comments and suggestions of the stakeholders received on other issues are as under:

a) Various Discoms suggested that any project cost incurred after the cut-off date should be approved only as an exception and with due care.

b) Stakeholders submitted that additional capitalization after 'Cut-off date' may be allowed only for meeting undischarged liabilities, deferred works, works required as per court orders. All other capital expenses may be met through compensation or special allowance.

c) Some private stakeholders submitted that there should not be any cut-off date for essential expenses based on prudent reasoning.

d) Some of the hydro generating companies suggested that decent returns must be ensured for encouraging investment, else the percentage share of hydro may further deteriorate. Returns during construction period may also be considered to be paid by the developers.

2.5 Commission's Proposal

2.5.1 The Commission has carefully examined and reviewed the stakeholders' comments/suggestions received.

2.5.2 The Commission has observed that the benchmarking of capital cost model for generation and transmission was introduced by the Commission vide Order dated 16.6.2010 and 27.4.2010 in respect of transmission system and 4.6.2012 in respect of thermal power station using coal respectively. However, the Commission recognises that there is a need to develop an effective capital cost benchmarking model duly taking into account implementation difficulties and complexities involved. Accordingly, the Commission has decided to prescribe new proforma for obtaining relevant data for benchmarking of capital cost and reintroduce the same in revised form and manner at a later stage for effective implementation. In the meantime, in order to control the capital cost, the Commission has proposed to adopt some of the alternative options as discussed in the Consultation Paper with suitable modifications.

2.5.3 The Commission observed that there are several new capital expenditure items envisaged on account of new developments in the power sector namely biomass handling equipment for co-firing, ash utilisation, emission control system, fulfilment of any conditions for obtaining environmental clearance for the project etc., which are required to be mentioned in the capital cost. Besides, certain type of capital expenditure, which have been forming part of capital cost of the project, but not mentioned specifically, namely capital expenditure on ash handling including transportation facility, railway infrastructure and its augmentation for transportation of coal upto generating station receiving end. FERV on loans during project construction period shall also be included in the capital cost. There is a need to bring in more clarity in the capital cost related provisions.

2.5.4 Regarding prudence check of the capital cost, the Commission has proposed to analyse capital cost of similar projects based on historical data, wherever available, while scrutinising capital expenditure of a thermal generating stations or transmission system. The Commission has proposed to seek package wise capital cost data for existing as well as new projects from generating companies and transmission licensees, for creating database of benchmark capital cost of various components of a thermal generation station and transmission system.

2.5.5 The Commission has observed while dealing with tariff petitions, that matters pertaining to acquisition of land or getting right of way, have become one of the main causes of delay in commissioning of projects. In the existing 2014 Tariff Regulations, only force majeure and change in law have been specifically identified as uncontrollable factors. However, the Commission has noticed that, land acquisition and Right of Way issues have been largely outside the control of the project developer and accordingly, the Commission has also been condoning the delay and allowing the associated cost to form part of the capital cost. In the light of these practical issues, the Commission has proposed to include time and cost over-runs on account of land acquisition, as an uncontrollable factor, except where the delay is attributable to the generating company or the transmission licensee, such as not complying with the timeline for making application, or complying with specific requirements.

2.5.6 The Commission has also proposed to clearly segregate the a) additional capitalisation within the original scope and upto cut-off date, b) additional capitalisation within original scope and after cut-off date and c) additional capitalisation beyond the original scope, in terms of treatment of these w.r.t rate of return on equity. It has been proposed that equity component up to 30% of the additional capital expenditure incurred after the cut-off date, whether within the original scope or not, shall be serviced at the weighted average rate of interest.

2.5.7 It is noticed that there is not much difference between the initial spares of green field and brown field substations. Further, the initial spares of all compensation devices including series and shunt compensation and HVDC are kept at the same. The Commission proposes to maintain same level of initial spares for green field and brown field substation.

2.5.8 The existing 2014 Tariff Regulations consists of a provision to allow additional capital expenditure which is necessitated on account of efficient operations of generating stations other than coal/lignite based generating stations or transmission system. As this clause provides a wide window for additional capital expenditure, which normally should be limited only on account of force majeure or change in law, the Commission has proposed to drop this clause.

2.6 Proposed Provisions

2.6.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders has proposed Regulation 18 to 25 in the Draft Tariff Regulations that is reproduced below:-

"18. Capital Cost: (1) The Capital cost of the generating station or the transmission system, as the case may be, as determined by the Commission after prudence check in accordance with these regulations shall form the basis for determination of tariff for existing and new projects.

(2) The Capital Cost of a new project shall include the following:

(a) the expenditure incurred up to the date of commercial operation of the project;

(b) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

(c) Any gain or loss on account of foreign exchange risk variation pertaining to the loan amount availed during the construction period;

(d) Interest during construction and incidental expenditure during construction as computed in accordance with these regulations;

(e) Capitalised initial spares subject to the ceiling rates in accordance with these regulations;

(f) Expenditure on account of additional capitalization and de-capitalisation determined in accordance with these regulations;

(g) Adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the date of commercial operation as specified under Regulation 7 of these regulations; and

(h) Adjustment of any revenue earned by the transmission licensee by using the assets before the date of commercial operation.

(i) Capital expenditure incurred on the ash utilisation, handling including transportation facility as a part of ash disposal of thermal generating station;

(j) Capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal upto the receiving end of the generating station.

(k) Expenditure on account of biomass handling equipment, if any, for co-firing;

(l) Expenditure on account of emission control system necessary to meet the applicable emission standards of notified by Government;

(m) Expenditure on account of fulfilment of any conditions for obtaining environment clearance for the project;

(n) Expenditure on account of change in law and force majeure events.

(o) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

(3) The Capital cost of an existing project shall include the following:

(a) Capital cost admitted by the Commission prior to 1.4.2019 duly trued up by excluding liability, if any, as on 1.4.2019;

(b) additional capitalization and de-capitalization for the respective year of tariff as determined in accordance with these regulations;

and

(c) expenditure on account of renovation and modernisation as admitted by this Commission in accordance with these regulations;

(d) capital expenditure on account of ash disposal including handling and transportation facility;

(e) capital expenditure incurred towards railway infrastructure and its augmentation for transportation of coal upto the receiving end of generating station but does not include the transportation cost and any other appurtenant cost paid to the railway;

(f) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

(4) The capital cost in case of existing or new hydro generating station shall also include:

(a) cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and

(b) cost of the developer’s 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.

(5) The following shall be excluded from the capital cost of the existing and new projects:

(a) The assets forming part of the project, but not in use (to be declared at the time of filing tariff petition);

(b) De-capitalisation of Assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project;

(c) In case of hydro generating station any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State Government by following a transparent process;

(d) Proportionate cost of land of the existing project which is being used for generating power from generating station based on renewable energy:

(e) Any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment;

19. Prudence Check of Capital Expenditure: The following principles shall be adopted for prudence check of capital cost of the existing or new projects:

(1) In case of the thermal generating station and the transmission system, prudence check of capital cost shall include scrutiny of the capital expenditure, in the light of capital cost of similar projects based on past historical data, wherever available, reasonableness of financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost over-run and time over-run, procurement of equipments and materials through competitive bidding and such other matters as may be considered appropriate by the Commission for determination of tariff:

Provided that, while carrying out the prudence check, the Commission shall also examine whether the generating company or transmission licensee, as the case may be, has been careful in its judgments and decisions in execution of the project.

(2) The Commission may, for the purpose of vetting of capital cost of hydro-electric projects, appoint an independent agency or an expert body:

Provided that the Designated Independent Agency already appointed under the guidelines issued by the Commission under 2009-14 Regulations shall continue till completion of the assigned project.

(3) The generating company or the transmission licensee, as the case may be, shall furnish the package wise capital cost for execution of the existing and new projects as per **Annexure-I** along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.

20. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC)

(1) Interest during construction (IDC) shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto SCOD.

(2) Incidental expenditure during construction (IEDC) shall be computed from the zero date, taking into account pre-operative expenses upto SCOD:

Provided that any revenue earned during construction period up to SCOD on account of interest on deposits or advances, or any other receipts shall be taken into account for reduction in incidental expenditure during construction.

(3) In case of additional costs on account of IDC and IEDC due to delay in achieving the SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds in case of IDC and details of incidental expenditure during the period of delay and liquidated damages recovered or recoverable corresponding to the delay in case of IEDC.

(4) If the entire period of delay is not attributable to the generating company or the transmission licensee, IDC and IEDC beyond SCOD may be allowed after due prudence check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system, as the case may be.

(5) If the delay is attributable either in entirety on in part to the generating company or the transmission licensee or its contractor or supplier or agency, in such cases, IDC and IEDC beyond SCOD may be disallowed after due prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, as the case may be.

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 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;

22. Initial Spares: Initial spares shall be capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:

(a)	Coal-based/lignite-fired thermal generating stations	-	4.0%
(b)	Gas Turbine/Combined Cycle thermal generating stations	-	4.0%
(c)	Hydro generating stations including pumped storage hydro generating station.	-	4.0%
(d)	Transmission system		
	(i) Transmission line	-	1.00%
	(ii) Transmission Sub-station	-	4.00%
	(iii) Series Compensation devices and HVDC Station	-	4.00%
	(iv) Gas Insulated Sub-station (GIS)	-	5.00%
	(v) Communication system	-	3.50%

Provided that:

i. where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost by the Commission, such norms shall apply to the exclusion of the norms specified above:

ii. where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipment shall be as per the ceiling norms specified for transmission system under these regulations:

iii. once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:

iv. for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as project cost as on cut-off date excluding IDC, IEDC, Land Cost and cost of civil works. The generating company or the transmission licensee shall submit the break-up of head wise IDC & IEDC in its tariff application.

23. Additional Capitalisation within the original scope and upto the cut-off date:

(1) The capital expenditure in respect of the new project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Undischarged liabilities recognized to be payable at a future date;

(b) Works deferred for execution;

(c) Procurement of initial capital spares within the original scope of work, in accordance with the provisions of Regulation 22 of these regulations;

(d) Liabilities to meet award of arbitration or for compliance of the directions or order of any statutory authority or the order or decree of any court of law; Change in law or compliance of any existing law within the cut-off date; and

(e) Force Majeure events;

Provided that in case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization.

(2) The generating company or the transmission licensee, as the case may be shall submit the details of works asset wise/work wise included in the original scope of work along with estimates of expenditure, liabilities

recognized to be payable at a future date and the works deferred for execution.

24. Additional Capitalisation within the original scope and after the cut-off date:

(1) The additional capital expenditure incurred or projected to be incurred in respect of an existing project or a new project on the following counts within the original scope of work and after the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Liabilities to meet award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Deferred works relating to ash pond or ash handling system in the original scope of work;

(d) Liability for works executed prior to the cut-off date;

(e) Works covered under original scope but executed after the cut-off date ;

(f) Liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments; and

(g) Additional capitalization on account of raising of ash dyke as a part of ash disposal system.

(2) In case of replacement of assets deployed under the original scope of the existing project after cut-off date, the additional capitalization may be admitted by the Commission, after making necessary adjustments in the gross fixed assets and the cumulative depreciation, subject to prudence check on the following grounds:

(a) The useful life of the assets is not commensurate with the useful life of the project and such assets have been fully depreciated in accordance with the provisions of these regulations;

(b) The replacement of the asset is necessary on account of change in law or Force Majeure conditions; or

(c) The replacement of such asset has otherwise been allowed by the Commission based on sufficient grounds.

25. Additional Capitalisation beyond the original scope:

(1) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope, may be admitted by the Commission, subject to prudence check:

(a) Liabilities to meet award of arbitration or for compliance of the order or directions in the order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Force Majeure Events;

(d) Any capital expenditure to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Indian Government Instrumentality or statutory authorities responsible for national or internal security;

(e) Deferred works relating to ash pond or ash handling system in additional to the original scope of work, on case to case basis;

Provided also that if any expenditure has been claimed under Renovation and Modernisation (R&M) or repairs and maintenance under O&M expenses, same expenditure cannot be claimed under this Regulation.

(2) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised."

3 Renovation and Modernisation

3.1 Background

3.1.1 The generating companies and the transmission licensees are allowed to undertake Renovation and Modernisation (R&M) for extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. The admissibility of the R&M claim is required to be supported by a Project Report containing information about reference date, financial package, phasing of expenditure, schedule of completion, useful life, reference price level, estimated completion cost, record of consultation with beneficiaries, etc. In the 2009 Tariff Regulations, the Commission introduced an alternative provision in the form of Special Allowance, in lieu of R&M for coal/lignite based thermal power stations. This provision enabled coal/lignite based thermal power stations to meet the requirement of expenses relating to R&M on completion of 25 years of useful life without resetting of capital base. The provision of Special Allowance continued in the 2014 Tariff Regulations, which has been opted by many generating stations and there has been no fresh Petition filed before the Commission seeking additional capital expenditure for R&M of a thermal generating station in the entire control period 2014-19.

3.1.2 Some of the generating station whose tariff is determined by the Commission, have outlived their 'useful' life, and R&M works have been carried out and/or are proposed. The issue of extension of useful life from 25 to 35 years for thermal generating station and from 35 to 50 years for hydro generating stations had been flagged in the Consultation Paper.

3.2 Existing Provisions of the 2014 Tariff Regulations

*"15. **Renovation and Modernisation:** (1) The generating company or the transmission licensee, as the case may be, for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff of the generating station or a unit thereof or the transmission system or an element thereof, shall make an application before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign*

exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(3) In case of gas/ liquid fuel based open/ combined cycle thermal generating station, any expenditure which has become necessary for renovation of gas turbines/steam turbine after 25 years of operation from its COD and an expenditure necessary due to obsolesce or non-availability of spares for efficient operation of the stations shall be allowed:

Provided that any expenditure included in the R&M on consumables and cost of Components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(4) Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

16. Special Allowance for Coal-based/Lignite fired Thermal Generating station:

(1) In case of coal-based/lignite fired thermal generating station, the generating company, instead of availing R&M may opt to avail a "special allowance" in accordance with the norms specified in this regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof, and in such an event, revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms.

(2) The Special Allowance shall be @ Rs. 7.5 lakh/MW/year for the year 2014-15 and

thereafter escalated @ 6.35% every year during the tariff period 2014-15 to 2018-19, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station:

Provided that in respect of a unit in commercial operation for more than 25 years as on 1.4.2014, this allowance shall be admissible from the year 2014-15:

Provided further that the special allowance for the generating stations, which, in its discretion, has already availed of a "special allowance" in accordance with the norms specified in clause (4) of regulations 10 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff Determination) Regulations, 2009, shall be allowed Special Allowance by escalating the special allowance allowed for the year 2013-14 @ 6.35% every year during the tariff period 2014-15 to 2018-19.

(3) In the event of granting special allowance by the Commission, the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure.

3.3 Issues discussed in the Consultation Paper

3.3.1 The Consultation Paper had raised the following issues pertaining to R&M of generating stations and transmission licensees in general and Special Allowance in case of coal/lignite based thermal generating stations in particular:

a) The generating companies and the transmission licensees are allowed to undertake R&M for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. The admissibility of the R&M claims is required to be supported by, inter-alia, estimated extension of useful life.

b) At times the generating companies file their petitions for R&M without giving estimated life extension period, which makes it difficult to carry out cost benefit analysis. In old plants, R&M works are sometimes claimed without specific life extension. Servicing of such capital expenditure for R&M at the end of useful life of the station without extension of useful life becomes difficult to justify.

c) An alternative provision was made in the 2009 Tariff Regulations in the form of Special Allowance to be allowed in lieu of R&M for coal/lignite based thermal power stations. This provision enabled generating companies to meet the requirement of expenses including R&M on completion of 25 years of useful life to a unit /station without any need for seeking resetting of capital base.

d) The old transmission lines and substations are sometimes inadequate to cater to the new demand due to capacity degradation and obsolescence of technology. However, construction of new transmission lines and sub-stations require high initial capital investment and substantial time towards seeking approvals, tackling right of way (ROW) issues and environmental clearances. R&M with/ without upgradation of existing projects is one of the cost-effective alternatives to increase the power transmission capabilities. The upgradation of transmission line and substation to higher voltages has emerged as a viable alternative to cater to the load growth or transmission requirements. It also offers commercial advantages as some of the original foundations, structures, or equipment can be re-used with minimal modifications.

e) In coastal areas, line structures/ towers, hardware, conductors etc. get rusted due to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement of conductors, hardware, insulators, earth wires, etc. The transmission lines which are in service for more than 25 years are affected due to atmospheric conditions and aging.

3.3.2 The Consultation Paper highlighted key issues with regard to Renovation and Modernisation of transmission system as follows:

The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow R&M (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow Special Allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.

3.4 Stakeholders' Response

3.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions:

a) Some of the stakeholders suggested that R&M cost of transmission system could include Residual Life Assessment (RLA) of sub-stations and transmission lines, upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow R&M for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow Special Allowance for R&M of transmission assets.

b) Various Central sector generating companies and transmission licensees submitted that the Commission should include provisions to encourage and incentivize them to carry out concurrent operation of units and also shutdown of unit for R&M.

c) Some of the stakeholders suggested that the existing provision of Special Allowance is exclusively for meeting the capital expenditure towards R&M. The norm of Rs. 7.5 lakhs per MW per year works out to Rs. 1.2 to Rs. 1.5 crores / MW over a period of 15 years, which is barely sufficient to meet capex requirement of R&M. Therefore, other necessary expenditure related to ash dyke and those to comply with Change in Law events for units of more than 25 years may be allowed separately. Further, it was also suggested that Special Allowance needs to be continued as it is the most cost-effective option for continued efficient generation, without necessitating any additional capitalization or de-capitalization.

d) Few State sector companies suggested that any cost covered under renovation and modernization is to be approved under the head R&M Expenses along with period of life extension beyond the designated useful life of the generating station. There should not be any provision in the Tariff Regulations for 'Special Allowance' for incurring the expenditure towards 'Renovation and Modernization', without guarantee of any tangible benefit to beneficiaries in terms of life extension.

e) Some Discoms suggested that in the present scenario where renewable energy plays a major role, and thermal generating stations are not running at the full capacity. Therefore, deterioration of plant and equipment will not be the same as was before when the Plant Load Factor (PLF) was higher for thermal generating stations.. Therefore, the option of allowing the R&M expenses should be considered based on the Normative Annual Plant Availability Factor (NAPAF) achieved by the plant in the previous years and should not be always based on the life of the generating station as default. In case of transmission assets, as a first option, the Commission may allow Special Allowance, instead of R&M, as well-maintained substations/transmission elements do not warrant total replacement at the end of their 'useful' life period.

f) Few Discoms suggested that the Commission may ensure that transmission licensee should not get compensation and Special Allowance for the same assets. Further, the Commission should have a relook at the quantum of Special allowance to ensure that transmission licensees are not making undue profits.

g) Some private stakeholders suggested that R&M should be allowed to be undertaken after specified years of service. Further, depreciation and debt servicing cost of the Additional Capitalization should be allowed to be recovered within the balance useful life of the plant after considering the life extension, if any. As an alternative, the Commission may allow Special Allowance on cumulative basis for the eligible plants and allow the balance capital cost for addition to the GFA.

3.5 Commission's Proposal

3.5.1 After examining and reviewing the comments/suggestions of stakeholders, the Commission has proposed as follows:

<u>Renovation and Modernisation</u>

3.5.2 The Commission is of the view that the provision for R&M for the purpose of extension of life beyond the useful life of generating stations and transmission assets is essential. The provision for R&M will ensure availability of well-maintained generating stations and transmission systems to the beneficiaries at reduced cost as compared to their replacement with new generating stations and transmission systems, as they would require higher initial capital investment and substantial time towards seeking approvals. Further, another feature of R&M is re-determination of the capital cost after deducting the accumulated depreciation already recovered from the original project cost. Hence, the Commission proposes to continue with the provision of admission of additional capital expenditure on account of R&M, but after prudence check.

3.5.3 As part of the prudence check, various beneficiaries have suggested that the generating station should obtain consent from the beneficiaries before applying for R&M. In the current tariff regime, the generating station submits plan for R&M through a tariff petition, before the Commission where beneficiaries get the opportunity to submit their responses. The Commission considers approval of R&M only after undertaking prudence check and carefully considering beneficiaries' comments. However, considering that the R&M is undertaken after completion of original useful life of the asset, it is apt to assume that the expiry of the agreement with the beneficiary would also coincide with the completion of original useful life. However, for the purpose of determination of tariff under provisions of Section 62 of the Act, the continuation of the agreement between the generating station or the transmission licensee and the beneficiary or long term customers, as the case may be, need to be in force. Therefore, the Commission proposes that the generating company or the transmission licensee intending to undertake R&M shall be required to obtain the consent of the beneficiaries or the long term customers, as the case may be, for such R&M and submit the same along with the petition.

<u>Special Allowance</u>

3.5.4 The Commission had introduced the concept of Special Allowance in the 2009 Tariff Regulations and the same continued in the 2014 Tariff Regulations. .. S However, the beneficiaries are often not sure whether the amount claimed under Special Allowance is actually being spent by the generating stations. Further, as against R&M, which necessarily entails extension of life of the generating stations beyond the useful life, Special Allowance is availed on year to year basis for generation and supply of electricity by thermal generating station to the beneficiary.

3.5.5 While Special Allowance has been advantageous to the well maintained coal/lignite based thermal generating stations by allowing them to operate beyond their useful life without reduction in the capital base on account of replacement of assets and without relaxation of operational parameters, it also helps the beneficiaries by making available economical power from old and well maintained generating stations with significantly lower burden on account of fixed cost.

3.5.6 In view of above, the Commission proposes to continue with the provisions of Special Allowance for the control period 2019-24. Further, with a view to bring parity among all generating stations availing Special Allowance during 2009-14 and 2014-19 tariff periods, the Commission has proposed to freeze the Special Allowance figure at Rs. 9.50 Lakh/MW/year for the entire tariff period, without any escalation. The Commission is of the view that this amount of Rs. 9.50 Lakh/MW/year is sufficient to cater to the generating station's requirement.

3.5.7 Further, the Commission has proposed that the generating company in respect of a generating station or unit thereof, opting for 'Special Allowance' instead of availing R&M, shall also constitute a Special Reserve Fund with such 'Special Allowance' for the purpose of undertaking R&M activities only. The Commission has proposed to issue a detailed methodology in this regard subsequently.

3.5.8 Besides Special Allowance, the Commission has also proposed an alternate provision for thermal generating station which have completed 25 years of operation. This provision will be available to those thermal generating stations, which have neither undertaken R&M nor availed Special Allowance. Under this special provision, the generating company and the beneficiary may agree to enter into an arrangement, wherein the total cost (fixed and variable) of the generating station, as determined under these regulations, shall be recovered on scheduled generation basis. Further, under this provision, the beneficiary shall have first right of refusal and in the event of such refusal, the generating company shall be free to sell the electricity generated from such station in a manner it deems fit.

3.6 Proposed Provisions

3.6.1 The Commission, after considering various aspects and taking into account comments and suggestions of the stakeholders, has proposed Regulation 26 to 28 in the Draft Tariff Regulations which is reproduced below:-

"26. Additional Capitalisation on account of Renovation and Modernisation:

(1) The generating company or the transmission licensee, as the case may be intending to undertake renovation and modernization (R&M) of the generating station or unit thereof or transmission system or an element thereof for the purpose of extension of life beyond the originally recognised useful life for the purpose of tariff , shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.

Provided that the generating company or the transmission licensee, as the case may be, making the applications for R&M will not be eligible for Special Allowance under these regulations.

Provided further that, the generating company or the transmission licensee intending to undertake renovation and modernization (R&M) shall be required to obtain the consent of the beneficiaries or the long term customers, as the case may be, for such R&M and submit the same along with the petition.

(2) Where the generating company or the transmission licensee, as the case may be, makes an application for approval of its proposal for renovation and modernisation, approval may be granted after due consideration of reasonableness of the proposed cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, expected duration of life extension, consent of the beneficiaries or long term customers, if obtained, and such other factors as may be considered relevant by the Commission.

(3) In case of gas/ liquid fuel based open/ combined cycle thermal generating station after 25 years of operation from date of commercial

operation, any capital expenditure which has become necessary for renovation of gas turbines/steam turbine or capital expenditure necessary due to obsolescence or non-availability of spares for efficient operation of the stations shall be allowed:

Provided that any expenditure included in the R&M on consumables and cost of components and spares which is generally covered in the O&M expenses during the major overhaul of gas turbine shall be suitably deducted after due prudence from the R&M expenditure to be allowed.

(4) After completion of the R&M, the generating company or the transmission licensee, as the case may be, shall file a petition for determination of tariff. Expenditure incurred or projected to be incurred and admitted by the Commission after prudence check, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

27. Special Allowance for Coal-based/Lignite fired Thermal Generating station:

(1) In case of coal-based/lignite fired thermal generating station, the generating company, instead of availing R&M may opt to avail a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof and in such an event, upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms;

(2) The special allowance shall be available for a generating station which has availed the special allowance during the tariff period 2009-14 or 2014-19 as applicable from the date of completion of the useful life.

(3) The special allowance admissible to the generating station shall be @ Rs 9.5 lakh per MW per year for the tariff period 2019-24.

(4) In the event of availing special allowance, the expenditure incurred or

utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure.

(5) The special allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation & Maintenance activities, for which detailed methodology shall be issued separately.

28. Special Provision for thermal generating 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."

4 Compensation Allowance

4.1 Background

4.1.1 The Commission, in the 2009 Tariff Regulations had introduced the concept of Compensation Allowance to meet the expenses of additional capital expenditure on new asset not within the original scope of work including assets in the nature of minor assets brought after the cut-off date, e.g., roads, buildings, hospitals, schools, club, batteries, computers, telecom, instruments, tools, spares, ACs, fans, coolers, conveyors, relays etc. This was introduced to avoid tedious and time consuming exercise of prudence check of several minor items of capital nature.

4.2 Existing Provisions of the 2014 Tariff Regulations

17. Compensation Allowance:

(1) In case of coal-based or lignite-fired thermal generating station or a unit thereof, a separate compensation allowance shall be admissible to meet expenses on new assets of capital nature which are not admissible under Regulation 14 of these regulations, and in such an event, revision of the capital cost shall not be allowed on account of compensation allowance but the compensation allowance shall be allowed to be recovered separately.

(2) The Compensation Allowance shall be allowed in the following manner from the year following the year of completion of 10, 15, or 20 years of useful life:

Years of Operation	*Compensation Allowance (Rs lakh/MW/year)*
0-10	*Nil*
11-15	*0.20*
16-20	*0.50*
21-25	*1.00*

4.3 Issues discussed in the Consultation Paper

4.3.1 The issue of efficacy of compensation allowance as well as overlapping of items in compensation allowance and O&M Expenses had been discussed in the Consultation Paper.

The efficacy of normative compensation allowance and special allowance may need to be reviewed vis-à-vis actual expenditure. The regulatory oversight may be required to address overlapping of expenditure under compensation allowance and O&M allowance.

…….

There could be overlapping of the O&M expenses and the compensation allowance, due to overlapping of items covered under these two.

4.4 Stakeholders' Response

4.4.1 Few of the stakeholders have suggested that the Commission may relook the provisions of Compensation Allowance to ensure that the generating companies are not making undue profits.

4.4.2 Some of the Discoms have suggested that possible overlapping of O&M expenses and Compensation Allowance lead to higher tariff.

4.4.3 GRIDCO suggested that the 2014 Tariff Regulations allows Compensation Allowance in respect of expenditure of capital nature (not covered under Additional Capitalisation), which is the R&M Expense in disguise without any life extension. Thus, no benefit is derived by the beneficiary(ies)/ consumers. In view of the above and in the interest of consumers, such type of expenditure should be covered under Additional Capitalisation after prudence check on the basis of the petition filed by the generator before the Commission prior to incurring such expenditure.

4.4.4 Few stakeholders highlighted that Compensation Allowance provided to coal based units from 10 to 25 years is for capital expenses of minor nature and is different from the items covered under O&M expenses which are of revenue nature and as such there is no overlap between the two as stated in the Consultation Paper.

4.4.5 Some stakeholders have suggested that Compensation Allowance should be provided in case of gas-based plants (on similar lines as in case of coal-based units) where the useful life has been extended from 15 to 25 years. Some stakeholders stated that the Compensation Allowance provided by the Commission is inadequate and may be enhanced based on the actual past data.

4.5 Commission's Proposal

4.5.1 The Commission has observed during the past two tariff periods that the generating stations are still approaching the Commission for additional capital expenditure for works of minor nature, which was expected to be met out of the Compensation Allowance. Since, the Compensation Allowance is allowed on normative basis and the generating stations are not required to furnish the details of the actual capital expenditure incurred out of such Compensation Allowance, it is difficult to establish whether the Compensation Allowance is serving the desired purpose. The Commission has decided to discontinue the Compensation Allowance and allow the expenditure on capital works of minor nature on actuals and on case to case basis.

4.6 Proposed Provisions

4.6.1 The Commission has decided to discontinue the provisions related to Compensation Allowance.

5 Depreciation

5.1 Background

5.1.1 Depreciation is a major component of the annual fixed cost. Para 5.8.2 of the National Electricity Policy, 2006 provides that *"depreciation reserve is created so as to fully meet the debt service obligation."* The regulatory principle evolved over time stipulates that, there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee during the first 12 years of operation. The depreciation rate has been considered based on the above principle.

5.1.2 The Tariff Policy, 2016 also stipulates that, the Central Commission may notify the rates of depreciation in respect of generation and transmission assets and the rates so notified would be applicable for the purpose of tariffs as well as accounting.

5.1.3 Depreciation depends on three factors, viz., rate base (gross fixed assets on which the rate of depreciation applied), which includes subsequent additions, method of depreciation and useful life.

5.1.4 With regard to rate base, Historical Cost (HC) based approach is used for determining the rate base. The tariff setting approach, whether RoE based or Return on Capital Employed (RoCE) based, has a bearing on rate base.

5.1.5 Straight Line Method (SLM) of depreciation has been used in all the previous four tariff periods. In the context of tariff setting, useful lives of all types of generating stations and transmission systems except gas-based generating stations have remained the same in all the tariff periods. For gas-based stations, life of 15 years was used in tariff periods 2001-04 and 2004-09, which was extended to 25 years in the tariff period 2009-14 and has continued in 2014-19.

5.1.6 In 2001 Tariff Regulations and the 2004 Tariff Regulations, the Commission had adopted the provision of Advance Against Depreciation to ensure that the project has enough cash flows to meet its loan repayment obligations. Over period, this regulatory definition of depreciation viz., "enough cash flow to meet the repayment obligations of the generator during loan repayment period" has gained precedence in tariff setting.

5.1.7 Subsequently, in line with the erstwhile Tariff Policy, 2006 and to have uniformity in depreciation rates for accounting as well as tariff setting; the 2009 Tariff Regulations dispensed with the provision of Advance Against Depreciation (AAD). As a result, the aspect of fair life got delinked in the Tariff Period 2009-14 and 2014-19, at least for the loan repayment period, while setting the depreciation rates.

5.1.8 Accordingly, depreciation rate was worked out by considering the normative repayment period of 12 years to repay long term loan (70% of the capital cost).

5.1.9 There are two types of assets in generation and transmission sector, viz., those developed under cost plus regime (Section 62) and others through competitive bidding (Section 63) under the Electricity Act, 2003. The depreciation rates determined by the Commission are uniformly applicable to both types of assets. Further, within the subset of cost plus assets, several existing units/stations have already outlived or will outlive their originally envisaged useful life during the tariff period of 2019-24. The Commission is required to prescribe treatment of such assets post useful life.

5.2 Existing Provisions of the 2014 Tariff Regulations

*"**27. 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 or element thereof. In case of the tariff of all the units of a generating station or all elements of 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 or elements thereof.*

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 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 10% and depreciation shall be allowed up to maximum of 90% 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 that in case of hydro generating station, the salvage value shall be as provided in the agreement signed by the developers with the State Government for development of the Plant:

Provided further that the capital cost of the assets of the hydro generating station for the purpose of computation of depreciated value shall 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-II 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 depreciable value as on 1.4.2014 shall be worked out by deducting the cumulative depreciation as admitted by the Commission up to 31.3.2014 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 during the fag end of the project (five years before the useful life) along with justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project.

(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."

5.3 Issues discussed in the Consultation Paper

5.3.1 The Consultation paper had discussed the following issues related to Depreciation:

"14.3 In the following circumstances, treatment of depreciation is contingent upon period of extension of useful life or assessment of residual life which would be admissible on satisfying the extension of life:

i) Additional capital expenditure at the end of life or special allowance approved in lieu of renovation and modernisation have consequential impact on the tariff due to recovery of depreciation over balance useful life;

ii) Additional capital expenditure after allowing the special allowance has an impact on recovery of depreciation.

iii) The useful life of Hydro Stations, as specified in Tariff Regulation, 2009, is 35 years. However, the actual life of these Hydro stations may be much more than 35 years. For hydro stations allowing higher depreciation rates during first 12 years results in front loaded tariff. To keep the tariff on lower side, the depreciation rate for hydro stations could be spread over the entire useful life i.e. 35 years. Similarly, for thermal stations, the life may be more than 25 years and the International experience in this regard needs to be looked into to bring further improvements.

14.4 Section 123 of the Companies Act 2013, under Schedule II- provides life of Special Plant and Machinery, as 40 years for generation, transmission and distribution of power whereas Part B of the same has linked useful life to be as specified by regulatory authority. The relevant portion of Part B is extracted under:

"The useful life or residual value of any specific asset, as notified for accounting purposes by a Regulatory Authority constituted under an Act of Parliament or by the Central Government shall be applied in calculating the depreciation to be provided for such asset irrespective of the requirements of this Schedule".

14.5 Books of Accounts are required to be prepared as per Ind AS (Ind Accounting Standard) for generators whose tariff is determined based on regulations notified by Commission. RBI's notification dated July 15, 2014 regarding flexible structuring of long-term project loans to infrastructure and core industries covers power industry. Stipulations relating to depreciation have been laid down in Tariff policy notified on 28 January 2016.

14.6 Options for Regulatory Framework

a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;

b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;

c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment;

d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof;

e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation.

f) Reduce rates, which will act as a ceiling.

g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s)."

5.4 Stakeholders Response

5.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments / suggestions:

I. Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff / Continue with the existing policy of charging depreciation / to keep the tariff on lower side, the depreciation rate for hydro stations could be spread over the entire useful life i.e. 35 years.

a) Several Central sector stakeholders have submitted that any increase or decrease in plant life would require conducting residual life assessment studies, whose results might give rise to disputes due to disagreement and subjectivity. Therefore, the present system of useful life of hydro plants should be continued. If it is uniformly spread over the entire 35 years, cash flow would be severely hit & repayment of loan shall become an issue.

b) Some stakeholders suggested that depreciation rate can be spread over the entire useful life (35 years) of hydro power stations. As the recovery of depreciation is linked with repayment of loan, change in the present Regulations in this regard is required.

c) One of the transmission licensees has submitted that the investment decisions for existing assets were based on the life of assets to be around 25/35 years. If the asset life is increased or depreciation rates are reduced, the servicing of debt would become difficult, pushing the transmission licensee into financial stress. Any change in the regulatory approach in the suggested manner will bring about regulatory uncertainty.

d) Some Central sector stakeholders have suggested that normative useful life for project can be increased with provision for allowing periodical renovation and modernization/ up gradation of electro mechanical /hydro mechanical equipment and some of the Civil structures.

e) One of the transmission licensees has submitted that useful life of the assets to be maintained at 25 years for Delhi Region due to high fault level and pollution leading to frequent breakdowns.

f) Some state sector stakeholders have suggested that increase in the useful life of well-maintained plants may be further elaborated with norms. The increase in useful life for purpose of accounting of depreciation should be considered only after payment of loan as per repayment plan of the plant.

g) Some stakeholders have suggested that in case of increase of useful life of well-maintained plant, depreciation must not be changed, as most of the depreciation must have been recovered over 12 years.

h) Some beneficiaries have suggested that CEA being the technical apex body should be consulted on such issues. The balance depreciation after deducting recovered depreciation from 90% of GFA ought to be equally spread over the extended period to ensure lower tariffs. Reducing depreciation rates or extension of useful life should not lead to any additional expenses in any form as a pass through.

i) It was further submitted that, increasing the useful life of well-maintained plants for the purpose of determination of tariff would benefit the Discoms by reduced depreciation rates for the remaining life period of the asset. Increasing the useful life of well-maintained efficient plants shall result in avoidance of front loading.

j) Some private stakeholders have submitted that with the given 90% depreciation for the entire useful life of the project, the tenure of debt funding should also be increased. In addition, it was suggested that increasing the useful life of plants based on quality of maintenance practices is not a feasible option. Increase in useful life of the asset will result in deferment of the recovery of depreciation under AFC. Any such deferment and thus reduction in depreciation will adversely affect the debt servicing capacity of the developer.

k) Further, increasing the useful life after distinguishing 'well maintained plant' will be a subjective approach. Well-maintained power plants in all probability might have affected the repayment of debt for 12 years of useful life and any enhancement of life will have only marginal effect on depreciation charge/tariff.

II. Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;

a) KERC Central sector stakeholders, State sector stakeholders, private sector stakeholders, other private individuals and organisations have supported the approach

III. Extend useful life of the transmission assets and hydro generating stations to 50 years and that of thermal (coal) generating stations to 35 years and at the same time bring in corresponding changes in treatment of depreciation

a) KERC has supported to the suggestions.

b) Some of the organizations and individuals have also welcomed the suggestion.

c) Some of the central sector stakeholders has submitted that increasing the useful life of hydro generating stations to fifty (50) years and thermal generating stations to thirty-five years (35) with corresponding changes in depreciation rate is in order, as it would reduce the fixed charges significantly.

d) It was also submitted that, life of electromechanical components is not more than 35 years whereas that of civil structures may be longer. After completion of 35 years, the users enjoy the benefit of lower tariff as renovation and modernization needs to be carried out for electromechanical components only and zero depreciation is enjoyed by the beneficiaries for civil structures. Further, it is to be noted that the under-water rotary components in plants of Himalayan region suffer from heavy silt, which adversely affects the life of these components.

e) Some State sector stakeholders have supported the suggestion that the useful life of hydro generating stations and transmission assets should be increased to 50 years instead of prevailing 35 years and that of thermal generating stations should be increased to 35 years. While doing so, the loan repayment period should be increased to 18-20 years from prevailing 10-12 years.

f) It was further submitted that, in respect of new transmission assets, it may not be prudent to increase the useful life to 50 years due to the following reasons:

- An increase in useful life would require procuring equipment designed for a higher life, which would substantially increase the initial capital cost.
- The equipment operating under the Indian grid conditions are heavily stressed primarily due to over voltage condition, frequent faults in downstream system, seasonal pattern, pollution in cities/coastal areas and other specific locational factors resulting in stress in equipment thereby deteriorating the insulation level of the equipment, which influences the life of the equipment.
- The availability of spares and service facility for equipment is limited after 25 years owing to obsolescence, technological upgradation or closing of production line by OEMs/ non-existence of OEM. This affects the ability to maintain the equipment for a longer duration.

g) Many beneficiaries have submitted that extending the useful life of the transmission assets to 50 years and thermal (coal) generating stations to 35 years will reduce the capacity charges at a considerable extent. Increase in the useful life translates into effective reduction in depreciation rates. In addition, depreciation should be charged over the revised balance life of the assets along with the written down value up to 90%of revised GFA.

h) Few beneficiaries have suggested that increasing the useful life of well-maintained efficient plants would result in avoidance of front loading and hence ensure optimum utilization of efficient resources. Reduction of depreciation rates shall have similar effect. It may however, be noted that the interest on loan should also be provided on normative basis, else the benefit of reduced depreciation rates and extended life will be offset by interest payments.

i) Some private companies have expressed a view that increasing the life of thermal generating stations to more than 25 years would not help the generation projects. It is because the tariff for residual life (if any) for generation projects shall be determined after the completion of the existing PPAs and the benefit of such reduced tariff in any way shall be passed on to Discoms.

j) Useful Life of the thermal generating stations should not be increased without consultation with and recommendations based on RLA study.

IV. Consider additional expenditure during the period nearing end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or Special Allowance) to be restricted to limited items/equipment;

a) No comments have been received.

V. Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Indian Accounting Standards and corresponding treatment of depreciation thereof.

a) No comments have been received.

VI. Reduce rates, which will act as a ceiling.

a) One Central sector stakeholder has submitted that it may not be practically feasible to cover all capex items under R&M provisions or through Special Allowance. Capital expenditure towards development of ash dyke, ash-handling system including cost of land that may be required after 25 years and any expenditure required for additional BOP equipment/facilities would need to be considered separately as the same cannot be factored into Special Allowance. Further it would not be possible to estimate requirement of expenditure that may become inevitable because of change in law events concerning environmental and pollution control necessitating up gradation of ESPs or other facilities. Besides, provision of Compensation Allowance available to coal based stations from 11-25 years needs to be extended beyond 25 years, as expenses for which Compensation Allowance is given would also continue to be required after R&M. The Commission based on prudence check of submissions approves the depreciation on capital expenditure during the fag end of the project. The same should be continued in accordance with the existing provisions of the regulations.

b) One of the Central sector stakeholders submitted that the additional expenditure during the fag end of life of a project cannot be the basis for consideration of re-assessment of useful life. A substation consists of large number of equipment. Some of these might need replacement owing to corrective maintenance or preventive maintenance. Such expenditure is towards replacement of faulty equipment to ensure reliability of the system. Further, additional expenditure after Renovation and Modernization (or Special Allowance) should be considered based on prudence check and should not be restricted upfront in the Regulations Additional capital expenditure required to be incurred at the end of useful life for maintaining day-to-day operating efficiency of the project should be considered without re-assessment of useful life. However, additional expenditure on R&M may be considered with re assessment of extended useful life.

c) Some State stakeholders suggested that the assessment of balance useful life is a tedious process that involves substantial expenditures and may not be feasible in real time basis. Therefore, admissibility of additional expenditure for important items/ equipment may be provided. However, above aspects of extension of useful life needs to be exercised along with extension of existing long terms PPA. Therefore, the proposed regulation should have provisions to extend the existing PPA of the power plants to existing beneficiaries.

d) Consideration of additional expenditure towards the end of life of the asset with re-assessment of useful life or admissibility of additional expenditure after renovation and modernization (or Special Allowance) should be restricted to limited items/equipment, which has to be specified by the Commission in consultation with CEA. Further, the guidelines for additional capitalization may be notified by CEA.

e) Some beneficiaries have submitted that many of the Central Generating Stations are achieving full load capacity above NAPAF after serving the useful life of 25 years. While considering this, no additional capital expenditure shall be allowed in terms of extension of the life period.

f) Admissibility of additional expenditure after renovation and modernization should be restricted to limited items and further ascertainment of extension of useful life in lieu of additional expenditure incurred on R&M should be established to compute allowable depreciation.

g) Regarding additional expenditure towards the end of life, the life of such asset needs to be reassessed and the depreciation up to 90% of such additions should be considered in the extended life span.

h) Private stakeholders suggested that rather than restricting additional capitalization to limited items/equipment, the list should be exclusive and exhaustive, i.e. it should contain items which shall not be permitted and other that can be permitted so as to cover genuine items.

i) Additional capital expenditure towards end of life should be added to the net block of assets till date and total amount should be depreciated over the extended life of the project. Further, the treatment of weighted average useful life in case of combination of transmission assets due to commissioning of units at different points of time should continue.

j) Few private organizations suggested that limited items and equipment's need modernization towards the end of useful life. This must be restricted to 10% of the total cost of the equipment.

k) Some private organizations have submitted that R&M projects should be admitted based on the technical reports and should not be restricted to limited items/equipment. Further, there may be requirement of additional capital expenditure due to premature failure of equipment or in order to comply with the stricter statutory norms which, may not necessarily extend life of the entire project. Thus, such schemes may be allowed based on their merit.

l) Many Central sector stakeholders suggested that reassessing life at the start of every tariff period/every additional capital expenditure would lead to inconsistency and add to regulatory uncertainty. The reassessment of life of assets at the beginning of every tariff period may act as a disincentive for proper maintenance of assets.

m) Some State sector stakeholders has suggested that, in case of any additional capitalisation, the effective life should at least be extended to the end of that Control Period.

n) Some beneficiaries have submitted that re-assessing life at the start of every Control Period is a cumbersome job and is not possible to implement.

o) On the other hand, some private stakeholders have submitted that there is no requirement for reassessment of useful life at the start of every tariff period and may be done only at the time of undertaking R&M projects. Reassessment of life at the start of every tariff period is not technically feasible nor it is required since useful life of the power plant has already been technically defined.

p) Many beneficiaries have submitted that reduced rates, which will act, as a ceiling is a welcome step. The reduced rates may be treated as ceiling rates.

q) One of the stakeholders submitted that it is not clear how reduced rates would be set or how 90% depreciation would be ensured at reduced rates.

5.5 Commission's Proposal

5.5.1 The Commission, after reviewing the suggestions received from various stakeholders and considering the concerns raised regarding extension of useful life of generating stations and transmission systems and determination of depreciation proposes the following. 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.

5.5.2 As regards the extension of useful life of the assets, the Commission has undertaken a sample case for sensitivity analysis, which is depicted below:

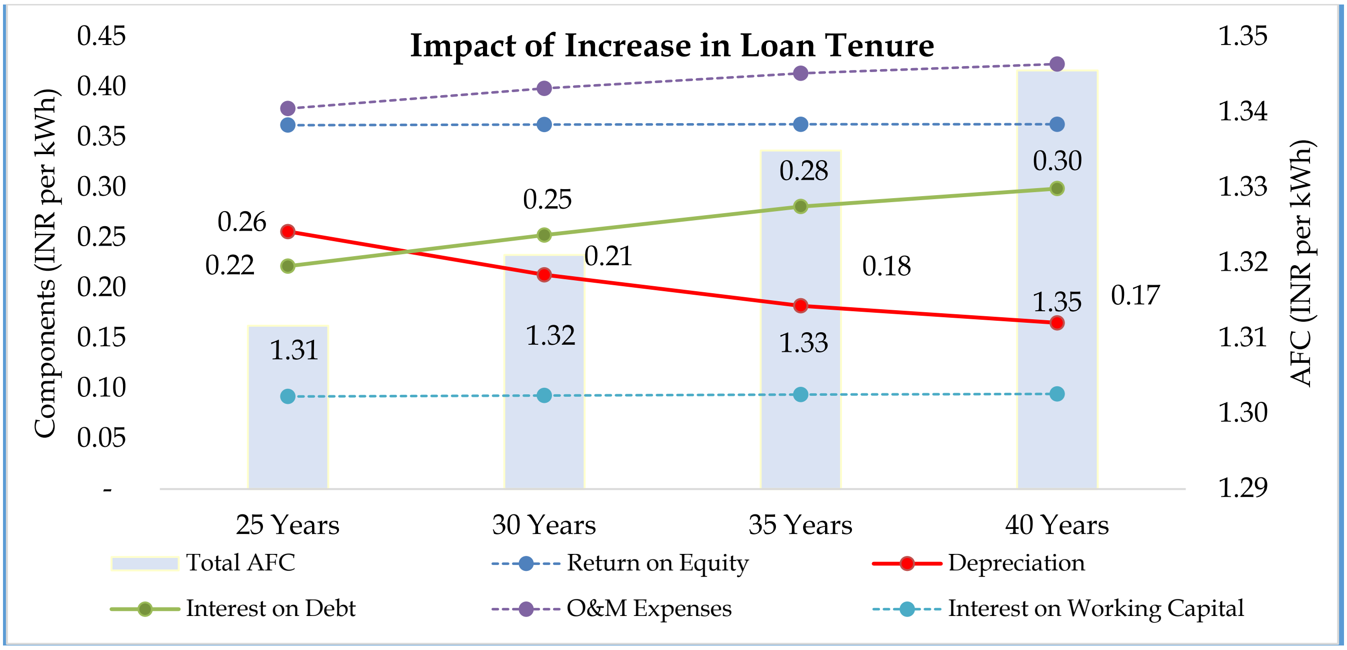


Figure 1: Sensitivity Analysis of Impact of Increase in Loan Tenure

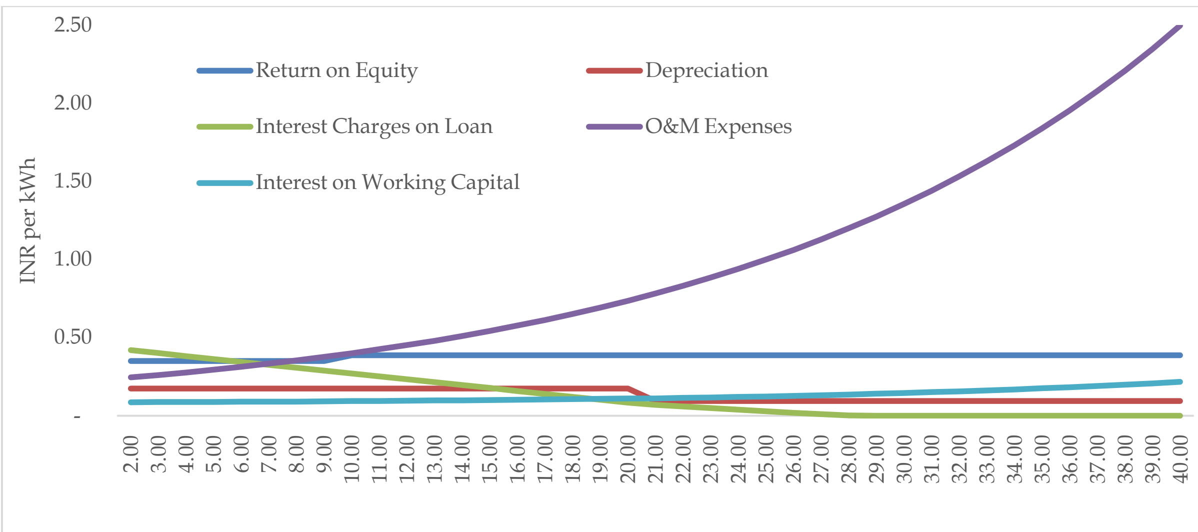


Figure 2: Sensitivity Analysis of Increase in Useful Life of Project

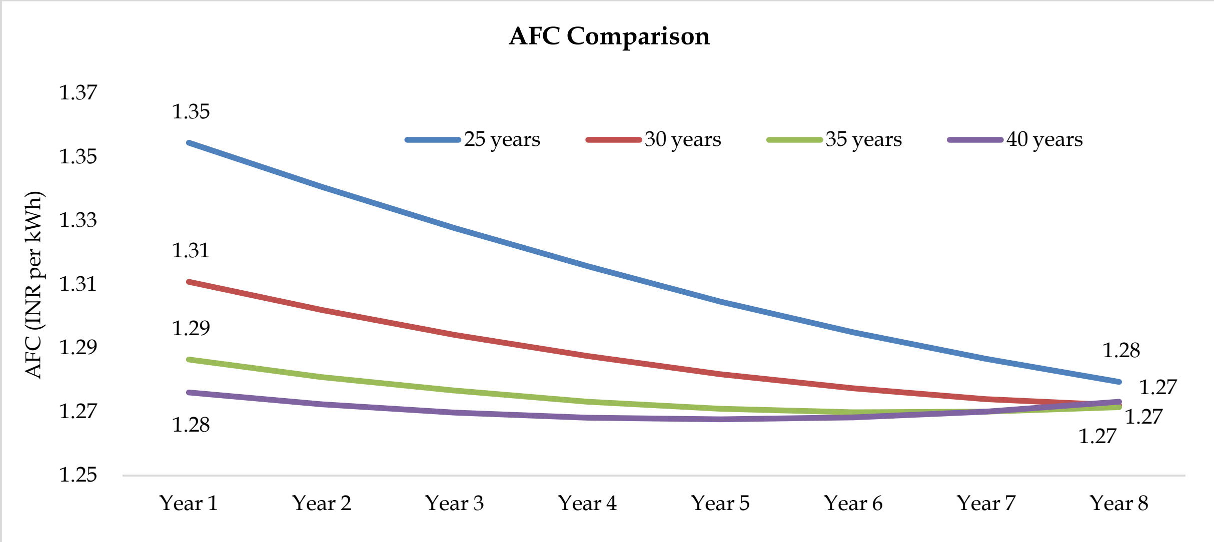


Figure 3: AFC comparison in initial years for different Useful Life

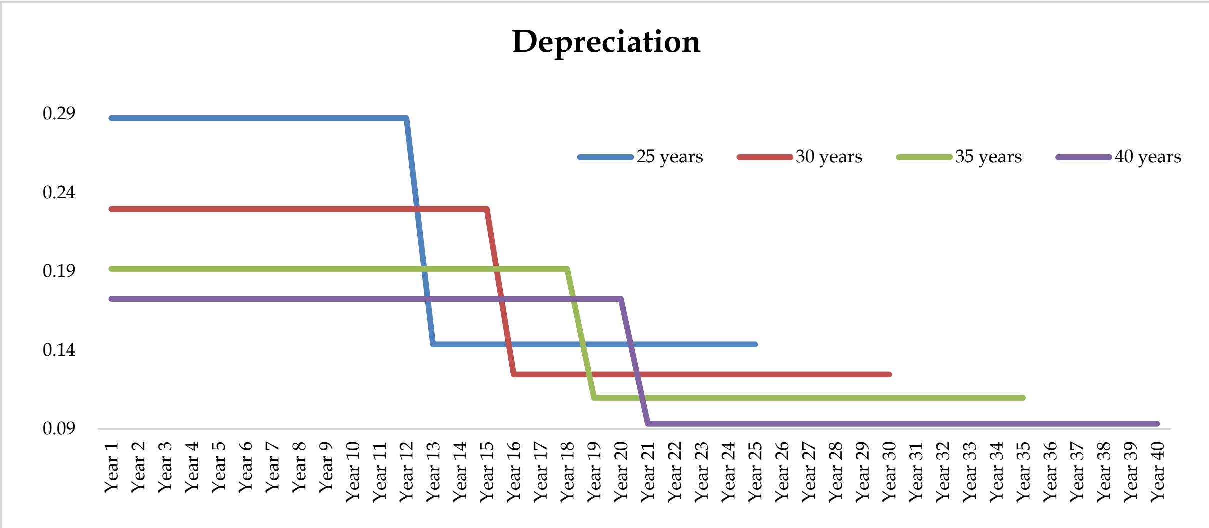


Figure 4: Sensitivity Analysis of Depreciation for different Useful Life

5.5.3 The Commission has observed the following from the sensitivity analysis:

- Increase in useful life, corresponding modification in depreciation rates and loan repayment tenure would result in decrease in depreciation cost component;
- However, a corresponding increase in interest cost component and continued increase in the O&M Expenses would negate the benefit and overall levelised Annual Fixed Cost would increase marginally;
- Increase in useful life, corresponding to the modification in depreciation rates and loan repayment tenure shall result in decrease in depreciation cost component;

5.5.4 5.5.3 Based on the above analysis and noting the technical limitations regarding thermal generating stations as highlighted and suggested by the Stakeholders, the Commission has decided to continue with the existing useful life of 25 years in case of thermal generating stations.

5.5.5 In case of hydro generating stations, it is evident that, these generating stations can serve beyond 35 years of the useful life. Moreover, the mechanical components requiring replacement are comparatively much lesser in case of a hydro generating station as against thermal generating station. Therefore, the Commission has proposed to extend the useful life of hydro generating station from 35 years to 40 years. In addition, an option to charge the depreciation at a flat rate over the entire useful life is proposed in case of the hydro generating station, subject to the condition that the overall depreciation charged does not exceed 95% of the approved capital cost of the generating stations during useful life.

5.5.6 Further, in case of transmission system, the Commission has decided to continue with the existing method of determination of depreciation.

5.5.7 As per Schedule II of the Companies Act, 2013, with the introduction of the concept of useful life for working out depreciation, the companies are allowed to follow different useful lives/residual value if an appropriate justification is provided along with technical advice. However, the said provision also prescribes that the useful life or residual value governed by other regulatory authority shall prevail over Schedule II of Companies Act, 2013. Accordingly, the useful life of generating station or transmission system, as determined by the Commission, shall have precedence over the provisions of Companies Act, 2013.

5.6 Proposed Provisions

5.6.1 In view of above, the Commission proposes Regulation 33 in the Draft Tariff Regulation which is reproduced below:-

"**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 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 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 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.”

6 Gross Fixed Assets Approach Versus Modified GFA Approach

6.1 Background

6.1.1 The Commission in the previous Tariff Regulations had adopted Gross Fixed asset approach as its incentivise the equity investors to efficiently operate and maintain the infrastructure, even after the assets are fully depreciated. It is also evident that, the internal resources generated through depreciation are again employed for further capacity addition. Thus, the GFA approach offer incentives to investors for creating internal resources required for capacity addition and to maintain efficient plant operations.

6.2 Existing Provisions of the 2014 Tariff Regulations

6.2.1 The Commission in the existing regulations, has considered GFA Approach in which, the returns are provided on the normative equity base i.e. 30% or actual equity base, whichever is lower, on a perpetual basis till the asset is utilised. Interest on loan is computed on the normative loan, duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest based on the actual loan portfolio at the beginning of each year applicable to the project, till the normative loan balance becomes nil.

6.3 Issues discussed in the Consultation Paper

6.3.1 The Consultation Paper had brought out the following issues:

"15.1 The Commission in the previous Tariff Regulation has adopted GFA approach as it incentivizes the equity investors to efficiently operate and maintain the infrastructure, even after the plant has been fully depreciated. The internal resources generated by way of depreciation are reutilized for further capacity addition. CEA has estimated that in view of present demand growth rate and availability of commissioned and under construction capacity, no new coal based capacity may be required till 2027.

<u>Option for Regulatory Framework</u>

15.2 An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost."

6.4 Stakeholders' Response

6.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) NHPC has submitted that the suggested approach will significantly affect the returns of a developer, which will affect the investment in the sector. Considering the need of further augmentation in hydropower capacity with penetration of renewable energy, it is imperative that the developers are allowed to build internal accruals for future investments. Thus, the existing approach of allowing return on GFA should be continued. Otherwise the investors will be further discouraged from investing in the hydro sector.

b) NTPC has submitted that the Commission while formulating the 2014Tariff Regulations had discussed the issue in detail and concluded that since investments have been made based on the GFA approach, any change in the methodology for existing projects would have detrimental effect on the returns. Further, in absence of GFA, old stations may be at a loss due to lower RoE and higher risk of under recovery in O&M/operating parameters. Any change in approach would shake the investors' as well as lenders' confidence and would lead to an increase in the interest rate and is, therefore, not in the overall interest of the consumers.

c) It has been submitted that the present tariff structure places the break-even point at around 68% of DC under GFA approach, meaning thereby that RoE is zero at this level of operation and only on achieving 85% of DC the prescribed RoE of 15.5% can be earned. If the Net Fixed Asset approach is followed, the owner's equity in the old power plant will get reduced to 10% of the historical cost and the RoE will be completely wiped off at a DC of around 78%. Thus, any decrease in availability (DC) due to factors beyond the control of the generators, such as fuel availability, logistics of fuel transportation, etc., or increase in O&M expenses over the normative O&M allowed in tariff, will not only result in complete erosion of Return on Equity, but also result in losses and negative cash flow due to which the business growth and survival can be dramatically affected. It is noted that under the Net Fixed Asset approach, the RoE will be a small percentage of AFC. The RoE starts moving down as a percentage of the total cost of power from the 13th year through 25th year (end of the useful life) from 6.15% to 1.2%, whereas under GFA approach it slopes from 6.15 % to 3.47% in the same period.

d) PGCIL has submitted that considering the huge investments required to be made for transmission system, it is imperative that the developers are allowed to generate internal accruals. Thus, the existing approach of allowing return on GFA should be continued.

e) It has been submitted that the Appellate Tribunal of Electricity had passed a judgment dated 16th May 2006 in favour of PGCIL, stating that any mechanism by which the equity is gradually reduced proportionately reducing the rate of return below the specified rate of return is not legal. The judgment was upheld by Hon'ble Supreme Court in its Judgment dated 24th February 2016 in Appeal No. 256 of 2007.

f) In view of above, it is submitted that in case this proposal is adopted, the RoE deployed during construction stage of the project may also be allowed to the developer or the status quo should be maintained. The existing approach should be continued and a higher return may be allowed to PGCIL, if RoCE is adopted for new projects.

g) NEEPCO and NLCIL have submitted that the GFA approach as per the existing policy without reduction of depreciation should continue so that return to the investor based on initial investments are assured. The proposed option of return on the modified gross fixed asset approach would shrink the returns for the generator, which is likely to discourage investors.

h) From the State sector, it is submitted that this would reduce the RoE because in net block approach the equity base will be reduced which will adversely affect the investors. Further, the equity employed in the project remains invested for the whole life of project and accordingly there is direct involvement of opportunity cost for the said period. Thus, the present regulatory practice should be continued. PCKL supported the suggestion of modified GFA wherein, it has submitted that GFA approach may be continued with certain changes, i.e. once the loan amount is repaid, the equity should be reduced in proportion to the deprecation amount paid every year.

i) Some private sector stakeholders have submitted that the implementation of RoCE approach requires stable and mature financial markets for success. The conditions are not yet ripe for such a transition. Further, existing projects have been commissioned under the prevailing approach. Projects, which have completed 20-25 years, having recovered almost full depreciation, would not be much impacted as against projects, which have completed only 8-10 years. Such changes will distort level playing field between old and new projects. In addition, under NFA, approach stake of the project developer will reduce the residual value and developer may not be able to operate the plant efficiently and may not invest in R&M, which will make plant not only uneconomic but also unsafe. This was the condition prior to the formation of regulatory commission and plants were operating at low PLF with more breakdowns. Thus, the modified GFA approach is not advisable in infrastructure company having long-term exposure taken by lenders and investors. Otherwise projects would not get funding.

j) Some of the private sector entities have also submitted to continue with the existing GFA approach, as the Tariff Policy mandates regulatory certainty and any such move will de-motivate the prospective investors. During the previous Tariff Regulations, the approach of returns on modified GFA arrived at by reducing depreciation has not been accepted after elaborate discussion (RoE versus RoCE approach),and hence this approach may not be followed at this stage, since all past implemented projects achieved financial closure assuming returns on GFA basis and not modified GFA. Changing the methodology will increase the perceived risk and banks will charge a higher interest rate which will be passed on to beneficiaries and thereby negating the gains achieved by basing the returns on modified Gross Fixed Assets.

k) Several Discoms have shown their agreement with the proposal of modified GFA approach. In view of present demand growth rate and availability of commissioned and under construction capacity, no new coal based capacity may be required till 2027. Therefore, the returns on modified gross fixed asset would create enough internal resources, though reduced, to be reutilized for further capacity addition, if required at all. Further, provisions should be in line with the concept of "Rate Regulated Base (RRB)", which allow returns on the actual capital invested in the business. In other words, any depreciation in excess of repayment of loans should be treated towards repayment of Equity. Alternately, an interest credit should be provided in the AFC on the amount of depreciation allowed in excess of normative debt.

6.5 Commission's Proposal

6.5.1 To understand the overall impact of the modified GFA approach v/s the existing GFA approach on the levelised tariff, the Commission has undertaken sensitivity analysis as shown below.

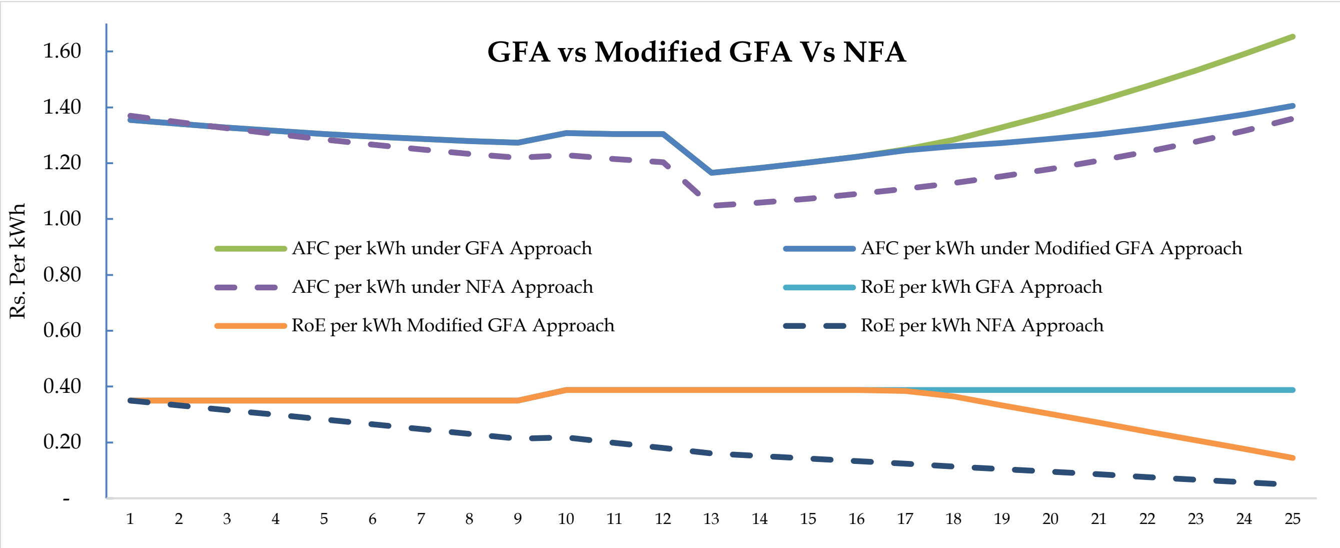


Figure 5: Sensitivity Analysis – GFA vs Modified GFA vs NFA Approaches

6.5.2 In the above sensitivity analysis, under Modified GFA Approach, the adjustment in equity component equivalent to the annual depreciation has commenced after complete repayment of normative debt component till the end of useful life. Accordingly, at the end of useful life of the asset, the remaining equity component is equivalent to the salvage value of the asset. However, if the proposed methodology of Modified GFA Approach is adopted, it would result in disparity not only between existing and new assets, but also between existing assets which have already completed their useful life and existing assets which are yet to complete their useful life.

Further, it would also impact the investments already made in the assets which are made relying upon the GFA Approach.

6.5.3 The Commission considering the views and suggestions of various stakeholders and the market conditions in the power sector, proposes that, the existing GFA approach of providing return on investments may be continued for the existing projects up to their original useful life. After completion of the original useful life of the respective projects, the Modified GFA Approach would be applicable. In case of new projects also, the Commission has presently considered application of the Modified GFA Approach after completion of original useful life. Furthermore, in case of the existing projects, which have completed their original useful life, the Modified GFA Approach shall be applied w.e.f 01.04.2019.

6.5.4 The Commission further clarifies that for the purpose of applying Modified GFA Approach, the capital structure, i.e. GFA, debt and equity as on cut-off date shall be considered and any additional capital expenditure after the cut-off date, including that for R&M shall be adjusted separately.

6.6 Proposed Provisions

6.6.1 In view of above, the Commission proposes clause (6) of the Regulation 17 in the draft notification issued on 14th December, 2018. Relevant Regulation is reproduced below.

"17. Debt-Equity Ratio:

……

(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."

7 Debt-Equity Ratio

7.1 Background

7.1.1 Financing plan of the project plays a predominant role in the determination of tariff. The Commission, since the 2004 Tariff Regulations has been consistently notifying debt-equity ratio as 70:30, for projects having COD on or after 1.4.2004. Further, if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% is treated as normative loan. For projects commissioned prior to 1.4.2004, the Debt-Equity ratio was kept as per Commission's decision in the respective tariff periods. Regarding, additional capital expenditure, the 2004 Tariff Regulations permitted equity component higher than 30%, with Commission's approval. However, the Commission w.e.f. its 2009 Tariff Regulations simplified the Debt: Equity provisions and specified the uniform debt-equity ratio of 70:30 for all the power projects i.e., whether it is initial project cost, additional capital expenditure or renovation & modernisation case.

7.1.2 However, the Commission has always rendered a free hand to the investors to optimise their project investment plan in the way they deem fit. Therefore, there is no restriction on equity investment even beyond 30% of the project cost. Its only for the purpose of tariff determination that, the equity deployed exceeding 30% of the project cost, if any, is considered as normative loan, which is allowed to be served at weighted average rate of interest of the actual loan taken for the project. However, if equity deployed is less than 30%, the actual debt-equity ratio will be considered for determination of tariff.

7.1.3 Further, in 2014 Tariff Regulations, in order to provide regulatory certainty as well as to make debt-equity ratio currency neutral, the Commission introduced a provision to the effect that equity invested in foreign currency should be designated in Indian rupees on the date of investment.

7.2 Existing Provision of Tariff Regulations, 2014

7.2.1 The existing 2014 Tariff Regulations consists of the following provision regarding Debt-Equity Ratio:

19. Debt-Equity Ratio: *(1) For a project declared under commercial operation on* *or after 1.4.2014, the debt-equity ratio would be considered as 70:30 as on COD. If the 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 licensee shall submit the resolution of the Board of the company or approval from Cabinet Committee on Economic Affairs (CCEA) regarding infusion of fund 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 1.4.2014, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2014 shall be considered.

(4) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2014, but where debt-equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2014, the Commission shall approve the debt-equity ratio based on actual information provided by the generating company or the transmission licensee as the case may be.

(5) Any expenditure incurred or projected to be incurred on or after 1.4.2014 as may be admitted 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.

7.3 Issues discussed in the Consultation Paper

7.3.1 The Consultation paper summarised the following issues:

"The capital cost for generation and transmission projects Commissioned after 1.4.2019 is considered to be financed through a debt-equity ratio of 70:30. Further, it is provided that if the actual equity deployed is more than 30% of the capital cost, the equity in excess of 30% shall be treated as normative loan whereas if the equity deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff. The above provision in Tariff Regulations is consistent with the principles laid down in the Revised Tariff Policy 2016.

Some of the utilities in private sector operate with a very high financial leverage. Also, it is observed that financial institutions are willing to extend finance up to debt- equity ratio of 80:20 depending on the credit appraisal of the utilities. When demand for capacity addition is low, maintaining debt-equity of 70:30 may need review.

Further, for some of the old plants, the equity base has been maintained beyond 30% (up to 50%) for the purpose of fixed return to enable the developer to generate internal resource for further capacity addition. In view of availability of sufficient capacity in the market, there is a need for review of the same.

Options for Regulatory framework

For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved."

7.4 Stakeholders' Response

7.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions

a) KERC has supported the suggestion made in the Consultation Paper.

b) All the Central sector stakeholders have submitted that normative debt to equity ratio should not be modified to 80:20.

c) Stakeholders submitted that as the investment decision has been taken considering viability of project based on extant regulations, the debt-equity ratio of existing and under construction projects should not be altered as this would adversely impact the cash flow and may lead to stress for under construction projects.

d) Many State level stakeholders have agreed to the proposal to modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved, in order reduce the burden of Return on Equity on the Consumers

e) Few State level stakeholders have submitted that the Commission may consider the normative debt-equity ratio at 80:20 (equity at 20% or actual whichever is lower).

f) Few of the State generating companies have supported the proposal with regard to equity base of the old plants. Further, it has been submitted that RoE shall be limited on equity up to 30% of the project cost for new generating stations.

g) One of the transmission licensee has supported the proposal to modify the normative debt-equity ratio of 80:20. But debt-equity ratio should be maintained at 70:30 for smaller utilities as SERC are normally guided by the CERC Regulations.

h) Few State level stakeholders have submitted that the present system of 70:30 should be continued.

i) Many beneficiaries have submitted that debt-equity ratio of 80:20 shall be beneficial to end users and should be adopted.

j) Few beneficiaries have submitted that present system of debt-equity ratio of 70:30 should be continued.

k) Most of the Private stakeholders have submitted that the normative debt-equity ratio for existing as well as new projects should be retained as 70:30 since the Tariff Policy, 2016 mandate debt-equity ratio of 70:30.

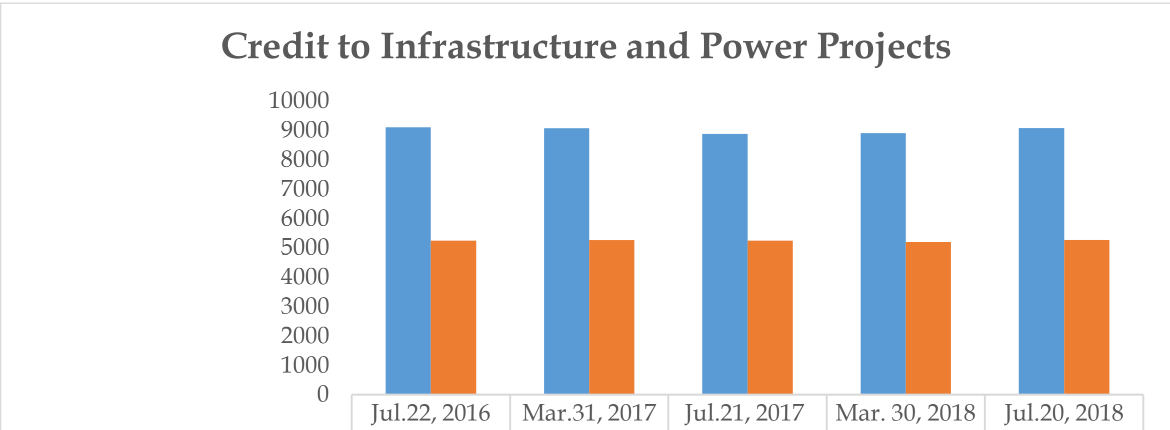
l) Many organizations have submitted that the present practice of debt-equity ratio of 70:30 may be continued.

m) Some organizations and individuals have suggested that the debt-equity ratio of 80:20 may even be considered for the existing plants, as most generating companies and transmission sector under cost plus mechanism are Government owned companies and there is no risk involved. This would make their tariff competitive vis-a-vis tariff determined by bidding process and thus would be in the interest of consumers.

7.5 Commission's Proposal

7.5.1 Considering the responses and suggestions, the Commission is of the view that in so far as the existing projects are concerned, the investors have made investments on the basis of the provisions of the then existing Tariff Regulations and any change in the debt-equity ratio of such projects would lead to regulatory uncertainty. Further, the Tariff Policy, 2016 provides for a debt-equity ratio of 70:30 for financing of future projects.

7.5.2 An analysis of the Banks' credit to Infrastructure and Power Sector is worth looking.



	Jul.22, 2016	Mar.31, 2017	Jul.21, 2017	Mar. 30, 2018	Jul.20, 2018
Infrastructure (Rs Billion)	9101.27	9063.94	8884.38	8909.37	9077.0294
Power (Rs Billion)	5245.12	5253.93	5246.86	5196.19	5268.4787

Source: RBI Database

Figure 6: Banks' Credit to Infrastructure and Power Projects

7.5.3 It may be observed from the above chart that there has been significant bank credit to infrastructure projects and the power sector shares a major contribution of the bank credit. The proposal for modifying debt-equity ratio to 80:20 from the existing norm of 70:30 may not be sustainable as financial institutions/banks may not be willing to finance such high proportion of the capital cost of a project, particularly, in the wake of rising bad loans and NPA from the sector. Further, any increase in leverage to the power sector utilities, would result in increasing the exposure of beneficiaries to the risk of excessive volatility of interest rates.

7.5.4 Higher debt will increase IDC and interest cost burden and consequentially the cost of project resulting in higher cost of power. The rate of depreciation may have to be enhanced to avoid imbalance between the depreciation allowed and debt repayment obligation. Changing debt-equity ratio to 80:20 will also lead to higher dependency on loan and will increase interest cost.

7.5.5 In case of delay in commissioning and non-recovery of fixed cost for any reason, the project will face increased risk of turning into NPA.. Further, increase in the debt component may lead to increase in the interest rates, which may have further impact on tariff rates and Debt Service Coverage Ratio (DSCR). Therefore, the Commission proposes to continue with the existing debt-equity ratio of 70:30 in the Draft Tariff Regulations on account of its wider acceptance both by the investors and the financial institutions.

7.6 Proposed Provisions

7.6.1 In view of above, the Commission proposes Regulation 17 in the Draft Tariff Regulations which is reproduced as below.

"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 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 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 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."

8 Return on Investment

8.1 Background

8.1.1 During the 2004 Tariff Regulations, after considering the comments from stakeholders, the Commission concluded that the Return on Capital Employed (RoCE) is a better approach and the changeover to RoCE could be considered after the interest rates stabilize and benchmarking of debt-equity ratio is achieved. Thus, the Commission decided to continue with the existing RoE approach.

8.1.2 In the 2009 Tariff Regulations also, the Commission continued with RoE approach due to frequent interest rate fluctuation and state of development of debt market in India since, it was difficult to have a projection of a firm normative interest rate for the purpose of arriving at return on capital employed. Further, implementation of RoCE approach would raise several issues as it requires computation of annual Weighted Average Cost of Capital (WACC) due to progressive change and reduction in capital employed.

8.1.3 During the course of framing the 2014 Tariff Regulations, the Commission again evaluated the merits of RoCE and RoE approaches. The Commission observed that the implementation of RoCE approach requires benchmarking of cost of debt and debt:equity ratio. The Commission after examining the depth of Indian Corporate Bond Market and comparison of Corporate Bond to GDP ratio of India with other major Asian economies, concluded that the Indian Corporate Bond market is still in its nascent stage. Therefore, the Commission decided that it would not be desirable to switch to RoCE approach and decided to continue with the existing RoE approach.

8.2 Issues discussed in the Consultation Paper

8.2.1 The Consultation Paper had summarised the following issues.

"17. Return on Investment

17.1 In a cost-plus tariff setting approach, the utilities are allowed to earn a reasonable return on their investments besides recovering all other costs incurred through tariff. The return on investment is allowed as a compensation to the investors for assuming the investment related risks. It is based on opportunity cost principle and risk premium. Under the concept of cost of capital approach, the rate of return is allowed on the basis of different components viz. Return on Equity, cost of debt etc. catering to the different types of investors.

17.2 Section 61 (d) of the Electricity Act, 2003 and Para 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for determination of rate of return. These have mandated to maintain a balance between the interests of consumers and need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and prevalent cost of capital. Further, it should lead to generation of reasonable surplus and attract investment for the growth of the sector. As per the Tariff Policy, the Commission may adopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors.

17.3 Over a period of time, allowing fixed rate of Return on Equity has evolved as an acceptable approach and the same has been followed by most of the State Electricity Regulatory Commissions. The RoE approach has been widely accepted by investors in the sector. The large scale investment in the power sector is attributable to the approach of fixed rate of return. The Commission had compared both the approaches viz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided to continue with RoE approach with the following observations in the Explanatory Memorandum;

"As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each Control Period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues faced by Developers in sector such as fuel shortages etc., it appears that it is not the desirable to switch to RoCE approach and thus the Commission proposes to continue with the RoE approach for next Tariff Period. Further most of the stakeholders suggested continuing the existing RoE approach."

8.3 Stakeholders' Response

8.3.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) KERC submitted that the present RoE approach may be continued to encourage investment in the sector.

b) Few Central Generating Companies submitted that adopting RoCE regime would imply reduction in returns, which would hamper future investments into the sector.

c) Few Central sector Generating Companies have submitted that under

RoCE approach, return once fixed may result in under recovery due to elements like floating rate of interest on loans, foreign exchange rate variation and similar other variables.

d) A transmission licensee has submitted that existing assets need to be protected as the investment decisions, debt raising etc. are based on the current Tariff Regulations. In case of a shift to RoCE, an equivalent rate of return may be computed by the regulator to maintain the same rate of return under the existing RoE.

e) Some State sector companies have submitted that position prevailing while deciding 2014 Tariff Regulations is still valid as there is shortage of fuel, and financial health of generation companies is not good due to default in payment by beneficiaries. Therefore, method of RoE should be continued

f) One of the distribution licensee has submitted that in Delhi, RoCE Approach based on NFA is already in place where Generating companies, transmission licensees and distribution licensees gets return linked to the actual funds as on date basis.

g) Few Discoms have suggested that Fixed rate of Return on Equity is an acceptable approach and has been followed by most of the State Electricity Regulatory Commissions. It is a tried and tested method and hence, easily understood by all stakeholders. Therefore, the fixed rate approach (RoE Approach) should be continued with modified GFA.

h) Some private sector stakeholders have suggested that benchmarking of RoCE is difficult in current unstable financial markets. Any variation in cost of debt would add to developer's risk.

8.4 Commission's Proposal

8.4.1 The Commission understands that implementation of RoCE approach requires benchmarking of the cost of debt and debt-equity ratio. The debt requirement of power sector is huge and the same cannot be catered to only by domestic banks and domestic capital market and rather also needs investment from international financial institutions. Further, recently significant volatility has been witnessed in the interest rates.

8.4.2 In case the relaxed benchmark interest rates are used for all entities, it may result in windfall gains for some and substantial loss for the beneficiaries and if stringent rate is used as benchmark, many existing entities may incur losses.

8.4.3 Tariff is determined on multiyear principles. Therefore, it is important to ensure certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rates and shallow debt market, it may not be the appropriate time to switch to RoI approach. Thus, the Commission proposes to continue with the existing RoE approach for next Tariff Period.

8.4.4 Further, as already discussed in a previous Chapter, ,the Commission has proposed to adopt the Modified GFA Approach after completion of original useful life of the asset.

8.5 Proposed Provisions

8.5.1 The Commission has decided to continue with Return on Equity approach in which the returns are provided on the normative equity base, i.e., 30% or actual equity deployed, whichever is lower. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan and where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff. The interest on loan is provided separately duly considering the loan repayment equivalent to depreciation and the weighted average rate of interest calculated on the basis of actual loan portfolio at the beginning of each year applicable to the project.

9 Tariff Determination for Part Capacity and / or Expansion of Capacity

9.1 Background

9.1.1 In some of the generating stations, the entire capacity is not tied up under section 62 of the Act. In such generating stations, only partial capacity is tied under section 62 under long-term power purchase agreements and the remaining capacity is either tied up under section 63 of the Act or being sold at the energy market. Further, under provisions of the Tariff Policy, 2016, the expansion of existing generation capacity or existing projects, where the tariff is required to be determined under section 62 (not exceeding one time expansion upto 100% in case of a private developer), there may be instances of part capacity being installed under section 63 of the Act also. In these conditions, under the existing 2014 Tariff Regulations, the tariff is determined with reference to the capital cost of the entire project. However, such tariff is applicable only corresponding to the capacity contracted for supply to the beneficiaries.

9.2 Existing Provision

6. <u>Tariff determination</u>

…….

(5) Where only a part of the generation capacity of a generating station is tied up for supplying power to the beneficiaries through long term power purchase agreement and the balance part of the generation capacity have not been tied up for supplying power to the beneficiaries, the tariff of the generating station shall be determined with reference to the capital cost of the entire project, but the tariff so determined shall be applicable corresponding to the capacity contracted for supply to the beneficiaries.

9.3 Issues discussed in the Consultation Paper

9.3.1 The Consultation Paper had summarised the following issues..

Components of Tariff

9.1 Unlike the Central Generating Stations, for privately owned generating stations, not all the generating capacity may have tied up power purchase agreements. In such case, part capacity may have been tied up under Section 63 and/or Section 62 of the Act and balance may have remained as merchant capacity. 9.2 Section 62 of the Act provides that the Appropriate Commission shall determine the tariff for (a) supply of electricity by a generating company to a distribution Licensee, (b) transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section 61(b) of the Act provides that the Appropriate Commission shall specify the terms and conditions of tariff for generation, transmission, distribution and supply of electricity are conducted on commercial principles. The commercial principles inter-alia emphasize the risk allocation through contractual arrangement such as power purchase agreement in case of generation and transmission service agreement or long term access agreement in case of transmission service.

Options for Regulatory Framework

9.3 The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be.

Comments/ Suggestions

9.4 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

9.4 Stakeholders' Response

9.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) KERC supported the proposal that the tariff of the generating station for entire capacity should be determined but recovery may be restricted to the extent of power purchase agreement on pro-rata basis. The balance capacity could be merchant capacity or tied up under Section 63.

b) Few of the Central Generating Companies submitted that the annual fixed charges should be determined for the entire capacity so that there is no uncertainty for developer's investment and also regulatory risk. However, the recovery of annual charges may be restricted on pro-rata basis in case of signed power purchase agreements and balance capacity should be treated as merchant capacity for trading through energy exchange. Additionally, in case of merchant trading, the generating company may be allowed to sell its power at higher/lower rates depending upon the energy market scenario, without obtaining any consent from the regulator.

c) Some of the Stakeholders submitted that Commission may continue to determine the Annual Fixed Charges and Energy Charges for entire capacity under Section 62. However recovery of AFC may be restricted to the extent of power purchase agreement on pro-rata basis. Balance capacity may be merchant capacity tied up either under Section 63 or under Section 62. Appropriate provision may be incorporated to enable an existing beneficiary or any distribution licensee willing to purchase under short term at the tariff determined under Section 62 so that it may do so with the approval of the appropriate State Electricity Regulatory Commission, appropriate provision.

d) Some distribution licensee have suggested that the recovery of tariff to the extent of PPA on pro-rata basis and selling the balance on merchant capacity or under Section 63 shall contribute towards optimization of cost. However, the same should be implemented on quarterly basis or monthly basis so as to provide flexibility to Discoms to block capacity and schedule power by factoring in seasonal variations.

e) Few Discoms suggested that in the case of privately owned generating station with part of the capacity covered under Section 63 (competitive bidding), part of the capacity under merchant power and a part of capacity sold to a distribution company through regulated tariff, the regulated tariff should not be determined considering the entire plant and then deducing for the part of the plant. It is better to benchmark the capital cost of the entire plant based on the competitive bidding price as the ceiling and then the tariff for the regulated part should be determined and regulated tariff should be lower than the price discovered through competitive bidding if Government allocates captive coal mine (25 years PPA with Discom).

f) Some private sector stakeholders and individuals observed that determination of Tariff of the entire generating station might impact the tariff conditions of other PPAs entered into by the generator.

9.5 Commission's Proposal

9.5.1 The Commission understands that in case where only part capacity of the generating station is tied up under section 62, it is difficult to segregate and determine the capital cost and hence the tariff for that part capacity of the project. Therefore, the Commission has to determine the capital cost and the tariff for the entire capacity. However, the recovery from the beneficiaries is restricted in proportion to the part capacity covered under section 62 of the Act.

9.5.2 In the Draft Tariff Regulations, the Commission has proposed to clearly identify and segregate unit-wise capacities under section 62 and section 63 of the Act. In case, where clear segregation of the generating units in terms of the capacities tied up under section 62 and section 63 is possible, the Commission has proposed to determine the tariff only for the identified unit of the generating station from which capacities are tied up under section 62 of the Act, instead of the entire generating station. Only in case where the part capacity is not identifiable with the specific unit or where only part capacity of a unit is tied up under section 62 of the Act, the Commission shall determine the capital cost and hence the tariff for the entire generating station.

9.5.3 The Commission has also proposed to determine the tariff of the expanded capacity of an existing generating station, in accordance with the provisions of the Draft Tariff Regulations, to the extent it is required to be determined under section 62 of the Act. With a view to ensure that such expansion of the generating capacity results in a gain to the beneficiaries, the Commission has provided that, the common infrastructure of the existing generating station shall be utilized for the expanded capacity and the benefit of new technology in the expanded capacity shall be extended to the existing capacity of the projects. Accordingly, the expanded capacity shall get the benefit of already existing common infrastructure, while the existing capacity shall get the benefit of the new technology resulting in enhancing the operational efficiency of the generating station as a whole.

9.6 Proposed Provisions

9.6.1 In view of above, the Commission proposes Regulation 8 in the Draft Tariff Regulations which is reproduced below.

"8. Tariff determination

………

(2) Where only a part of the generation capacity of a generating station is tied up for supplying power to the beneficiaries through long term power purchase agreement, the units for such part capacity shall be clearly identified and in such cases, the tariff shall be determined for such identified capacity. Where the unit(s) corresponding to such part capacity cannot be identified, the tariff of the generating station may be determined with reference to the capital cost of the entire project, but tariff so determined shall be applicable corresponding to the part capacity contracted for supply to the beneficiaries;

(3) In case of expansion of existing generating station, the tariff shall be determined for the expanded capacity in accordance with these regulations:

Provided that the common infrastructure of existing generating station, shall be utilized for the expanded capacity and the benefit of new technology in the expanded capacity shall be extended to the existing capacity."

10 Tariff Mechanism for Pollution Control System

10.1 Background

10.1.1 The Ministry of Environment, Forest & Climate Change (MoEFCC) has notified the revised standards for coal-based thermal power plants (TPPs) in the country. These standards are proposed to be implemented in a phased manner. Thermal power plants are categorised into 3 categories, namely those:- (i) Installed before 31st December, 2003 (ii) installed after 2003 and upto 31st December, 2016 and (iii) installed after 31st December, 2016. As per the new Environment norms notified by MoEFCC, the TPPs would be required to install or upgrade various emission control systems like Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. to meet the revised standards.

10.2 Existing Norms

10.2.1 Presently there is no existing provision pertaining to emission control systems.

10.3 Issues discussed in the Consultation Paper

10.3.1 The Consultation Paper had summarised the following issues.

"Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)

33.1 As per the new Environment norms notified by Ministry of Environment, Forest and Climate Change, the TPPs would be required to install or upgrade various emission control systems like Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. to meet the revised standards. Recovery of the investment made during operation period in the form of additional capitalization through redesigning or retrofitting of plant and related operational costs require a mechanism in the tariff regulations.

33.2 Several generating companies have filed petition for approval of additional capital expenditure under "change in law" for complying the revised standards of emission for thermal power projects. CEA may be required to specify and benchmark appropriate technology and costing norms, apart from preparing phasing plan for shutdown during installation of emission related retrofits/ equipment. The generating companies would be required to select suitable technology at competitive rates through the process of transparent competitive bidding to minimize the impact on tariff in the power supply agreement.

Option for Regulatory framework

33.3 There is likelihood of significant impact on tariff on account of compliance with these norms. Supplementary tariff could be determined considering the followings.

a) The principle of bringing the generator to the same economic condition if it is considered as change in Law.

b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period;

c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years.

d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipment.

Comments/ Suggestions

Possibility of reducing funding cost through suitable change in debt:equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt;

"Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the remaining period;

As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both."

10.4 Stakeholders' Response

10.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders had submitted following comments/suggestions.

a) Few of the Central Sector Generating Companies submitted that, such investment may be treated as additional capitalization on account of change in law and serviced in tariff. Providing returns at the cost of debt on the equity portion is neither equitable nor fair as it would not provide any compensation to the additional risk of environmental compliance borne by the generators. If equity portion is also serviced at cost of debt, any under recovery would lead to situation where repayment of loan may be affected. Installation of such system is mandatory and a statutory requirement. Therefore, incremental impact on the Auxiliary consumption or other operational parameters should be considered as uncontrollable and may be passed on to the beneficiaries.

b) Some of the stakeholders submitted that, when the PLF for Thermal Generating Stations will be around 60%, the question arises whether the level of emission of pollutants will have a downward trend and may remain within the allowable emission levels as mandated by MoEFCC. Without ascertaining the same, it would not be prudent to install the Emission Control Systems, which will burden the consumers financially. For those TPPs, where the pollution levels are beyond the allowable level of emissions, the Emission Control Systems with proven technology and performance be procured through competitive bidding. The cost of the Emission Control Systems should be met from Power System Development Fund (PSDF) or Clean Energy Fund.

c) Some Discoms have suggested that, the principle laid down by the Hon'ble Supreme Court that "Polluter Pays" should be implemented. The impact on Tariff is very significant. As per industries estimates, the impact of implementation of norms is Rs. 0.30/kwh to Rs. 0.60/kwh depending upon the plant specifications. Also, there are constraints on timely implementation of retrofitting for the generating stations. As per CEA, the retro-fitting is required to be done by 2022. Hence, it is pre-mature to load such a huge impact on the consumers' tariffs. As the implementation of the notification will be beyond the control period 2019-24, the Commission may consider the impact of such cost while truing-up only.

d) Few Discoms have suggested that since this capital expenditure will create huge financial impact on Discoms a regulatory intervention of reducing the impact in tariff may be taken. It is suggested that RoE for such capital may be limited to interest rate of loan, debt-equity ratio may be limited to 80:20, depreciation and interest on loan obligation for the capex may be extended to the entire useful life of the project.

e) Some of the private sector stakeholders have suggested that the Commission may introduce norms for recovery of capital and operational expenditure including additional auxiliary consumption in consultation with the Central Electricity Authority. The same norms may be made applicable to projects under Section 63 as well similar to the provisions made for low PLF in the Grid Code. Since revised emission standards have already been declared as "change in law" by the Ministry of Power, actual cost incurred may be allowed as a pass-through. In addition, the costs associated with disposal of by-product of FGD system and cost incurred during the installation period of the FGD system in the form of loss of capacity charges due to reduced availability of the plant is substantial which should also be considered for evaluation of the impact of FGD system on tariff.

10.5 Commission's Proposal

10.5.1 The Commission has proposed to include facilitative provisions at appropriate places in the Draft Tariff Regulations to provide clarity to the generating companies and the beneficiaries that the capital expenditure incurred or to be incurred in respect of meeting the revised emission standards shall form part of the capital cost of the generating station.

10.5.2 The Commission is aware of the fact that the additional capital expenditure on account of setting up the pollution control facilities to meet the revised emission standards in the generating stations will result in increase in the capacity charge of the generating station. Further, the pollution control facilities shall also require additional recurring expenses in the form of reagent, consumables, additional O&M expenses and also result in additional impact on the operating norms, specifically the auxiliary energy consumption of the generating station. Thus, the impact will result in increase in capacity charges as well as energy charges of the generating stations. The generating stations which set up the pollution control facilities for meeting the revised emission standards earlier will be at competitive disadvantage in terms of landed cost of power to the beneficiaries, as compared to the generating stations which may set up such pollution control facilities for meeting the revised emission standards at a later stage.

10.5.3 Therefore, with a view to provide level playing field to all generating stations in the transition phase, till the time the revised emission standards are met by all the generating stations, the Commission has proposed that the tariff on account of additional capital expenditure incurred for setting up the pollution control facilities shall be determined separately as supplementary tariff. The Commission has proposed to include suitable provisions at relevant sections/chapters of the Draft Tariff Regulations to provide the requisite clarity required for regulatory approval process w.r.t to the additional capital expenditure envisaged for setting up the pollution control facilities to meet the revised emission standards. Further, the Commission has also proposed that the detailed methodology for determination of supplementary energy charges shall be notified separately.

10.6 Proposed Provisions

10.6.1 In view of above, the Commission proposes provisions in Regulation 8, 9, 14, 16, 18 and 29 in the Draft Tariff Regulations which is reproduced below:-

"8. Tariff determination

………

(4) Assets installed for implementation of the revised emission standards shall form part of the existing generation project and tariff thereof shall be determined separately on submission of the completion certificate by the Board of the generating company.

9. Application for determination of tariff

………

(3) In case of emission control system required to be installed in existing generating station as per revised emission standards, the application shall be made for determination of supplementary tariff (fixed charges or variable charge or both) based on the actual capital expenditure duly certified by the Auditor;

14. Components of tariff

………

(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 Commission separately;

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 consist of the following cost:

(a) Landed Fuel Cost of primary fuel; and

(b) Cost of secondary fuel oil consumption:

………

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;

18. Capital Cost:

………

(2) The Capital cost of a new project shall include the following:

……..

(l) Expenditure on account of emission control system necessary to meet the applicable emission standards of notified by Government;

29. Additional Capitalization on account of Revised Emission Standards: (1) A generating company requiring to incur additional capital expenditure in the existing generating station for compliance of the applicable revised emissions standards shall share its proposal with the beneficiaries and file a petition for approval for undertaking such additional capitalization;

(2) The proposal under clause (1) above shall contain details of proposed technology as specified by the Central Electricity Authority, scope of the work, phasing of expenditure, schedule of completion, estimated completion cost including foreign exchange component, if any, detailed computation of indicative impact on tariff to the beneficiaries, and any other information considered to be relevant by the generating company;

(3) Where the generating company makes an application for approval of additional capital expenditure on account of implementation of Emission Control Standards, the Commission may grant approval after due consideration of the reasonableness of the cost estimates, financing plan, schedule of completion, interest during construction, use of efficient technology, cost-benefit analysis, and such other factors as may be considered relevant by the Commission.

(4) After completion of the implementation of revised emission standards, the generating company shall file a petition for determination of tariff. Any expenditure incurred or projected to be incurred and admitted by the Commission after prudence check based on reasonableness of the cost and impact on operational parameters shall form the basis of determination of tariff."

11 Return on Equity (RoE)

11.1 Background

11.1.1 The Commission had specified a post-tax RoE rate of 16% based on the recommendations of the study commissioned to review the cost of capital for the Tariff Period 2001-04 and reduced post-tax RoE rate to 14% for the Tariff Period 2004-09. However, for 2009 Tariff Regulations, the Commission decided to revise the RoE to 15.5% on post-tax basis considering the rise in the PLR of the public sector banks, 10-year G-Sec rates then, and other macro-economic conditions and to help the entities to build up sufficient internal accruals for investment in capacity addition. For storage type generating stations, including pumped storage hydro stations and run of river generating station with pondage, the post-tax RoE was increased to 16.5%. The Commission in its 2009 Tariff Regulations, provided additional Return on Equity at the rate of 0.5% to the projects that are completed within the specified time. Tariff Policy, 2016 stipulates that while laying down rate of return, the Commission shall maintain a balance between the interests of the consumers and the need for investments. In view of this, the Central Commission notifies, from time to time, the rate of RoE for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital and the same is followed by the SERCs. The rate of return notified by CERC for transmission is also adopted by the SERCs for distribution with appropriate modification taking into account the risks involved in the distribution sector.

11.1.2 In case of equity, any cash resources available to the company from its share premium account or from its internal resources that are used to meet the equity commitments of the project are treated as equity subject to limitation of the specified debt-equity ratio.

11.1.3 The Commission for the Tariff Period 2001-04 and 2004-09 specified post-tax Return on Equity and allowed income tax, in respect of income from core businesses only, as pass through to be recovered separately on actual basis. However, in 2009 Tariff Regulations, considering the views of various stakeholders, the Commission allowed pre-tax Return on Equity to the utilities.

11.2 Existing Provisions of the 2014 Tariff Regulations

*"**24. Return on Equity**: (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 19.*

(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, 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. in case of projects commissioned on or after 1st April, 2014, an additional return of **0.50 %** shall be allowed, if such projects are completed within the timeline specified in **Appendix-I**:*
- *ii. the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever:*
- *iii. additional RoE of 0.50% may be allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element will benefit the system operation in the regional/national grid:*
- *iv. the rate of return of a new project shall be reduced by 1% 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)/ Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system:*
- *v. as and when any of the above requirements are found lacking in a generating station based on the report submitted by the respective RLDC, RoE shall be reduced by 1% for the period for which the deficiency continues:*
- *vi. additional RoE shall not be admissible for transmission line having length of less than 50 kilometers.*

25. Tax on Return on Equity:

(1) The base rate of return on equity as allowed by the Commission under Regulation 24 shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax income on other income stream (i.e., income of non generation or non transmission business, as the case may be) shall not

be considered for the calculation of "effective tax rate".

(2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where "t" is the effective tax rate in accordance with Clause (1) of this regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration.-

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 20.96% including surcharge and cess:

Rate of return on equity = 15.50/(1-0.2096) = 19.610%

(ii) In case of generating company or the transmission licensee paying normal corporate tax including surcharge and cess:

(a) Estimated Gross Income from generation or transmission business for FY 2014-15 is Rs 1000 crore.

(b) Estimated Advance Tax for the year on above is Rs 240 crore.

(c) Effective Tax Rate for the year 2014-15 = Rs 240 Crore/Rs 1000 Crore = 24%

(d) Rate of return on equity = 15.50/ (1-0.24) = 20.395%

(3) The generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2014-15 to 2018-19 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the transmission licensee as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term transmission customers/DICs as the case may be on year to year basis."

11.3 Issues discussed in the Consultation Paper

"18. Rate of Return on Equity

18.1 Return on equity is the return allowed to the ordinary shareholders on their equity investment in generation/transmission projects. To ensure that it is fair to both the investors and the consumers, the return allowed should be commensurate with the returns available from alternate investment opportunities having comparable risk. Different models viz. Discounted Cash Flows (DCF), Risk Premium Model (RPM), Capital Asset Pricing Model (CAPM) etc. are available for estimation of cost of equity/RoE. However, the Commission has been largely depending on the CAPM model for arriving at RoE during previous tariff periods.

18.2 The Commission had specified a post tax RoE of 16% and 14% respectively for the tariff periods 2001-04 and 2004-09 respectively. For the tariff period 2009-14, the Commission had specified a post tax base rate of 15.5% and allowed it to be grossed up by the applicable tax rate. An incentive of 0.5% was also allowed for the generation/transmission projects completed within the prescribed timeline. For the tariff period 2014-19, the Commission continued with the post tax base rate of 15.5% as allowed for 2009-14 tariff period with an additional 1% RoE i.e. 16.5% allowed for storage type hydro generating stations.

18.3 As per the present regulatory framework, the additional return on equity is allowed for all the units or the transmission elements irrespective of their size or length of line if such assets have been commissioned as per the timeline specified by the Commission. The timeline applied is same irrespective of size of the project-length of line in transmission project or capacity of the unit in generation projects.

18.4 Further, the additional return of 0.5% is given to incentivize the project developer for timely completion. However, there is no disincentive for delay in completion of the project.

18.5 Following key trends have been observed during recent times: -

- The capacity addition (as per CEA report) achieved from conventional sources during the plan period 2012-2017 exceeded the target with more than 50% of the capacity addition coming from the private sector. Besides, there has been a rapid increase in renewable energy capacity addition.
- The draft National Electricity Plan 2016 of CEA has indicated that there will be no need for additional non-renewable power plants till 2027 with

the commissioning of 50,025 MW of under construction coal based power plants and additional 1,00,000 MW renewable power capacity.

- The PLF of thermal power plant has come down steadily during last 4-5 years (as per CEA report), mainly due to higher capacity additions, low demand growth and increase availability of renewable energy.
- As per RBI database, notwithstanding the recent increase in the yield for 10 year benchmark government securities, the overall interest rate has shown a declining trend during the period 2014-19. The yield on 10 year benchmark Government Bond has come down to 7-7.5% during 2018 as compared to 8-8.5% during 2014. The RBI repo rate, interbank rate and SBI base rate have also come down during this period. With better control over inflation, the interest rates are expected to remain low and stable over short & medium term.
- The Tariff Policy has mandated the distribution licensees to procure their future requirement of power through Tariff Based Competitive Bidding. The market forces are likely to exert downward pressure on the IRR of the new projects.

Options for Regulatory Framework

18.6 According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favors reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects.

18.7 (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;

(b) Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects;

(c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects;

(d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project;

(e) Continue with pre-tax return on equity or switch to post tax Return on equity;

(f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation;

(g) Reduction of return on equity in case of delay of the project;"

11.4 Stakeholders' Response

11.4.1 The Consultation Paper had sought view from the stakeholders as to whether there is a need to review the existing level of return on equity and also if there was a need for differential rate of return for generation projects (hydro and thermal) and transmission projects. The stakeholders had given following comments and suggestions.

a) KERC suggested, considering the present borrowing rate, an RoE of 14 % instead of current 15.5%.

b) Some of the Central sector hydro generating companies submitted that the existing Rate on Equity is proving to be inadequate for hydropower generation business in India. RoE should either be enhanced or at least retained at the level of 16.50% to protect the power sector utilities against business and market risks. Further pondage/storage type hydro projects should be given additional return. There should not be any reduction of return on equity in case of delay, since as in case of delay the developer's effective rate of return is automatically reduced.

c) Few Central sector thermal generating companies submitted that thermal power stations face significant construction & operational risks, which are unique and are not faced by other segments in power sector. The risks include the long gestation period of 7 to 8 years during which no return is available. There is a case for thermal power generators to be compensated for the higher operational risks by increasing the RoE by at least 6% (15.5%+6%).

d) One of the stakeholders submitted that it would be inappropriate to equate return of all infrastructure projects since they have different gestation periods and risks (14% RoE for solar equates to 19% for thermal generation sector). Accordingly, there is a case for increase in RoE.

e) A transmission licensee submitted that, the CERC has allowed a rate of return of 14% for renewable projects. Considering a construction period of 1 year, in order to match the effective rate of return for a renewable project, the rate of return for transmission licensee works out to be 16.81%. From CAPM method, the expected return works out to be 19.18%, much more than the existing return of 15.50%. Determining an equitable pre-tax rate applicable to all assets (each of which would have different tax benefits and tax burden, and in case of generation assets, different beneficiaries), would be a challenge and therefore, the current system may be continued.

f) Some of the State sector generating companies have submitted that, RoE for all plants, new and old must remain same i.e. 15.5% as per the 2014 Tariff Regulations.

g) One of the stakeholder submitted that, any reduction in RoE will have a negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. To encourage investment in new hydro projects, the rate of RoE may please be kept higher than Thermal project to attract new investors.

h) Few Discoms suggested that, there should be different rates of ROE for generating companies and transmission licensees depending upon the risk profile. Even between thermal and hydro, there should be different ROE. Since there is more risk factor in Generation, ROE should be higher for generation segment compared with transmission segment.

i) One of the Discom submitted that the need for higher rate of RoE required may be reviewed in the present regime of low cost of financing and huge generation addition in the Country. It is also submitted that pre-tax RoE basis will not motivate the generators/licensees to take efforts for reducing tax burden. Therefore, it is requested that post tax RoE with tax reimbursement on actual may be adopted in the new Regulations.

j) Few Discoms also submitted that in case of delay in commissioning (as per the targets set by Commission), there can be disincentive in RoE. Only those works that relate to environmental norms, PAT scheme should be permitted beyond CoD and up to cut-off date without penalizing on 0.5% RoE. Further, penalty of 1% of RoE can be imposed in case of delay in commissioning of FGMO / RGMO, communication system etc. Rate of RoE should be reduced as risk free return (G-Sec) has come down.

k) Some private stakeholders suggested that the present RoE rate of 15.5% gives adequate premium. A higher RoE should be given to developer considering that there is no return given during gestation period.

l) One of the stakeholder submitted that proportion of stressed assets is at an all-time high and this infers that in current scenario as well, there are numerous risks associated with setting up of generating stations which may not be reflected in general market trend. The Govt. bond rates are increasing since past 1 year. The bond rates have risen from 6.46% in July'17 to 7.90% in July'18. The Commission should consider revising the return on equity upwards.

m) Few stakeholders also submitted that economic slowdown, change in interest rates and uncertainties w.r.t. land acquisition, etc. have led to an increase in the level of risks for the developers. Factors like construction period, risks associated with the projects and the need to incentivize new investment should determine project returns

11.5 Commission's Proposal

11.5.1 Clause (d) of Section 61 of the Act provides that the Commission while specifying the terms and conditions for determination of tariff, shall be guided by the principle of "*safeguarding of consumers interest and at the same time, recovery of cost of electricity in a reasonable manner*".

11.5.2 The Commission had adopted Capital Asset Pricing Model (CAPM) to determine the cost of equity as in the 2014 Tariff Regulations. This was done because it was felt that out of the various scientific models such as Dividend Growth Model/Discounted Cash Flow Model, Price/Earning Ratio Method, Risk Premium Approach and CAPM, the Commission observed that CAPM was more suitable for determining the cost of equity for investments in the Indian power sector. Further, CAPM is also the most popular and widely accepted method for determining the cost of equity. It is recognised that this model will not give the exact rate of return on equity, as it is based on the assumption of data which is taken as input. For e.g. market return data taken for 5 years, 10 years or more would give different rates for return on equity. Risk Free rate taken as Government/Sovereign Bonds yield for 1 years, 5 years or 10 years will also impact the rate of return on equity. However, the CAPM gives an approximate rate of return on equity, which can be used to take an informed decision on rate of return on equity.

11.5.3 The CAPM describes the relationship between the expected return and risk of investing in a security. It shows that the expected return on a security is equal to the risk-free return plus a risk premium, which is based on the beta of that security. CAPM can be summarized according to the following formula:

Required (or expected) Return = Risk Free Rate + (Market Return – Risk Free Rate) x Beta.

11.5.4 Though Government securities do not have a default risk, they are still susceptible to reinvestment risk and inflation risk. To eliminate reinvestment risk, zero coupon securities have been considered. However, inflation risk is still not effectively mitigated. Due to the lack of any better measure of risk free rate, the Commission has considered the yield on zero coupon Government securities as Risk Free rate. The Risk Free rate has been considered as average of the yield on 10-year government securities yield *(Source – RBI Notification)* for the period April, 2017 to March, 2018, i.e., 6.97% and for first quarter of FY 2018-19 is 7.76%. In the last 12 months or so, the 10-year government securities yield has been showing an increasing trajectory and has increased to 7.76%, after touching a 10 year low of 6.97% in FY 2017-18. The following graph shows the trend of 1- year government securities yield since 2001.

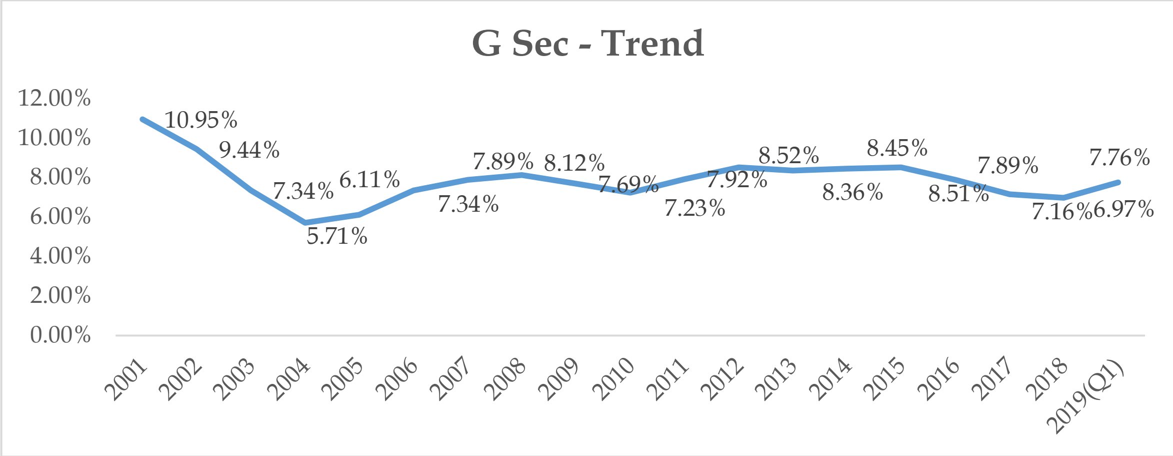


Figure 7: Ten-Year Government Securities Yield Trend

11.5.5 In order to compute the Market Risk Premium (Rm), the return expected by the market has been estimated by assuming the past returns provided by the equity market, as it mirrors the expectations of the investors. For determining the market return, the Commission has considered the returns provided by the BSE Sensex over the period from April 1992 to June 2018, as a proxy for the historical returns provided by the Indian equity market. The average annual growth rate of the BSE Sensex over the period 1992 – 2018 works out to around 14.52% as shown in the graph below.

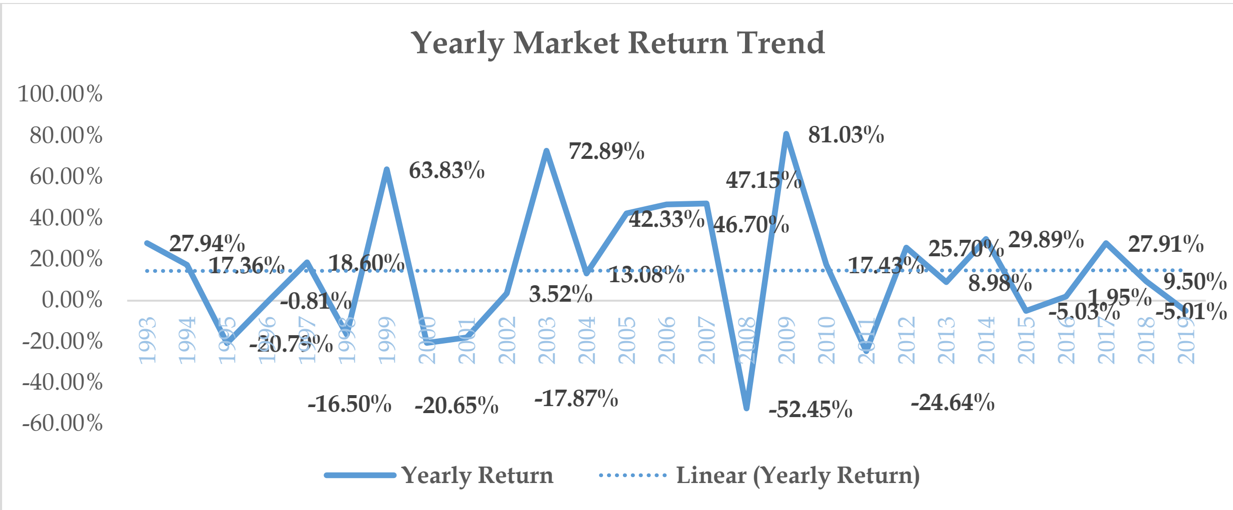


Figure 8: Yearly Market Return Trend

11.5.6 The electricity sector in India expanded mainly after 2001, when the number of players in the market increased. Many power companies have been listed from 2001 onwards. Therefore, it has been contemplated that the expected market return after 2001 is more representative. In order to compute the Market Risk Premium (Rm), the return expected by the market has been estimated by assuming the past returns provided by the equity market, as it mirrors the expectations of the investors. For determining the market return, the Commission has considered the returns provided by the BSE Sensex over the period from April 2001 to June 2019, as a proxy for the historical returns provided by the Indian equity market. The average annual growth rate of the BSE Sensex over the period of 2001–2019 (Q-1) works out to around 17.00% as shown in the graph below.

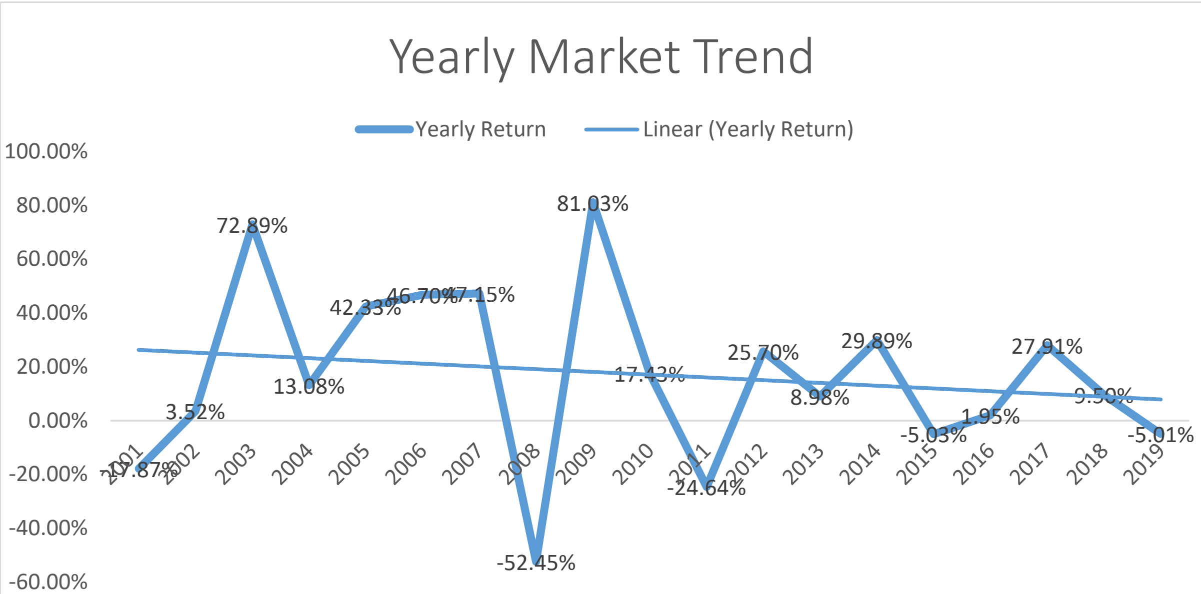


Figure 9: Yearly Market Return Trend

11.5.7 Beta is a measure of the volatility, or systematic risk, of a security or a portfolio in comparison to the market as a whole. For computing the Beta for CAPM formula, firstly the levered Beta is estimated for all major power sector companies in the business of power generation and transmission listed in the BSE. The overall market has a beta of 1.0, and individual stocks are ranked according to how much they deviate from the market. A stock that swings more than the market over time has a beta greater than 1.0. If a stock moves less than the market, the stock's beta is less than 1.0. High-beta stocks tend to be riskier but have the potential for higher returns; low-beta stocks pose less risk but typically yield lower returns. Unlevered Beta (i.e. Asset Beta) is the Beta of a company without the impact of debt. It is also known as the volatility of returns for a company, without taking into account its financial leverage. It compares the risk of an unlevered company to the risk of the market. It is also commonly referred to as "Asset Beta" because the volatility of a company without any leverage is the result of only its asset financed from its equity. Then the levered Beta is converted to unlevered Beta considering the actual debt: equity ratio and effective tax rate to gauge the business risk. In the next step, the composite Beta based on the weighted average of market capitalization separately for Regulated entities and IPPs has been computed to estimate the business risk of the concerned companies. For computing the levered Beta, it has been considered that the actual debt- equity ratio till now will remain same in the future.

11.5.8 It is observed that in the initial years, debt-equity ratio is close to normative debt: equity ratio of 70:30 and this high debt-equity ratio during the construction phase means higher risk for the equity holders during this period and hence, the expected returns are higher. However, once the plant is operational, the debt-equity ratio will reduce due to debt repayments made during the term of the loan and hence, lower the risk for the equity holder. Once all the debt is re-paid, the financial risk is reduced to that of servicing only working capital requirements. As the risk profile reduces over the life of the project, the Commission is of the view that actual debt-equity ratio of the companies is a good proxy of the financial risk involved through the life of the project. On the basis of this approach, the Commission observed that, barring few exceptions, the cost of equity for regulated entities in the power sector works out to be in the range of 12%-15%. Thus, the Commission is of the view that the cost of equity arrived at using CAPM is in line with the existing return on equity during the Tariff Period considering the gestation period of 4 to 7 years and the Commission proposes to continue with the existing rate of 15.50% in the Draft Tariff Regulations. Further, the Commission does not find any merit in increasing the rate of return of equity, as commented by many stakeholders.

11.5.9 Below is the trend of G-Sec vs Market Return vs RoE given by the Commission.

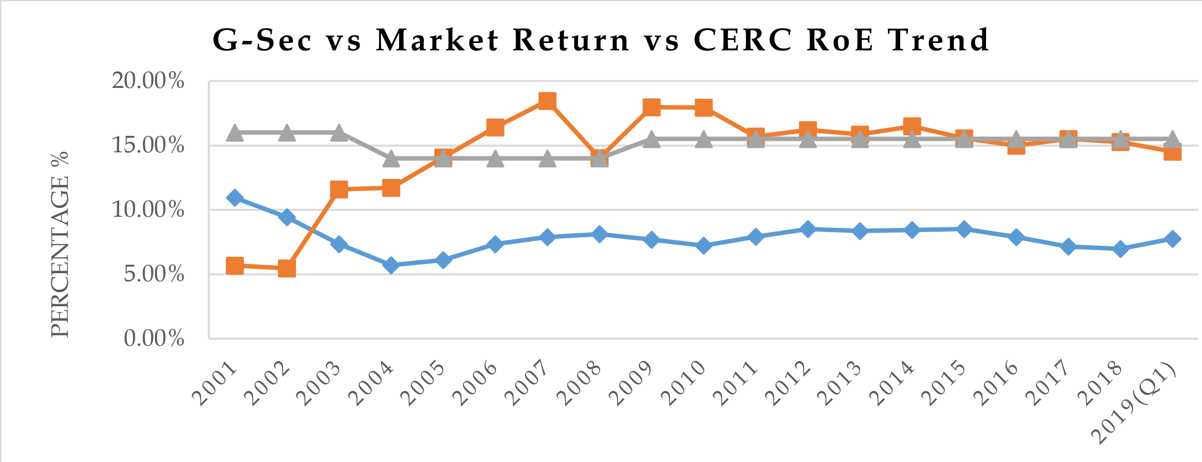


Figure 9: G-SEC vs Market Return vs CERC RoE Trend

11.5.10 In cost plus regime, the recovery of tax on return on equity needs to be allowed based on actual tax paid on RoE, to ensure the recovery of the specified RoE. Therefore, the Commission proposes to retain existing provision of post-tax rate of return on equity with income tax to be recovered on actual basis to the extent of return on equity.

11.5.11 he Commission in its RE Tariff Regulations, 2017 had kept normative rate of return on equity at 14%, to be grossed up by prevailing Minimum Alternate Tax (MAT). However, in case of conventional generation and transmission projects, the Commission has decided to continue with the normative rate of return on equity at 15.5%, to be grossed up by the effective tax rate. The Commission is of the view that the conventional generation and transmission projects have a much longer construction period (3 to 7 years), as compared to the renewable energy projects wherein the construction period is much shorter (1 to 2 years). Therefore, at the same rate of return, the effective IRR for a conventional generation and transmission project would be much lower than that of a renewable energy generation project. Further, the risk during construction period for a conventional generation and transmission project is much higher as compared to that of a renewable energy project.

11.5.12 Regarding additional RoE component of 0.5% on projects commissioned within the specified timeline, it is observed that this clause has practically been irrelevant in case of generating stations, as the projects are not getting commissioned within the specified timelines. In case of transmission, there are only a few instances of early completion of the projects. However, this usually occurs in case of certain elements or part of a much larger transmission scheme or project. The Commission is of the view that the rate of return on equity at 15.5% is sufficient for the projects and the additional RoE on projects commissioned within the specified timeline is not required.

11.5.13 Further, the Commission intends to allow the existing rate of 15.50% in respect of the equity component (up to 30% or as approved by the Commission) of the capital cost up to the cut off date only. In respect of any additional capitalization after cut-off date whether within or beyond the original scope of work, the equity component is proposed to be serviced at the weighted average rate of interest on actual loan portfolio. This provision is not proposed to be applied in case of additional capital expenditure on account of Renovation and Modernisation after useful life.

11.6 Proposed Provisions

11.6.1 In view of above, the Commission proposes provisions in Regulation 30 to 31 in the Draft Tariff Regulations is reproduced below.

"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, 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;

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.

31. Tax on Return on Equity. (1) The base rate of return on equity as allowed by the Commission under Regulation 30 of these regulations shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax paid on income from other businesses including deferred tax liability (i.e. income from business other than business of generation or transmission, as the case may be) shall be excluded for the calculation of effective tax rate.

(2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where "t" is the effective tax rate in accordance with clause (1) of this Regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration-

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 21.55% including surcharge and cess:

Rate of return on equity = 15.50/(1-0.2155) = 19.758%

(ii) In case of generating company or the transmission licensee paying normal corporate tax including surcharge and cess:

(a) Estimated Gross Income from generation or transmission business for FY 2019-20 is Rs 1,000 crore;

(b) Estimated Advance Tax for the year on above is Rs 240 crore;

(c) Effective Tax Rate for the year 2019-20 = Rs 240 Crore/Rs 1000 Crore = 24%;

(d) Rate of return on equity = 15.50/ (1-0.24) = 20.395%

(3) The generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2019-24 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the transmission licensee as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers as the case may be on year to year basis."

12 Interest on Debt

12.1 Background

12.1.1 In 2001 Tariff Regulations and the 2004 Tariff Regulations, the Commission had considered the actual repayment for arriving at outstanding loan at the beginning of Tariff period for the purpose of interest on debt. In the 2009 Tariff Regulations, the Commission, in order to simplify the approach, considered the repayment as equal to the depreciation allowed. The repayment for each of the year of the tariff period 2014-19 was 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 considering the cumulative repayment on a pro rata basis.

12.2 Existing Provisions of the 2014 Tariff Regulations

12.2.1 The existing 2014 Tariff Regulations consists of the following provision regarding Interest on Loan Capital.

*"**26. Interest on loan capital:** (1) The loans arrived at in the manner indicated in regulation 19 shall be considered as gross normative loan for calculation of interest on loan.*

(2) The normative loan outstanding as on 1.4.2014 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2014 from the gross normative loan.

(3) The repayment for each of the year of the tariff period 2014-19 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of decapitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered up to the date of decapitalisation 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 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 generating company or the transmission licensee, as the case may be, shall make every effort to re-finance the loan as long as it results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 2:1.

(8) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

(9) 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 /DICs 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 re-financing of loan."

12.3 Issues discussed in the Consultation Paper

12.3.1 The Consultation Paper had summarised the following issues.

"19. Cost of Debt

19.1 Cost of debt is the cost incurred by the utility in the form of interest payments and upfront fee for raising finances through debt. As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of actual loan portfolio of the utility is considered as the cost of debt. The cost of debt thus arrived at is applied on the normative outstanding loan to compute the annual interest expenses of the utility which is given a pass through in the tariff. This approach does not provide incentive to the utility to lower the cost of borrowings, as even higher rates are given as pass through in tariff.

19.2 Clause (d) of para 5.11 of Tariff Policy, 2016 has stipulated that the utilities should be encouraged and suitably incentivized to restructure their debt for bringing down the tariff. The Tariff Regulations for 2014-19 has provided that the regulated. entities shall make every effort to refinance the loan to lower the interest costs. And for this purpose, while the costs associated with refinancing shall be borne by the beneficiaries, the savings on interest shall be shared between the beneficiaries and the utilities in the ratio of 2:1.

Following key trends have been observed during recent times.

- Regulated entities are availing long term loan from different sources viz. banks, financial institutions, debt markets both in India and abroad. The terms & conditions of debt including the interest rate varies across sources depending upon several factors viz. quantum, tenor, type, timing, etc. As of now utilities are predominantly borrowing from banks and other financial institutions for capital expenditure through non-standardized and negotiated bank loans in the form of corporate loan, project loans, syndicated loans etc. Long term credit rating of utilities varies across utilities. The interest rates at which funds are borrowed from banks/financial institutions/debt market depend upon the credit rating of the utilities.
- As per RBI database, the size of the Indian corporate bond market vis-a-vis GDP is still low in comparison to developed and even several developing countries. However, corporate bonds outstanding as a % of GDP have grown from around 5% in 2012 to 23% during 2017-18. Further, amount of corporate loan raised through issuing bonds in primary market during last 7 years has grown at a CAGR of around 15%. Historically, the corporate bond market has been dominated by PSU's AAA and AA rated bonds. However, the trend seems to be changing with a number of mutual funds investing in debt portfolio with low rated bonds.
- As of now except the better rated utilities like NTPC Ltd. and PGCIL, others utilities are primarily dependent upon banks & financial institutions for meeting their loan requirement. However, with the strengthening of corporate bond market, it will provide an alternative for the companies to raise their finances.
- RBI has gradually revised its repo rate downward from 8% during 2014 to 6% in August, 2017. Since August 2017 RBI has maintained status quo in the policy rates based on the recommendations given by the Monetary Policy Committee (MPC) during its bi-monthly meetings. Further, RBI has introduced the Marginal Cost of Fund Based Lending Rate (MCLR)

system during 2016 as an alternative to the base rate system for efficient transmission of policy rates into the money market. As a result, the bank lending rates have also reduced during this period.

Options for Regulatory Framework

19.4 While allowing the cost of debt as pass through, options available for regulatory framework are either to consider normative cost of debt based on market parameters or actual cost of debt based on loan portfolio. As the tariff is determined for multi-year period and cost of debt varies based on changing market conditions, linking cost of debt to market parameters such as MCLR & G-sec will bring a degree of unpredictability. The regulatory approach evolved so far has been to allow the cost of debt based on actual loan portfolio. This does not incentivize the developers to restructure the loan portfolio to reduce the cost of debt. The current incentive structure may need review to encourage developers to go for reduction of cost of debt.

19.5 (a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects;

b) Review of the existing incentives for restructuring or refinancing of debt;

c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt;"

12.4 Stakeholders' Response

12.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) KERC submitted that for the old loans, the weighted average interest rate and for new loans the interest rate as per MCLR plus certain basis points to cover the future risk is desirable.

b) Few Central Generating Companies submitted that linking cost of debt to benchmarks such as G Sec rate, Repo Rate or MCLR rates shall expose beneficiaries to risk of interest rate volatility and hence is not recommended.

c) Few generating companies and a transmission licensee submitted that in order to incentivize active pursuit of savings consequent to refinancing of loans, the gains should be shared in the ratio of 1:1 between the beneficiary and the Licensee.

d) Few of the State sector companies suggested that, State Government Utilities have majority of loans from their respective States Govt., interest rates of which are not negotiable. Therefore, the actual cost of debt should be considered in such cases.

e) Some State sector companies submitted that, cost of debt is the cost actually incurred by the utility in the form of interest payments and upfront fee for raising finances through debt. Accordingly, existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan is quite judicious and scientific, therefore the same to be continued.

f) One of the Discoms suggested that in the present market conditions, the cost of debt for power sector is very sensitive and therefore the existing option of arriving at weighted average rate of interest duly taking into account of the actual loan and repayments will be the optimal.

g) Few Discoms suggested that, existing approach does not motivate the generating or transmission company to reduce the cost of debt by arranging it through the alternate funds. It is required to link the cost of debt with more reflective MCLR, G-sec or RBI Repo Rate with annual frequency for re-setting and The Commission should also direct the generation/ transmission company to submit steps taken by it to refinance its debt at lower cost and benefit achieved should be shared with the beneficiaries.

h) Some private stakeholders suggested that the cost of domestic borrowing is high and is associated with credit rating of the project as well as of the developers which may or may not be same. They suggested that the normative cost of debt on the basis of present debt market condition is not a viable option.

12.5 Commission's Proposal

12.5.1 The Commission observed that it is not appropriate to specify the same mid-level benchmark interest rate for all the entities as the same may result in gains for some entities and losses for others.. One of the major hurdles in benchmarking of interest rate is that the interest rates on capital loan financed by FIs/banks vary depending on the financial strength and credit rating of the borrowing company. This also varies between public sector and private sector entities. The private sector investor needs to be assured of a rate of return commensurate with the interest. Further, in the current economic scenario, most of the IPPs do not enjoy a good credit rating, and thus have a risk of higher rate of interest on their borrowing.

12.5.2 During the past few years, significant volatility has been witnessed in the interest rates. As a result, it may not be appropriate to benchmark the interest rate with Prime Lending Rate, MCLR or G-Sec rate for all entities. Therefore, the Commission proposes to continue with the existing methodology of weighted average rate of interest calculated on the basis of the actual loan portfolio.

12.5.3 Tariff Policy, 2016 has stipulated that the utilities should be encouraged and suitably incentivized to restructure their debt to reduce the tariff. The Commission would like the generating companies and the transmission licensees to make every effort to re-finance the loans such that it results in net savings in interest expenses. Therefore, the Commission proposes that, while the costs associated with refinancing shall be borne by the beneficiaries, the savings on interest shall be shared between the beneficiaries and the utilities in the ratio of 50:50.

12.6 Proposed Provisions

12.6.1 In view of above, the Commission proposes provisions in Regulation 32 in the Draft Tariff Regulations is reproduced below:-

"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 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 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 re-financing of loan."

13 Interest on Working Capital

13.1 Background

13.1.1 Working Capital is one of the key cost components of the Annual Fixed Cost (AFC) for power sector utilities. In 1990, the K. P. Rao Committee Report discussed at length the need for provision of working capital in the power sector. At that time, one view was not to allow interest on working capital separately, as the tariff payable includes non-cash expense items like returns and depreciation, besides additional recoveries, which would provide enough funds to meet the working capital requirements for operation. The contrary view was that the resources from return and depreciation are used as internal resources for capacity addition programmes and hence, are not available for meeting the working capital requirements. The Committee concluded in favour of inclusion of interest on working capital in the determination of cost of power supply.

13.1.2 Accordingly, the Commission since 2001 Tariff Regulations has approved separate norms for coal and lignite fired stations, gas based stations, hydro generating stations and transmission systems. The components for computation of working capital were primary fuel and secondary/liquid fuel stock (for coal/lignite/gas based generating stations only), O&M expenses, maintenance spares (initially as a percentage of historical capital cost, but subsequently linked to O&M expenses) and receivables.

13.2 Existing Provisions of the 2014 Tariff Regulations

13.2.1 The 2014 Tariff Regulations consists of the following provision regarding Interest on Working Capital.

*"**28. Interest on Working Capital :**(1) The Working Capital shall cover:*

(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 30 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) Cost of coal or lignite and limestone for 30 days 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 29;

(v) Receivables equivalent to two months 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 29;

(iv) Receivables equivalent to two months 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 including communication system:

(i) Receivables equivalent to two months of fixed cost;

(ii) Maintenance spares @ 15% of operation and maintenance expenses

specified in regulation 29; and

(iii) Operation and maintenance expenses for one month.

(2) The cost of fuel in cases covered under sub-clauses (a) and (b) 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 company and gross calorific value of the fuel as per actual for the three months preceding the first month for which tariff is to be determined and no fuel price escalation shall be provided during the tariff period.

(3) Rate of interest on Working Capital shall be on normative basis and shall be

considered as the bank rate as on 1.4.2014 or as on 1st April of the year during the tariff period 2014-15 to 2018-19 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 is later.

(4) Interest on Working Capital shall be payable on normative basis not withstanding that the generating company or the transmission licensee has not taken loan for Working Capital from any outside agency."

13.3 Issues discussed in the Consultation Paper

13.3.1 The Consultation Paper had summarised the following issues.

"20. Interest on Working Capital

20.1 The Working Capital is separately specified by the Commission for coal-based or lignite-fired thermal generating station, open-cycle gas turbine/combined Cycle thermal generating stations and hydro generating station & transmission system. The Working Capital is determined based on fuel stock, inventory of maintenance spares, one-month operation and maintenance cost and two-months receivables depending on the type of thermal generating station, hydro and transmission projects

20.2 The existing Tariff Regulations provides the definition of 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 Reserve Bank of India (RBI), vide ref. RBI/2015-16/273DBR.No.Dir.BC.67/13.03.00/2015-16 dated 17.12.2015, introduced Marginal Cost of funds-based Lending Rate (MCLR). The new methodology for computing benchmark lending rates came into effect from April 1, 2016. The objective of MCLR is to get response of bank faster to policy rate revisions. As per the reference of RBI, MCLR will automatically apply to new loans. However, the existing borrowings linked to the Base Rate may continue till repayment or renewal, as the case may. Alignment of Regulations to above development may therefore, be required.

<u>Options for Regulatory Framework</u>

20.3 (a) Assuming that internal resources will not be available for meeting Working Capital requirement and short-term funding has to be obtained from banking institutions for Working Capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed, or change can be made.

(b) As stock of fuel is considered for Working Capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.

(c) While working out requirement of Working Capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of Working Capital or O&M expenses.

(d) Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses.

(e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative Working Capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking Working Capital with "target availability" can be reviewed."

13.4 Stakeholders' Response

13.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) Few Central sector generating companies have suggested that maintenance spares in working capital is the carrying cost of maintaining spares & whereas maintenance spares in O&M expenses is revenue expenditure. So there is no double calculation of maintenance spares.

b) Few Central sector generating companies submitted that, for working capital Special Allowance and taxes, duties and cess should be included in the receivables as payment rebate is allowed on the billing which includes Special Allowance also. Working capital needs to be dynamic, given the fact that the prices of fuel are varying; adoption of rates at the last three months of the previous control period, for the ensuing five years of the tariff control period would hamper the working capital requirements of the generator.

c) Few State sector companies suggested that, the working capital need to be linked to Plant Availability Factor as the working capital used by the generator is based on its availability and not based on what it has generated and also suggested that interest on working capital should be continued as per the existing regulation, i.e., SBI Base Rate as on 1st April of each financial year.

d) One of the Discoms commented that, considering the factual position prevailing across the country where adequate coal stock is not maintained by the generating stations around the year, Commission may reduce the period for which stock needs to be maintained to a weeks' time while computing the working capital requirement. Further, the maintenance spares @ 15% of O&M expenses while calculating the working capital requirement may not be considered as the spares are already part of O&M expenses or capital.

e) Some Discoms has suggested that, the normative approach of linking working capital with target availability may be reviewed as the working capital is the minimal amount required to run the daily activities of the business efficiently and Receivables needs to be reduced to 1 month of capacity charge and energy charge instead of 2 months as provided in the earlier Regulations.

f) One of the Discoms suggested that special norms for naptha plants are not available. There is requirement for separate norms for working capital since naptha price is very volatile hence fixing price for entire control period will lead to excessive profit or loss for generating stations.

g) Few Discoms suggested that non-cash expenditure including the depreciation and RoE may be excluded from the Working Capital requirement. The stock of fuel considered for Working Capital is very high as generating stations are not maintaining desired fuel stock.

h) A private generating stakeholder stated that actual fuel stock should not be used for computing working capital requirements. It is a fact that most of the plants are operating at less than 7 days coal stock, but that is because of lower coal supply by CIL and its subsidiaries. Generating companies face huge risk of un-planned shutdowns due to lower coal stock. Today there is a need to put clear responsibilities on the coal supplying companies to ensure that at least 1 month of coal stock is available for power companies so that they don't have to rely on auction / open market coal. But reducing working capital because coal companies can't supply fuel is a counterproductive measure that will badly hit the financial / cash performance of generating companies.

i) Some private stakeholders and individuals suggested that in the prevailing scenario of delayed payments by Discoms, lack of adequate payment security mechanism – especially for private generators, pose greater risk perception by bankers towards working capital loan to the private generating companies. Therefore, there is a need to allow higher interest rate on working capital in the MYT Order (say base rate plus 350-400 basis points instead of 250 basis points).

13.5 Commission's Proposal

13.5.1 After examining and reviewing the comments/suggestions of stakeholders received, the Commission proposes as follows.

13.5.2 In the 2014 Tariff Regulations, the cost of coal or lignite for thermal generating stations include one-month fuel cost and cost of fuel towards 15 days of stock for pit head stations and 30 days of stock for non-pit head stations. The Commission, in this regard, had sought information regarding actual annual average fuel stock maintained by the generating stations and the maximum fuel storage capacity of these generating stations. In this regard, the generating stations submitted their actual average fuel stock maintained for FY 2012-13 to FY 2016-17 which is as summarised below.

Table 1: Actual Average Fuel Stock of Pit Head stations (in days)

Generating Station	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average 5 Year Stock
Kahalgaon TPP	2.10	11.20	13.52	16.37	15.62	**11.76**
Korba	3.34	5.00	11.00	19.00	10.00	**9.67**
Ramagundam TPP	5.69	3.81	9.83	16.69	10.51	**9.31**
Rihand TPP	10.54	5.52	2.54	18.02	13.30	**9.98**
Singrauli TPP	11.51	10.82	8.09	17.79	27.27	**15.10**
Sipat TPP	5.02	12.05	3.93	22.74	13.73	**11.49**
Talcher STPP (1000 MW)	2.15	2.17	11.02	18.23	9.44	**8.60**
Talcher TPP	18.49	21.33	31.22	24.95	16.69	**22.54**

Generating Station	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average 5 Year Stock
(460 MW)						
Vindhyanchal TPP	6.47	8.19	4.41	14.12	11.46	**8.93**

Table 2: Actual Average Fuel Stock of Non-Pit Head stations (in days)

Generating Station	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average 5 Year Stock
Badarpur TPP	7.01	17.79	17.27	43.14	12.80	**19.60**
Barh TPP	-	-	9.6	19.0	14.4	**14.36**
Dadri Thermal	1.1	3.8	5.5	24.5	16.8	**10.35**
Farakka TPP	0.94	6.40	7.55	10.98	12.94	**7.76**
Mauda	12	19.96	12.30	31.66	25.96	**20.30**
Simhadri TPP	1.54	1.54	7.01	17.69	23.36	**10.23**
Tanda TPP	32.82	25.77	9.77	46.90	39.83	**31.02**
Unchahar TPP	4.02	5.67	6.77	37.15	24.20	**15.56**

13.5.3 As shown above, in most of the stations, the average fuel stock maintained was well below the allowed normative 15 days for pit head stations and 30 days for non-pit head stations. Except in case of Tanda TPS, wherein the actual average fuel stock maintained was close to 30 days, the average coal stock at most of the generating stations were in the range of around 10-15 days. Further, it is observed that the average stock days for non-pit head plants and pit head plants are 16.5 days and 11.3 days respectively. Therefore, the Commission proposes that the cost of fuel towards fuel stock shall be considered as 15 days for pit head stations and 20 days for non-pit head stations subject to maximum storage capacity.

13.5.4 The Reserve Bank of India vide its Letter No. RBI/2015-16/273 dated 17 December 2015, has directed all Schedule Commercial Banks to price of rupee loans and credit limits w.e.f 1 April 2016. The Commission proposes linking Interest on Working Capital to Marginal Cost of Funds-Based Lending Rate (MCLR). .

13.5.5 The Trend of SBI Base Rate and SBI MCLR (1 Year) is shown below:

Table 3: Historical trend of Base rate vs MCLR

Effective Date	SBI Base Rate (%)	SBI MCLR (1 Year)(%)
01-Jul-16	9.25	9.15
01-Oct-16	9.25	8.90
01-Jan-17	9.25	8.00
01-Apr-17	9.10	8.00
01-Jul-17	9.00	8.00
01-Oct-17	8.95	8.00
01-Jan-18	8.65	7.95
01-Apr-18	8.70	8.15

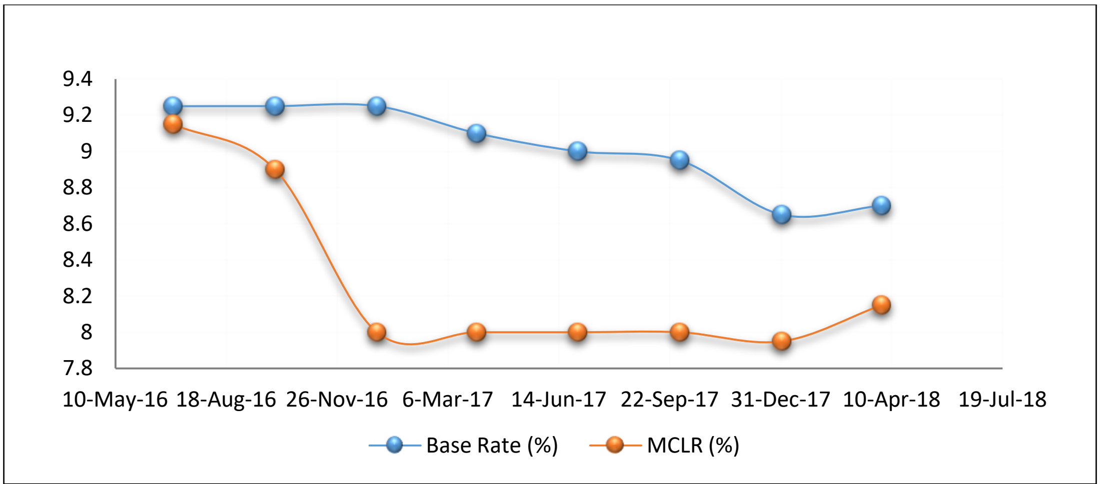


Figure 10: Recent trend of Base rate vs MCLR

13.5.6 The rate of Interest on Working Capital shall be on normative basis and shall be considered as the State Bank's one-year MCLR for the respective financial year of tariff period plus 350 basis point or as on 1st April of the year during the tariff period 2019-20 to 2023-24 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 on commercial operation. The rate of interest for the purpose of truing-up shall be the weighted average MCLR of the respective financial year plus 350 basis points.

13.5.7 The Commission is of the view that depreciation is a non-cash expense but utilized to meet the debt obligation and RoE, though, not part of cash outflow but is part of annual fixed charges. Thus, excluding RoE and depreciation will not be appropriate as a part of receivables for arriving at normative working capital. The Commission, therefore, proposes to include both RoE and depreciation as a part of receivables for arriving at normative working capital.

13.5.8 The Commission has also analysed the average number of days of receivables for various generating companies and transmission licensees. The Commission has observed that in case of a large number of entities, the number of days of receivables ranges around 40 to 50. The Commission has also observed that majority of the Discoms either claim the rebate through early payment, or at least make payment in time to avoid the late payment surcharge. With an objective to further improve the cash cycle in the power sector, the Commission has proposed to apply the late payment surcharge after a period of 45 days from the date of billing from the existing period of 60 days. Considering this proposed reduction in days, it is apt that for the purpose of computing the normative working capital requirement, the number of days of receivables is also correspondingly reduced from the existing 60 days to 45 days.

13.5.9 The Commission notes that there is merit in the fuel cost working to be linked with the latest available prices while computing working capital requirement, as against the present mechanism of calculating the fuel cost at the commencement of tariff period without any price escalation. Therefore, the Commission has proposed for a mechanism to reset the fuel price during every financial year of the tariff period. Similarly, the Commission has also proposed to reset the normative bank rate for every financial year of the tariff period.

13.6 Proposed Provisions

13.6.1 In view of above, the Commission proposes provisions in Regulation 34 in the Draft Tariff Regulations is reproduced as below.

"34. Interest on Working Capital: (1) The working capital shall cover:

(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;

(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 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-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 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."

14 O&M Expenses – Generating Stations

14.1 Background

14.1.1 The Commission during the course of formulation of 2001 Tariff Regulations had laid down that the regulated entities should include in their tariff petition details of year wise actual O&M expenses details (excluding abnormal expenses including water charges) for the previous 5 years duly certified by statutory auditors. The average O&M expenses based on the actuals for the FY 1995-96 to FY 1999-2000 would correspond to the FY 1997-98. This average O&M expense is escalated @ 10% per annum to arrive at base year's O&M expenses of FY 1999-2000. Thereafter, the escalation factor shall be applied @ 6% per annum. In the case of new thermal stations, which had not completed five years of operation, the base O&M expenses was to be fixed at 2.5% of the capital cost for first year of operation duly escalated @ 10% per annum to bring it to base year's O&M expenses of FY 1999-2000. Thereafter, the escalation factor shall be applied @ 6% per annum. A deviation of the escalation factor computed from the actual data that lies within 20% of the above notified escalation factor (which works out to 1.2% on either side of 6%) was to be absorbed by the generating stations. Deviations beyond this limit were to be adjusted on the basis of actual escalation factor.

14.1.2 The Commission in the 2001 Tariff Regulations specified that the O&M Expenses for generating stations in operation for five or more than five years shall be derived on the basis of past five-year actual O&M expenses excluding the abnormal O&M expenses. For new generating stations as well as generating stations, which had not completed five years of operation, the Commission specified norm for O&M expenses for the first year at 2.50% of the actual capital cost. The Commission in the 2004 Tariff Regulations approved normative O&M expenses for thermal stations on the basis of unit sizes of 200/210/250 MW based on the past years actual data, besides approving norms for unit sizes of 500 MW and above. The Commission in the 2009 Tariff Regulations continued with its earlier approach of approving O&M norms on the basis of unit sizes in case of coal based generating stations and on the basis of actual O&M expenses for past years for hydro generating stations. Further, in the 2009 Tariff Regulations, the Commission also specified norms for supercritical units and added another class of unit size of 300/330/350 MW with regard to coal based generating stations. The Commission in the 2004 Tariff Regulations and the 2009 Tariff Regulations also approved separate norms for some of the generating stations of NTPC and DVC. In Tariff Regulations, 2014, the Commission continued with the approach of approving O&M norms on the basis of unit sizes in case of coal based generating stations and on the basis of actual O&M expenses for past years for hydro generating stations. Further, in the 2014 Tariff Regulations, the Commission also introduced norms for thermal generating stations based on coal rejects.

14.2 Existing Provisions of the 2014 Tariff Regulations

*"29. **Operation and Maintenance Expenses:***

(1) Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(a) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations/units referred to in clauses (b) and (d):

(in Rs Lakh/MW)

Year	***200/210/250 MW Sets***	***300/330/350 MW Sets***	***500 MW Sets***	***600 MW Sets and above***
FY 2014-15	*23.90*	*19.95*	*16.00*	*14.40*
FY 2015-16	*25.40*	*21.21*	*17.01*	*15.31*
FY 2016-17	*27.00*	*22.54*	*18.08*	*16.27*
FY 2017-18	*28.70*	*23.96*	*19.22*	*17.30*
FY 2018-19	*30.51*	*25.47*	*20.43*	*18.38*

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2014 in the same station:

200/210/250 MW	*Additional 5th & 6th units*	*0.90*
	Additional 7th & more units	*0.85*

300/330/350 MW	Additional 4th& 5th units	0.90
	Additional 6th& more units	0.85
500 MW and above	Additional 3rd& 4th units	0.90
	Additional 5th& above units	0.85

(b) Talcher Thermal Power Station (TPS), Tanda TPS, Badarpur TPS Unit 1 to 3 of NTPC and Chandrapura TPS Unit 1 to 3 and Durgapur TPS Unit 1 of DVC:

(in RsLakh/MW)

Year	Talcher TPS	Chandrapura TPS (Units 1 to 3), Tanda TPS, Badarpur TPWS (Unit 1 to 3) , Durgapur TPS (Unit 1)
2014-15	43.16	35.88
2015-16	45.87	38.14
2016-17	48.76	40.54
2017-18	51.83	43.09
2018-19	55.09	45.80

(c) Open Cycle Gas Turbine/Combined Cycle generating stations:

(in Rs Lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines
2014-15	14.67	33.43	41.32	26.55
2015-16	15.59	35.70	44.14	28.36
2016-17	16.57	38.13	47.14	30.29
2017-18	17.61	40.73	50.35	32.35
2018-19	18.72	43.50	53.78	34.56

(d) Lignite-fired generating stations:

(in Rs Lakh/MW)

Year	***125 MW Sets***	***TPS-I of NLC***
2014-15	*29.10*	*38.12*
2015-16	*30.94*	*40.52*
2016-17	*32.88*	*43.07*
2017-18	*34.95*	*45.78*
2018-19	*37.15*	*48.66*

(e) Generating Stations based on coal rejects:

Year	***O&M Expenses (in Rs Lakh/MW)***
2014-15	*29.10*
2015-16	*30.94*
2016-17	*32.88*
2017-18	*34.95*
2018-19	*37.15*

(2) The Water Charges and capital spares for thermal generating stations shall be allowed separately:

Provided that water charges shall be allowed 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 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.

(3) 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 01.04.2014:

(in Rs Lakh/MW)

Sr. No.	Name of Station	2014-15	2015-16	2016-17	2017-18	2018-19
A.	**NHPC**					
1	Bairasul	8,696.25	9,274.03	9,890.19	10,547.30	11,248.06
2	Loktak	9,673.64	10,316.36	11,001.78	11,732.74	12,512.26
3	Salal	14,429.58	15,388.29	16,410.68	17,501.01	18,663.78
4	Tanakpur	7,101.62	7,573.45	8,076.63	8,613.24	9,185.51
5	Chamera – I	10,664.95	11,373.53	12,129.19	12,935.05	13,794.46
6	Uri	7,419.40	7,912.34	8,438.04	8,998.66	9,596.54
7	Rangit	4,576.46	4,880.52	5,204.78	5,550.58	5,919.36
8	Chamera – II	7,256.54	7,738.66	8,252.82	8,801.14	9,385.89
9	Dhauliganga	7,181.89	7,659.05	8,167.92	8,710.59	9,289.33
10	Dulhasti	13,746.97	14,660.32	15,634.36	16,673.10	17,780.86
11	Teesta- V	8,297.32	8,848.59	9,436.50	10,063.46	10,732.07
12	Sewa-II	6,157.56	6,566.67	7,002.96	7,468.24	7,964.43
D	**NHDC**					
1	Indira Sagar	8,607.73	9,179.63	9,789.52	10,439.94	11,133.57
2	Omkareshwar	4,515.31	4,815.30	5,135.23	5,476.42	5,840.27
E	**NEEPCO**					
1	Kopili –I	6,132.72	6,540.18	6,974.71	7,438.11	7,932.30
2	Ranganadi	7,033.08	7,500.36	7,998.68	8,530.12	9,096.86
3	Doyang	3,900.10	4,159.22	4,435.56	4,730.26	5,044.54
4	Khandong	1,233.87	1,317.89	1,405.45	1,498.82	1,598.41
5	Kopili II	321.00	342.33	365.07	389.32	415.19
F	**DVC**					
1	Panchet	1,546.42	1,649.17	1,758.74	1,875.59	2,000.20
2	Tilaiya	698.99	745.43	794.95	847.77	904.10

Sr. No.	*Name of Station*	*2014-15*	*2015-16*	*2016-17*	*2017-18*	*2018-19*
3	Maithon	1,914.46	2,041.66	2,177.31	2,321.97	2,476.24

(b) for hydro generating stations of Satluj Jal Vidyut Nigam Limited (SJVNL) and Tehri Development Corporation Limited (THDC), the O&M expenses shall be approved as per the following methodology:

i. The operation and maintenance expenses shall be derived on the basis of actual operation and maintenance expenses for the years 2008-09 to 2012-13, based on the audited balance sheets, excluding abnormal operation and maintenance expenses, if any, after prudence check by the Commission.

ii. The normalised operation and maintenance expenses after prudence check, for the years 2008-09 to 2012-13, shall be escalated at the rate of 6.04% to arrive at the normalized operation and maintenance expenses at the 2012-13 price level respectively and then averaged to arrive at normalized average operation and maintenance expenses for the 2008-09 to 2012-13 at 2012- 13 price level. The average normalized operation and maintenance expenses at 2012-13 price level shall be escalated at the rate of 6.04% to arrive at the operation and maintenance expenses for year 2013-14 and thereafter escalated at the rate of 6.64% p.a., to arrive at the O&M expenses for the period FY 2014-15 to FY 2018-19.

(c) In case of the hydro generating stations, which have not been in commercial operation for a period of three years as on 1.4.2014, operation and maintenance expenses shall be fixed at 2% of the original project cost (excluding cost of rehabilitation and resettlement works) for the first year of commercial operation. Further, in such case, operation and maintenance expenses in first year of commercial operation shall be escalated @6.04% per annum up to the year 2013-14 and then averaged to arrive at the O&M expenses at 2013-14 price level. It shall be thereafter escalated @ 6.64%per annum to arrive at operation and maintenance expenses in respective year of the tariff period.

(d) In case of the hydro generating stations declared under commercial operation on or after 1.4.2014, operation and maintenance expenses shall be fixed at 4% and 2.50% of the original project cost (excluding cost of rehabilitation & resettlement works) for first year of commercial operation for stations less than 200 MW projects and for stations more than 200 MW respectively and shall be subject to annual escalation of 6.64% per annum for the subsequent years."

14.3 Issues discussed in the Consultation Paper

14.3.1 A number of issues were summarised in the Consultation Paper..

(i) The fixed escalation rate used for arriving year on year O&M expenses, takes into account WPI and CPI indexation. However, variations in WPI & CPI index pose challenge in specifying the fixed escalation rate for the entire tariff period. Further, the fixed escalation rate does not capture the variation due to unexpected expenses such as wage revision, etc.

(ii) For new hydro stations whose COD was declared during the tariff period 2014-19, the first year normative O&M has been specified as 4% and 2.5% of original project cost (excluding cost of R&R works) for stations less than 200 MW projects and for stations more than 200 MW respectively. But O&M expenses could vary depending on the type of plant and number of units.

(iii) O&M expense of hydro stations is given as a percentage of capital cost, which is inclusive of IDC & IEDC. Thus, projects with substantial time & cost overrun get higher O&M.

(iv) There could be overlapping of the O&M expenses and the compensation allowance, due to overlapping of items covered under each.

(v) O&M expenses vary if the dispatch of the generating station is continuously low, as in the case of gas/naptha based generating stations. In such cases, specifying recovery of O&M expenses based on installed capacity may need a review.

(vi) In case of expansion of capacity in existing generating station or existing transmission substation, the O&M expenses may vary on account of economies of scale. The O&M expenses have been rationalized by multiplying factor of 0.90, 0.85 and 0.80 to O&M expenses per MW depending on the size of the units. At the same time, different multiplying factor can be prescribed for different unit sizes even in case of the generating stations.

(vii) The O&M expenses of a generating station generally increase with increase in the life completed by it. The new plants require less O&M

expenses whereas older plants require higher O&M expenses. Specifying generic norms for O&M expenses for all plants irrespective of its life may not be fair.

14.3.2 The Consultation Paper sought comments from the Stakeholders on the following:

"(a)Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;

(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.

(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;

(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha and R-LNG based plants).

(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system."

14.4 Stakeholders' Response

14.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) Various Central Generating Companies submitted that the Commission should consider fixing the O&M norm for 2019-24 tariff period, considering the impact of pay revision in the base year and the Variable Pay (Performance Related Pay). Further, the Commission should also include provisions to encourage and incentivize generating companies to carry out concurrent operation of units along with shutdown of unit for R&M.

b) Some of the Central Generating Stations submitted that around 50% of the total O&M expenses is directly related to manpower cost engaged in O&M activity of power plant and this manpower cost is generally increasing at about 7% per annum. It is felt that the current practice of weightage of 60% to WPI and 40% to CPI does not capture the reality in case of escalation of actual O&M expenses. It is suggested that the weightage of CPI should be at least 80% for capturing the escalation of the O&M expenses.

c) Few Central Generating Stations submitted that in view of large-scale integration of renewables, certain thermal stations may be identified for flexing operations. Separate relaxed operating and O&M norms may be prescribed for such flexing stations. All thermal plants would need to flex to absorb variations of RE and low PLF regime which would impact the life of the machine and increase maintenance cost. Therefore, the O&M expenses may be scaled up by 20% to address higher RE penetration and enabling flexing operations.

d) Some State sector generating stations also suggested that as per new environmental laws, items such as installation of pollution control system, installation of FGD system, introduction of NOx control system up-gradation of ESP, mandatory use of treated sewage water by thermal plant, will increase the O&M expenses and is to be taken care of at the time of determination of O&M. As regard to the O&M expenses towards meeting the requirement of Environment Pollution norms and usage of sewage water, the same requires a detailed study. It was suggested that he Commission may carry out the study in consultation with CEA and the report may be circulated for comments of stakeholders.

e) Few State sector companies suggested that any cost covered under Renovation and Modernization is to be approved under the head R&M Expenses along with period of life extension beyond designated useful life of the Generating Station. There should not be any provision in the Tariff Regulations for 'Special Allowance' for incurring the expenditure towards 'Renovation and Modernization'. By allowing Special Allowance for Renovation and Modernisation, the generator is not guaranteeing any tangible benefit to Beneficiaries in terms of life extension, rendering the beneficiaries incapable to justify such expenditure.

f) Some Discoms have suggested that Income from Other Business (e.g. telecom business) may be shared with the end consumer while arriving at the O&M expenses. Most of the State Electricity Regulatory Commission have notified the regulation for sharing of the Income from

Other Business. The Commission may consider a similar approach.

g) Few Discoms have suggested that thermal generating stations are combination of old and newer units. The generating stations, which have been commissioned in the last 10 years, will not require large O&M expenses for running of the plant. Similarly, older plants, which have served their life, may be given the option of phasing out, instead of incurring large Operation and Maintenance expenses and running the plants at low PLF. As the O&M expense norms for old and new thermal stations are common, the beneficiaries are forced to bear the additional expenditure in the form of capacity charges, which also results in higher fixed cost. Therefore, a separate mechanism should be devised for determination of O&M expenses for older plants and newer plants.

h) Some private stakeholders and individuals suggested that the majority of O&M expenses components are fixed in nature and are a sunk cost to the generating station. Therefore, these remain more or less constant irrespective of the continuous low level of operation, which may be on account of low demand and MOD stacking. However, a generating station needs to make itself 'Available'. Therefore, linking O&M expenses norm with level of operations is not logical.

i) Some stakeholders suggested that O&M expenses are expected to increase specifically for gas based plants due to (a) fast change in technology including obsolesce of parts / technology, (b) retention of limited & experienced manpower in India, and (c) LTSA/ LTMA cost. Such costs are required to be incurred for maintaining high availability irrespective of actual offtake.

j) Some stakeholders suggested that the existing escalation mechanism linked with WPI & CPI index takes care of the inflation on routine O&M expenses incurred by generating company, especially, those which are in-house. However, in many instances where the O&M activities are outsourced for a long duration (say 2-3 years), even though awarded through competitive bidding process, the generators are unable to cover the increased expenses under normal escalation rates. Thus, there is a need for a detailed analysis of sensitivity of cost items based on WPI and CPI, based on which the ratio of WPI/CPI can be fixed, and which may be plant specific.

k) Some stakeholder suggested that Income from other businesses, other income, e.g., treasury income such as Interest Income, etc. should not be considered at all for sharing/reduction in AFC, as the risk of loss on these accounts (other business / incidental income) are not shared by the beneficiaries of the generating companies. Further, as the other businesses of the generating company are non-regulated business (even if regulated, may come under a separate authority/statute), the income from the same should not be adjusted. Only in cases of revenue attributable to the utilisation of common assets may be considered and that too should be allocated on the basis of cost sharing / utilisation factor as per Appellate Tribunal Judgment dated 04 April 2007 in Appeal No. 251 of 2006, which clearly stipulates that core and other businesses should be kept in water-tight compartments.

l) NHPC submitted that, it is not correct that the projects with cost and time over get higher O&M. As per the 2014 Tariff Regulations, the O&M cost of the new generating stations is linked to the capital cost of the project and at a later stage the same is linked with the actuals. Further, it was submitted that, unlike thermal power stations, in case of hydropower projects, O&M expenses depend on multiple factors such as remoteness of the location, topography and local social conditions.

m) In addition, NHPC has submitted a comparative analysis of some of its generating stations, whose actuals are lower viz-a-viz the CERC allowed normative O&M expenses as per 2014 Tariff Regulations. This has affected the company's ability to invest in future projects.. Thus, the O&M expenses should be allowed on actual basis subject to prudence check.

n) NEEPCO submitted that there is a need to review the O&M Escalation factor, but the same should be specific to generating stations based on the variation in the past actual O&M Expenses. Further, O&M cost may be reviewed based on the percentage of Capital Expenditure for new hydro power projects. There should be separate O&M Expenses for old generating stations to ensure efficiency. Expenditure incurred due to ageing of plant and machinery need to be recovered.

o) NHDC submitted that the Commission may continue the existing system of O&M expenses as percentage of capital cost. O&M Expenses should be linked with Inflation Index as issued by DIPP (Department of Industrial Policy & Promotion) on yearly basis or with RBI indices.

p) An individual has submitted that certain major expenses such as security expenses may not be considered as part of O&M expenses and should be separately reimbursed or the Commission may provide separate provisions. In addition, the Commission for large old hydro generating stations may determine higher O&M expenses.

14.5 Analysis of Actual O&M Expenses

14.5.1 The Commission through its Order dated November 15, 2017 had directed various Central sector generating companies, joint ventures companies, independent power producers and Central/ inter-State transmission licensees whose tariff is being regulated by the Commission to submit details of actual annual O&M expenses incurred for FY 2012-13 to FY 2016-17 in prescribed format. Subsequently, similar information was also sought for FY 2017-18.

14.5.2 The Central sector generating stations submitted the O&M expenses for FY 2012-13 to FY 2017-18 in the prescribed format with actual break up of expenses incurred for the above mentioned period under various sub-heads. The O&M expenses incurred by these generating stations can be broadly classified into three heads, namely, employee expenses, repair and maintenance expenses and administrative and general expenses. Each of these major heads of the O&M expenses incurred by generating stations, have further been segregated under various sub-heads, and these have been evaluated by the Commission. Based on the detailed analyses, the Commission has followed a systematic approach for arriving at the actual normalised O&M expenses to be considered for preparation of norms.

a) Some of the employee related expenses namely ex-gratia, incentives, productivity linked incentives and performance related pay are linked to efficient operation of generating station. These types of expenses are contingent upon the actual performance of the individual generating station and are payable only when the generating station achieves targeted operational norms. The Commission has been consistently following the principle that such incentives and performance related pay should be paid by the generating company from the increase in revenue due to reduced down time and efficient operations of the generating stations. Therefore, for computing O&M expenses norms, these types of expenses are excluded from the actual O&M expenses. Further, some of the expenses such as donations, provisions, community development expenses, CSR expenses, loss of stores, RLDC fee, Filing Fee are expenses, which don't form a part of O&M expenses for determination of norms and thus have been excluded while computing the O&M expenses norms.

b) Further some of the expenses like prior period expenses, arrears, etc., booked under the head O&M expenses are one-time expenses. Therefore, such expenses of non-recurring nature have not been considered for computing the O&M expenses norms.

c) Where disproportionate year on year increase of expenses under sub-heads were observed, justifications were sought from the generating companies. In such cases, the Commission, with an objective to normalise the same, has applied average escalation rate determined for FY 2013-14 to FY 2017-18 which works out to be 1.49% (WPI) (as per 2011-12 base year series) and 5.76% (CPI) on the corresponding expenses under the sub-head for the immediate preceding year. The following table provides the summary of computation of average WPI and average CPI.

Table 4: Summary computation of Average WPI and Average CPI

Year	Average CPI	% Change	Average WPI	% Change
FY 2012-13	215		107	
FY 2013-14	236	9.68%	112	5.20%
FY 2014-15	251	6.29%	114	1.26%
FY 2015-16	265	5.65%	110	-3.68%
FY 2016-17	276	4.12%	112	1.76%
FY 2017-18	284	3.08%	115	2.92%
Average		**5.76%**		**1.49%**

d) Further, as the Commission has proposed to consider allowing water charges and security expenses at actuals for each of the generating station separately, the same has not been considered as a part of O&M expenses for thermal generating stations. However, Water Cess being a statutory duty payable to respective State Pollution Control Board, on account of discharge of effluent has been considered while computing the O&M expenses norms.

e) Where steep year on year increase in expenses under various heads were observed, the Commission normalised the same suitably by applying the average escalation rate of WPI (1.49%) or CPI (5.76%), depending upon the nature of expenses , on the preceding year's corresponding expense figure.

f) For NTPC stations, it was generally observed that the employee expenses for FY 2016-17 and FY 2017-18 were on the higher side due to impact of wage revision. During the FY 2016-17, the pay revision impact is provided for 3 months (i.e. January 2017-March 2017), while during FY 2017-18, the same is provided for the entire financial year. This pay revision impact has been separated from employee expense during the respective financial year, which works out to INR 1.60 Lakh/MW for coal based generating stations and INR 1.38 Lakhs/MW for gas based generating stations. The same has been considered while deriving the norms for O&M expenses.

14.5.3 The Commission has thus derived the normalised O&M expenses actually incurred by the generating stations for approving the norms for thermal generating stations.

A. Thermal Generating Stations

14.5.4 The Commission in 2014 Tariff Regulations approved norms of O&M expenses based on the unit sizes. These unit sizes were classified as 200/210/250 MW, 300/330/350 MW, 500 MW and above (sub-critical) and 600 MW and above (super critical). The Commission has analysed the actual O&M expenses from FY 2013-14 to FY 2017-2018 (and for FY 2012-13 to FY 2016-17 for plants not having FY 2017-18 data), as summarised above. The Commission has observed that several generating stations, for which O&M expenses data have been submitted, have combination of different unit sizes. Therefore, the Commission has separately analysed the O&M

expenses data of the generating stations having single unit type configuration and considered the same for computing O&M expenses norms for respective unit sizes. For this purpose, the stage wise O&M expenses of a thermal generating station have been derived by applying the weighted average sum-product of installed capacity and existing O&M expense norms (in Rs. Lakh per MW).

14.5.5 For 200/210/250 MW units, the Commission has considered the O&M expenses of the following stations.

a) Dadri Coal Stage 1

b) Unchahar TPP

c) Ramagundam Stage 1

d) Korba Stage 1

e) Kahalgaon Stage 1

f) Chandrapura Unit 7-8

g) NLC TPS II

14.5.6 The actual O&M expenses for these stations for FY 2013-14 to FY 2017-18 are as shown below.

Table 5: Actual O&M expenses for 200 / 210 / 250 MW Series Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Five Year Average
Dadri Coal Stage 1	-	21.85	23.27	24.04	24.76	26.08	24.00
Unchahar TPP	-	28.12	26.73	27.25	28.53	30.27	28.18
Ramakundam Stage 1	-	24.20	26.09	26.59	27.95	29.62	26.89
Korba Stage 1	-	23.42	25.49	26.87	28.35	29.17	26.66
Kahalgaon Stage 1	-	23.88	24.93	28.01	27.19	28.32	26.46
Chandrapura Unit 7-8	22.32	22.54	22.58	23.53	24.77	-	23.15
NLC TPS - II	22.75	23.62	23.98	23.79	24.67	-	23.76

*Data for FY 2017-18 in case of DVC & NLC is not available.

14.5.7 Stations such as Unchahar TPP, Ramagundam Stage 1, Korba Stage 1, Kahalgaon Stage 1, Farakka Stage 1 have not been considered for computation of O&M expenses norms, because of their disproportionately high actual O&M expenses during past years.

14.5.8 Stations with only 500 MW sized units are as stated below:

a) Simhadri TPS

b) Talcher STPP

c) Rihand TPS

d) Sipat TPP Stage 2

e) Singrauli TPP Stage 2

f) Dadri TPP Stage 2

14.5.9 The actual O&M expenses for these stations for FY 2013-14 to FY 2017-18 are as shown below.

Table 6: Actual O&M expenses for 500 MW Series Thermal Generating Stations

(INR in Lakh)

Generating Stations	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Last Five Year Average
Talcher STPP	15.71	15.80	16.47	17.10	18.35	16.69
Simhadri	15.92	15.70	15.93	16.46	17.65	16.33
Rihand	16.94	16.54	16.60	16.92	17.64	16.93
Sipat TPP Stage 2-2x500MW	14.18	14.63	15.19	15.84	16.70	15.31
Singrauli TPP Stage 2- 2X500MW	16.18	16.02	17.02	17.37	18.19	16.96
Dadri Coal Stage 2 - 2x490MW	15.60	15.58	16.10	16.58	17.47	16.27

14.5.10 Stations such as Ramagundam Stage 2, Korba Stage 2, Kahalgaon Stage 2, Farakka Stage 2 have not been considered for computation of O&M expenses norms, because of their disproportionate actual O&M expenses during last five years.

14.5.11 For supercritical unit of 600 MW and above, only Sipat Stage 1 (3X 660 MW) is operational. The actual O&M expenses for this station for FY 2013-

14 to FY 2017-18 are as shown below.

Table 7: Actual O&M expenses for 600 / 660 MW Series Thermal Stations

(INR Lakh per MW)

Generating Station	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Last Five Year Average
Sipat TPP Stage 1 1,980 MW	12.77	13.17	13.67	14.26	15.03	13.78

14.5.12 As following stations have smaller sized units, separate norms have been provided for them under the previous Tariff Regulations.

a) Talcher TPS

b) Tanda TPS, Chandrapura TPS, and Durgapur TPS

14.5.13 Only Tanda and Chandrapura thermal generating stations have all small sized units of 110 MW each and 130 MW each, respectively.

14.5.14 The actual O&M expenses for these stations for FY 2013-14 to FY 2017-18 are as shown below.

Table 8: Actual O&M expenses for small sized Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Five Year Average
Talcher	-	43.00	44.51	46.66	48.73	50.31	46.64
Tanda	-	41.79	40.54	42.39	43.24	46.31	42.85
Chandrapura Unit 1-3 3x130 MW	32.19	32.51	33.90	35.33	37.19	-	34.22
Durgapur	38.44	40.02	40.23	40.45	42.18	-	40.27

** Data for FY 2017-18 for DVC is not available.*

14.5.15 For lignite fired stations the Commission had approved separate norms for NLC TPS-I. The actual expenses are as shown below.

Table 9: Actual O&M expenses for NLC TPS I Generating Station

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average
NLC TPS I	33.13	34.74	34.69	32.85	34.74	34.03

14.5.16 For gas based stations other than small gas turbines, the actual O&M expenses are as shown below.

Table 10: Actual O&M expenses for NTPC Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Average
Anta	17.84	18.56	18.39	16.30	18.16	17.85
Aurayia	13.21	13.65	12.73	12.27	11.86	12.75
Dadri	10.41	10.34	9.65	11.69	10.45	10.51
Faridabad	15.33	15.60	13.86	14.10	16.84	15.15
Gandhar	11.79	11.11	9.25	10.93	11.84	10.98
Kawas	13.80	13.52	11.88	12.77	15.39	13.47
Kayamkulam GPP	18.40	17.99	20.11	17.95	17.60	18.41

14.5.17 For small gas turbine power generating station and Agartala GPS, the actual normalised O&M expenses are as shown below.

Table 11: Actual O&M expenses for NEEPCO Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Five Year Average
Assam GPS	41.96	42.86	45.61	31.63	27.65	37.94
Agartala GPS	33.85	29.33	31.67	31.23	33.01	31.82

14.5.18 For advance class gas power stations, actual normalised O&M expenses has not been considered as out of total three such generating stations, the average plant load factor during last five years of two generating stations, namely RGPPL and Sugen was 14% and 35% respectively, while the third generating station, namely OTPC has been operational for less than three years till FY 2016-17. Therefore, it would not be appropriate to determine the normative O&M expenses for the tariff period 2019-24, based on the actual data available from FY 2012-13 to FY 2016-17.

B. Hydro Generating Stations

14.5.19 The Commission in the 2009 Tariff Regulations specified the approach for approving the O&M expenses for the hydro generating stations, after considering the actual O&M expenses based on the Audited Balance Sheet. However, there were no specific station wise norms. For tariff period 2014-2019, the Commission decided to specify station wise O&M norms based on the actual normalised O&M expenses.

14.5.20 In response to the Commission's Order No. L-1/225/2017/CERC, dated 10 November 2017, NHPC, NHDC, THDCIL, NEEPCO, DVC, NTPC (Koldam) have submitted their actual O&M expenses for the period from FY 2012-13 to FY 2016-17. Subsequently, NHPC and NTPC have submitted their actual O&M expenses for FY 2017-18 also.

14.5.21 The O&M expenses are usually worked out based on three major expenses heads, viz., employee expenses, A&G expenses and R&M expenses. Apart from these major expenses heads the Commission further allocated the additional expenses heads viz., allocation of corporate expenses, other expenses and revenue recoveries in the following ratio.

Table 12: Expense Head Allocation

Expense Head	Employee Expenses	A&G Expenses	R&M Expenses	Remarks
Corporate Office Expenses	75.00%	25.00%	0.00%	Considered the allocation ratio of NHPC.
Other Expenses	0.00%	100.00%	0.00%	Expenses such as Stationery, Printers, etc. Details of break is sought for proper allocation
Revenue Recoveries	33.33%	33.33%	33.33%	No breakup provided by NHPC, data gap for the same have been raised to respective Gen. Co.

14.5.22 Further, in FY 2016-17, the employee expenses for the generating Stations were on a higher side especially in case of NHPC, which was due to impact of wage revision in the last quarter of FY 2016-17, whereas in FY 2017-18

NHPC has provided their employee expenses excluding the impact of the same. Thus, the Commission while normalising the actual O&M expenses has not considered the impact of wage revision on FY 2016-17 and FY 2017-18. The same shall be separately dealt with as per the provisions under the Tariff Regulations.

14.5.23 The actual normalised O&M expenses of hydro generating stations, (except NHPC and NTPC – Koldam), for which actual O&M expenses from FY 2012-13 to FY 2016-17 has been considered are as shown under.

Table 13: Actual O&M expenses for Hydro Stations except NHPC and NTPC

(INR Lakhs)

Particulars	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17
THDC					
THDC Stage I	20,718.50	19,114.62	22,415.99	23,887.69	22,923.68
KHEP	8,839.09	9,840.67	11,068.78	11,007.63	12,041.48
NHDC					
Indira Sagar	8,034.80	8,723.39	9,152.34	9,676.60	10,443.35
Omkareshwar	4,947.69	5,462.61	5,502.66	5,940.03	6,400.96
SJVNL					
Naptha Jhakari	20,574.10	24,029.89	26,917.30	29,242.30	28,639.42
NEEPCO					
Kopili	9,232.51	10,176.15	8,893.89	10,643.84	9,818.29
Doyang	3,669.45	4,026.08	4,105.11	4,544.20	5,840.43
Ranganadi	9,433.61	8,915.33	7,999.84	12,163.94	8,957.00
DVC					
Maithon	1,909.51	2,361.87	2,049.67	2,253.13	2,777.99
Panchet	1,373.29	1,651.20	1,747.17	1,821.85	2,007.26
Tilaya	614.11	791.37	566.79	644.55	916.20

14.5.24 The actual normalised O&M expenses of the NHPC's hydro generating stations and NTPC - Koldam for which actual O&M expenses from FY 2013-14 to FY 2017-18 has been considered, are shown as under.

Table 14: Actual O&M expenses for NHPC and NTPC Hydro Generating Stations

(INR Lakhs)

Particulars	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18
NHPC					
Bairasul	7,291.84	7,039.46	6,336.64	6,709.85	6,719.08
Loktak	6,984.86	8,195.88	7,782.03	8,146.72	8,067.43
Salal	14,981.55	17,141.50	15,589.48	16,014.46	15,303.62
Tanakpur	7,493.59	8,189.03	9,040.07	8,458.56	10,113.21
Chamera-I	8,744.26	8,610.34	9,659.24	10,903.34	10,596.63
Uri I	6,811.70	7,619.15	8,514.11	9,111.30	8,582.46
Rangit	3,773.72	3,959.42	4,541.80	4,791.42	4,926.42
Chamera-II	8,238.83	8,073.29	7,800.69	9,673.02	10,193.13
Dhauliganga	5,093.58	6,491.83	8,027.67	7,787.21	8,831.00
Dulhasti	13,711.05	15,515.91	15,228.10	15,964.03	16,081.23
Teesta-V	8,781.00	8,970.43	10,082.88	10,584.25	11,744.73
Sewa-II	4,962.87	5,408.11	6,163.45	5,523.61	7,118.86
TLDP III	5,810.13	4,911.22	6,244.94	6,936.54	7,170.97
Chamera III	7,193.80	6,774.89	6,221.38	8,776.57	8,451.08
Chutak	2,438.02	2,801.51	2,872.03	3,120.20	3,343.60
Nimmo Bazgo	719.95	2,872.43	3,387.69	3,683.29	3,874.05
Uri II	2,638.76	5,751.84	6,519.01	6,971.22	7,207.63
Parbati III	-134.90	6,222.57	6,297.64	7,140.97	7,749.11
NTPC					
Koldam	-	-	6,405.29	11,300.39	10,616.36

14.6 Commission's Proposal – Thermal Generating Stations

14.6.1 After examining r and reviewing comments/suggestions of stakeholders received the Commission has proposed the following.

Escalation Rate:

14.6.2 The Escalation rate computed based on the five -year average of WPI for FY 2013-14 to FY 2017-18 works out to 1.49%, while that of CPI for the same period works out to 5.76%. Considering the 60:40 weightage for WPI and CPI respectively, the escalation rate works out to 3.20%. The Commission observes that actual O&M expenses after normalisation during the period from FY 2013-14 to FY 2017-18 have increased at a rate of approx. 3.31% for coal based generating stations of NTPC and approx. 1.16% for gas based generating stations. Though, the normalised O&M expenses escalation rate is comparable to the weighted average escalation rate of 3.20%, the Commission is of the view that average CPI and WPI indices are a fair indicator of inflation. In this context, for the purpose of escalation till FY 2018-19, the Commission proposes to consider the escalation rate of 3.31% and 1.16% for coal and gas generating stations respectively and thereafter for projecting O&M expenses norms for the period from FY 2019-20 to FY 2023-24, the weighted average escalation rate of 3.20% is applied for all generating stations.

Norms:

14.6.3 The Commission based on the actual O&M expenses for FY 2013-14 to FY 2017-18 (for FY 2012-13 to FY 2016-17 for stations not having FY 2017-18 data) has re-computed the O&M expenses for FY 2015-16 (FY 2014-15 for stations not having FY 2017-18 data) by taking average of five-year O&M expenses after escalating annual normalised O&M expenses by 3.31% for coal based and 1.16% for gas based generating stations till FY 2018-19. O&M expenses thus computed for FY 2018-19, has been escalated further considering 3.20% to arrive at the O&M expenses for FY 2019-20 to FY 2023-24.

14.6.4 The Commission proposes to approve the norms based on the actual O&M expenses incurred after normalisation. For the purpose of determining norms for 200/210/250 MW units, the Commission has considered the O&M expenses for the following stations:

a) Dadri Coal Stage 1

b) Unchahar TPP

c) Ramakundam Stage 1

d) Korba Stage 1

e) Kahalgaon Stage 1

f) Chandrapura Unit 7-8

g) NLC TPS II

14.6.5 The O&M expenses for the above generating stations are shown as below.

Table 15: Projected O&M expenses for 200/210/250 MW Series Thermal Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals						Derived	Projected				
Dadri Coal Stage 1	-	21.85	23.27	24.04	24.76	26.08	28.12	29.02	29.94	30.90	31.89	32.91
Unchahar TPP	-	28.12	26.73	27.25	28.53	30.27	32.73	33.77	34.85	35.97	37.12	38.31
Ramakundam Stage 1	-	24.20	26.09	26.59	27.95	29.62	31.30	32.31	33.34	34.41	35.51	36.65
Korba Stage 1	-	23.42	25.49	26.87	28.35	29.17	31.05	32.04	33.07	34.12	35.22	36.34
Kahalgaon Stage 1	-	23.88	24.93	28.01	27.19	28.32	30.83	31.82	32.84	33.89	34.97	36.09
Chandrapura Unit 7-8	22.32	22.54	22.58	23.53	24.77	-	26.37	27.21	28.08	28.98	29.91	30.87
NLC TPS - II	22.75	23.62	23.98	23.79	24.67	-	27.07	27.94	28.83	29.75	30.71	31.69
Average (200 MW)	**22.54**	**23.95**	**24.72**	**25.73**	**26.60**	**28.69**	**29.64**	**30.59**	**31.56**	**32.57**	**33.62**	**34.69**

14.6.6 For determining the norms for 500 MW units based on sub critical technology, the Commission has considered the following stations:

a) Simhadri TPS
b) Talcher STPP
c) Rihand TPS
d) Sipat TPP Stage 2
e) Singrauli TPP Stage 2
f) Dadri TPP Stage 2

14.6.7 The O&M expenses for the above generating stations are shown as below:

Table 16: Projected O&M expenses for 500 MW Series Thermal Stations

(INR Lakh per MW)

Generating Stations	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals					Derived	Projected				
Simhadri TPS	15.71	15.80	16.47	17.10	18.35	19.66	20.29	20.94	21.61	22.30	23.01
Talcher STPP	15.92	15.70	15.93	16.46	17.65	20.05	20.69	21.36	22.04	22.75	23.47
Rihand	16.94	16.54	16.60	16.92	17.64	20.32	20.97	21.64	22.33	23.05	23.78
Sipat TPP Stage 2	14.18	14.63	15.19	15.84	16.70	18.53	19.13	19.74	20.37	21.02	21.70
Singrauli Stage 2	16.18	16.02	17.02	17.37	18.19	20.35	21.00	21.67	22.37	23.08	23.82
Dadri Stage 2	15.60	15.58	16.10	16.58	17.47	19.59	20.21	20.86	21.53	22.22	22.93
Average (500 MW)	**15.76**	**15.71**	**16.22**	**16.71**	**17.67**	**19.75**	**20.38**	**21.04**	**21.71**	**22.40**	**23.12**

14.6.8 The O&M expenses for super critical technology is available only for Sipat

Stage 1 (3 X 660 MW) for the entire period from FY 2013-14 to FY 2017-18. The Commission observed that the actual O&M expenses for Sipat Stage 1 are much lower than the norms approved in 2014 Tariff Regulations at 0.9 times of the norms specified for 500 MW Stations. Therefore, the Commission has now proposed to compute the norms for 660 MW units sized sets based on actual O&M expenses of Sipat Stage 1, as shown below:

Table 17: Projected O&M expenses for 600/660 MW Series Thermal Stations

(INR Lakh per MW)

Generating Station	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals					Derived	Projected				
Sipat Stage 1	12.77	13.17	13.67	14.26	15.03	16.85	17.39	17.94	18.52	19.11	19.72
Average 600 / 660 MW	**12.77**	**13.17**	**13.67**	**14.26**	**15.03**	**16.85**	**17.39**	**17.94**	**18.52**	**19.11**	**19.72**

14.6.9 The Commission, for determining the O&M expenses for 300/330/350 MW units, in continuation with its earlier approach proposes to consider the average O&M expenses norms for 200/210/250 MW and 500 MW units.

14.6.10 The Commission proposes to approve norms for stations having smaller sized units, based on the actual normalised O&M expenses.

14.6.11 Since actual O&M expenses for 800 MW ultra-super critical technology is not available, the Commission proposes to specify the norms for these stations at slightly lower levels (at 0.9 times) as compared to 600 / 660 MW units.

14.6.12 For stations with 100/110/130/140 MW units, the Commission proposes to approve norms based on the actual performance of the plant. Since Tanda TPS comprises of only 110 MW units, the actual normalised O&M expenses has been considered for approving norms for similar sized units.

Table 18: Projected O&M expenses for small sized Thermal Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20 to FY 2023-24
Talcher TPP	-	43.00	44.51	46.66	48.73	50.31	53.08	54.78
Average	**-**	**43.00**	**44.51**	**46.66**	**48.73**	**50.31**	**53.08**	**54.78**

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20 to FY 2023-24
Tanda TPP	-	41.79	40.54	42.39	43.24	46.31	48.90	50.47
Chandrapura Unit (1-3)	32.19	32.51	33.90	35.33	37.19	-	38.99	40.23
Average	**32.19**	**37.15**	**37.22**	**38.86**	**40.215**	**46.31**	**43.945**	**45.35**

*Data for Chandrapura Unit (1-3) for FY 2017-18 is not available.

14.6.13 The O&M expenses norms of older generating stations have become relatively high, almost double of the 200/210/250 MW sized units. Taking into account high O&M expenses norms as well as operational norms, the generating companies may consider retiring such generating stations. This needs to be decided between the generating companies and beneficiaries. However, the Commission is not inclined to further escalate the O&M expenses norms for these vintage stations. Therefore, the Commission propose to freeze the O&M expenses norms worked out for FY 2019-20 to be made applicable during the entire tariff period.

14.6.14 For NLC TPS I, the Commission proposes to approve the norms based on the actual O&M expenses. For 125 MW lignite fired station, the Commission proposes to approve the norm based on the actual O&M expenses incurred for Barsingsar TPS.

Table 19: Projected O&M expenses for NLC TPS I Generating Station

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals					Derived	Projected				
NLC TPS I	33.13	34.74	34.69	32.85	34.74	38.76	40.01	41.29	42.61	43.97	45.38
125 MW sets	25.38	23.76	26.11	23.93	25.40	28.38	29.29	30.23	31.20	32.20	33.23

14.6.15 The Commission, for generating stations based on coal rejects, proposes to approve the norms for O&M expenses as approved for 125 MW lignite fired stations.

14.6.16 For determination of O&M expenses norms for gas based stations other than small gas turbine for FY 2019-20 to FY 2023-24, the Commission has considered actual normalised O&M expenses for FY 2013-14 to FY 2017-18 of all the gas based generating stations of NTPC.

Table 20: Projected O&M expenses for NTPC Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals					Derived	Projected				
Anta	17.84	18.56	18.39	16.30	18.16	19.88	20.11	20.75	21.41	22.10	22.81
Aurayia	13.21	13.65	12.73	12.27	11.86	14.59	14.76	15.23	15.72	16.22	16.74
Dadri	10.41	10.34	9.65	11.69	10.45	12.28	12.42	12.82	13.23	13.65	14.09
Faridabad	15.33	15.60	13.86	14.10	16.84	17.08	17.27	17.83	18.40	18.99	19.59
Gandhar	11.79	11.11	9.25	10.93	11.84	12.77	12.92	13.33	13.76	14.20	14.65
Kawas	13.80	13.52	11.88	12.77	15.39	15.34	15.52	16.02	16.53	17.06	17.60
Kyakulam GPP	18.40	17.99	20.11	17.95	17.60	20.45	20.69	21.35	22.04	22.74	23.47
Average	**14.40**	**14.40**	**13.70**	**13.72**	**14.59**	**16.06**	**16.24**	**16.76**	**17.30**	**17.85**	**18.42**

14.6.17 For small gas turbine stations, the Commission has considered Assam GPS for determination of O&M norms. For Agartala Gas based stations, the Commission has considered the actual normalised O&M expenses for FY 2012-13 to FY 2016-17.

Table 21: Projected O&M expenses for NEEPCO Gas based Generating Stations

(INR Lakh per MW)

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2018-19	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Actuals					Derived	Projected				
Assam GPS	41.96	42.86	45.61	31.63	27.65	39.73	41.00	42.31	43.66	45.06	46.50
Agartala GPS	33.85	29.33	31.67	31.23	33.01	33.31	34.38	35.48	36.62	37.79	39.00

14.6.18 For gas based advance F Class machines, the Commission has observed large variation between the actual expenses of three generating stations as against existing O&M expenses norms. The Commission has further noted that as there is significant difference in the average PLF levels of these three generating stations during the past 5 years, it would not be appropriate to consider the actual O&M expenses to determine the norm for the new tariff period. Therefore, the Commission has decided to consider the O&M expenses norms for FY 2018-19 as base figure, escalate the same by 3.20%

(escalation factor for thermal generating stations) and take 70% of the same to arrive at the base figure for FY 2019-20. Thereafter, it is escalated by 3.20% for deriving the figures for the remaining years of the tariff period.

Table 22: Projected O&M expenses for Advance F Class Machines

(INR Lakh per MW)

Generating Stations	FY 2018-19	FY 2019-20	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
	Existing Norm	Derived	Projected				
Advance F Class Machines	34.56	35.67	25.00	25.80	26.63	27.48	28.36

14.7 Commission's Proposal – Hydro Generating Stations

Escalation Rate:

14.7.1 The Commission has worked out the escalation rate of 4.70% based on the five years average CPI and WPI indices for FY 2013-14 to FY 2017-18 by considering the weightage of 75% CPI and 25% WPI. It was observed that, post normalisation the overall increase in the O&M Expenses from FY 2012-13 to FY 2016-17 (FY 2013-14 to FY 2017-18, in case of NHPC) was around 5.00%. While for some of the hydro generating stations the y-o-y growth was on a higher side, For others, the actual growth was on a lower side.. Thus, while the average of CPI and WPI indices are an indicator of inflation, the average increase in actual normalised O&M expenses for hydro generating stations have been marginally higher than the escalation rate of 4.70%. Therefore, for the purpose of escalation till FY 2018-19, the Commission proposes to consider the escalation rate of 5.00% in case of hydro generating stations.

Norms :

14.7.2 The Commission has worked out O&M expense for the base year i.e. FY 2018-19, by taking the five years average of actual normalised O&M expenses of FY 2012-13 to FY 2016-17 (FY 2013-14 to FY 2017-18, in case of NHPC) and thereby escalating it with 5.00% of average actual growth rate. The derived O&M expense for base year FY 2018-19, is further escalated with an escalation factor of 4.70% derived after considering 5 years CPI & WPI ratio as discussed in above paragraph, for deriving the projected O&M Expenses for the tariff period FY 2019-20 to FY 2023-24.

14.7.3 Thus, for hydro generating stations having completed more than three years of operation after CoD as on 01 April 2019, the O&M expenses are as shown below.

Table 23: Actual O&M expenses for Hydro Stations except NHPC and NTPC

(INR Lakh)

Particulars	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average	Derived Base Year (FY 2018-19)
THDC							
THDC Stage I	20,718.50	19,114.62	22,415.99	23,887.69	22,923.68	**21,812.10**	**26,508.27**
KHEP	8,839.09	9,840.67	11,068.78	11,007.63	12,041.48	**10,559.53**	**12,833.01**
NHDC							
Indira Sagar	8,034.80	8,723.39	9,152.34	9,676.60	10,443.35	**9,206.10**	**11,188.18**
Omkareshwar	4,947.69	5,462.61	5,502.66	5,940.03	6,400.96	**5,650.79**	**6,867.41**
SJVNL							
Naptha Jhakari	20,574.10	24,029.89	26,917.30	29,242.30	28,639.42	**25,880.60**	**31,452.72**
NEEPCO							
Kopili	9,232.51	10,176.15	8,893.89	10,643.84	9,818.29	**9,752.94**	**11,852.76**
Doyang	3,669.45	4,026.08	4,105.11	4,544.20	5,840.43	**4,437.05**	**5,392.36**
Ranganadi	9,433.61	8,915.33	7,999.84	12,163.94	8,957.00	**9,493.94**	**11,538.00**
DVC							
Maithon	1,909.51	2,361.87	2,049.67	2,253.13	2,777.99	**2,270.44**	**2,759.26**
Panchet	1,373.29	1,651.20	1,747.17	1,821.85	2,007.26	**1,720.15**	**2,090.51**
Tilaya	614.11	791.37	566.79	644.55	916.20	**706.60**	**858.74**

Table 24: Actual O&M expenses for NHPC and NTPC Hydro Stations

(INR Lakh)

Particulars	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Average	Derived Base Year (FY 2018-19)
NHPC							
Bairasul	7,291.84	7,039.46	6,336.64	6,709.85	6,719.08	**6,819.37**	**7,893.28**
Loktak	6,984.86	8,195.88	7,782.03	8,146.72	8,067.43	**7,835.38**	**9,069.29**
Salal	14,981.55	17,141.50	15,589.48	16,014.46	15,303.62	**15,806.12**	**18,295.24**
Tanakpur	7,493.59	8,189.03	9,040.07	8,458.56	10,113.21	**8,658.89**	**10,022.48**

Particulars	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	Average	Derived Base Year (FY 2018-19)
Chamera-I	8,744.26	8,610.34	9,659.24	10,903.34	10,596.63	**9,702.76**	**11,230.74**
Uri I	6,811.70	7,619.15	8,514.11	9,111.30	8,582.46	**8,127.74**	**9,407.69**
Rangit	3,773.72	3,959.42	4,541.80	4,791.42	4,926.42	**4,398.56**	**5,091.23**
Chamera-II	8,238.83	8,073.29	7,800.69	9,673.02	10,193.13	**8,795.79**	**10,180.94**
Dhauliganga	5,093.58	6,491.83	8,027.67	7,787.21	8,831.00	**7,246.26**	**8,387.39**
Dulhasti	13,711.05	15,515.91	15,228.10	15,964.03	16,081.23	**15,300.06**	**17,709.49**
Teesta-V	8,781.00	8,970.43	10,082.88	10,584.25	11,744.73	**10,032.66**	**11,612.58**
Sewa-II	4,962.87	5,408.11	6,163.45	5,523.61	7,118.86	**5,835.38**	**6,754.33**
TLDP III	5,810.13	4,911.22	6,244.94	6,936.54	7,170.97	**6,214.76**	**7,193.45**
Chamera III	7,193.80	6,774.89	6,221.38	8,776.57	8,451.08	**7,483.54**	**8,662.04**
Chutak	2,438.02	2,801.51	2,872.03	3,120.20	3,343.60	**2,915.07**	**3,374.13**
Nimmo Bazgo	719.95	2,872.43	3,387.69	3,683.29	3,874.05	**2,907.48**	**3,365.35**
Uri II	2,638.76	5,751.84	6,519.01	6,971.22	7,207.63	**5,817.69**	**6,733.85**
Parbati III	-134.90	6,222.57	6,297.64	7,140.97	7,749.11	**5,455.08**	**6,314.14**
NTPC							
Koldam	-	-	6,405.29	11,300.39	10,616.36	10,958.37	**12,080.59**

Table 25: Proposed O&M expenses for Hydro Generating Stations

(INR Lakh)

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
THDC					
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
NHPC					
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

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
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
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
NHDC					
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
SJVNL					
Naptha Jhakari	32,942.98	34,503.84	36,138.66	37,850.94	39,644.34
NTPC					
Koldam	12,652.97	13,252.48	13,880.39	14,538.06	15,226.88
NEEPCO					
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
DVC					
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

14.7.4 The Commission has observed that the Man/MW ratios of some of the hydro generating stations are high as compared to the rest of the generating stations. The Man/MW ratio of hydro generating stations for comparison purpose is shown below.

Table 26: Summary of Man/MW Ratio in Hydro Generating Stations

Generating Stations	Man/MW Ratio				
	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18
NHPC					
Bairasul	2.18	1.84	1.66	1.45	1.45
Loktak	4.10	3.65	3.22	2.83	2.83
Salal	1.19	1.14	1.07	0.96	0.96
Tanakpur	4.15	4.15	4.00	4.06	4.06
Chamera-I	0.70	0.67	0.68	0.57	0.57
Uri I	0.54	0.53	0.47	0.44	0.44
Rangit	2.60	2.53	2.48	2.32	2.32
Chamera-II	1.06	1.06	0.96	0.88	0.88
Dhauliganga	0.95	0.95	0.94	0.84	0.84
Dulhasti	1.49	1.39	1.26	1.18	1.18
Teesta-V	0.55	0.54	0.52	0.51	0.51
Sewa-II	2.32	2.18	2.01	1.67	1.67
TLDP III	1.33	1.33	1.14	0.99	0.99
Chamera III	1.29	1.12	1.07	0.96	0.96
Chutak	1.59	1.30	1.23	1.09	1.09
Nimmo Bazgo	1.64	2.20	1.62	1.47	1.47
Uri II	1.02	0.93	0.89	0.79	0.79
Parbati III	0.41	0.40	0.37	0.31	0.31
NEEPCO					
Kopili	1.29	1.21	1.13	1.01	0.92
Doyang	3.00	2.96	3.00	2.87	2.72
Omkareshwar	0.67	0.63	0.56	0.55	0.52

14.7.5 Although for the tariff period 2019-24, the Commission proposes to approve the O&M expenses norms on the basis of actual O&M expenses incurred during the past years, the Commission desires that the generating companies should rationalise the Man/MW ratios.

14.8 Proposed Provisions

14.8.1 In view of above, the Commission proposes provisions in Regulation 36 in the Draft Tariff Regulations which is reproduced below.

"36. 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)

Year	200/210/ 250 MW Series	300/330/ 350 MW Series	500 MW Series	600 MW Series	800 MW Series and above
FY 2019-20	30.59	24.22	20.38	17.39	15.65
FY 2020-21	31.57	24.99	21.03	17.94	16.15
FY 2021-22	32.58	25.79	21.71	18.52	16.66
FY 2022-23	33.62	26.62	22.40	19.11	17.20
FY 2023-24	34.69	27.47	23.12	19.72	17.75

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 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)

Year	Talcher TPS	Chandrapura TPS (Units 1 to 3), Tanda TPS, Durgapur TPS(Unit 1)
FY 2019-20 to FY 2023-24	54.78	45.35

(3) Open Cycle Gas Turbine/Combined Cycle generating stations:

(in Rs Lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines
FY 2019-20	16.24	34.38	41.00	25.00
FY 2020-21	16.76	35.48	42.31	25.80
FY 2021-22	17.30	36.62	43.66	26.63
FY 2022-23	17.85	37.79	45.06	27.48
FY 2023-24	18.42	39.00	46.50	28.35

(4) Lignite-fired generating stations:

(in Rs Lakh/MW)

Year	125 MW Sets	TPS-I of NLC
FY 2019-20	29.29	40.01
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 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)

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
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

Particulars	FY 2019-20	FY 2020-21	FY 2021-22	FY 2022-23	FY 2023-24
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 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."

15 O&M Expense – Transmission

15.1 Background

15.1.1 For working out the total allowable O&M expenses for the transmission system, the number of bays and circuit kms of line length is multiplied with the applicable O&M norms specified in terms of per bay and per km respectively.

15.1.2 The Commission, vide its Order dated 10th November, 2017, directed transmission licensees namely Power Grid Corporation of India Limited (PGCIL), Powerlinks Transmission Ltd., Jaypee Power Grid Ltd., Torrent Power Grid Pvt. Ltd., Parbati Koldam Transmission Company Ltd., East North Inter-connection Company Ltd., Jindal Power Ltd. and others to furnish details of actual performance/ operational data and O&M expenditure for the period FY 2012-13 to FY 2016-17. In response, PGCIL and Torrent Power Grid Pvt Ltd have submitted the information.

15.1.3 For tariff period 2009-14, the gradation of O&M expenses for the Sub-stations was done based on the voltage and per km basis with additional gradation based on circuit configuration for AC and HVDC lines. For the Transmission lines, gradation was done based on sub-conductor.

15.1.4 In the 2014 Tariff Regulations, O&M expenses for the transmission system have been specified on per bay basis.

15.2 Existing Provisions of the 2014 Tariff Regulations

15.2.1 Relevant provisions of the 2014 Tariff Regulations is extracted as below:-

(3) *Transmission system*

(a) The following normative operation and maintenance expenses shall be admissible for the transmission system:

Norms for sub-stations *(in Rs Lakh per bay)*	***2014-15***	***2015-16***	***2016-17***	***2017-18***	***2018-19***
765 kV	*84.42*	*87.22*	*90.12*	*93.11*	*96.20*
400 kV	*60.30*	*62.30*	*64.37*	*66.51*	*68.71*

Norms for sub-stations (*in Rs Lakh per bay*)	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**
220 kV	*42.21*	*43.61*	*45.06*	*46.55*	*48.10*
132 kV and below	*30.15*	*31.15*	*32.18*	*33.25*	*34.36*
400 kV Gas Insulated Substation	*51.54*	*53.25*	*55.02*	*56.84*	*58.73*
Norms for AC and HVDC lines (in Rs Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	*0.707*	*0.731*	*0.755*	*0.780*	*0.806*
Single Circuit (Bundled Conductor with four subconductors)	*0.606*	*0.627*	*0.647*	*0.669*	*0.691*
Single Circuit (Twin & Triple Conductor)	*0.404*	*0.418*	*0.432*	*0.446*	*0.461*
Single Circuit (Single Conductor)	*0.202*	*0.209*	*0.216*	*0.223*	*0.230*
Double Circuit (Bundled conductor with four or more sub-conductors)	*1.062*	*1.097*	*1.133*	*1.171*	*1.210*
Double Circuit (Twin & Triple Conductor)	*0.707*	*0.731*	*0.755*	*0.780*	*0.806*
Double Circuit (Single Conductor)	*0.303*	*0.313*	*0.324*	*0.334*	*0.346*
Multi Circuit (Bundled conductor with four or more sub-conductors)	*1.863*	*1.925*	*1.989*	*2.055*	*2.123*
Multi Circuit (Twin & Triple Conductor)	*1.240*	*1.282*	*1.324*	*1.368*	*1.413*
Norms for HVDC Stations					
HVDC Back–to-back stations (Rs. Lakh per 500 MW)	*578*	*627*	*679*	*736*	*797*
Rihand-Dadri HVDC bipole scheme (Rs. Lakh)	*1511*	*1637*	*1774*	*1922*	*2082*
Talcher- Kolar HVDC bipole scheme (Rs. Lakh)	*1173*	*1271*	*1378*	*1493*	*1617*

Norms for sub-stations ***(****in Rs Lakh per bay****)***	***2014-15***	***2015-16***	***2016-17***	***2017-18***	***2018-19***
Balia-Bhiwadi HVDC bipole scheme (Rs. Lakh)	*1537*	*1666*	*1805*	*1955*	*2119*

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 for 2000 MW, Talcher-Kolar 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.

(b) The total allowable operation and maintenance expenses for the transmission system shall be calculated by multiplying the number of bays and kms of line length with the applicable norms for the operation and maintenance expenses per bay and per km respectively.

(c) The operation and maintenance expenses of communication system forming part of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2008-09 to 2012-13 based on audited accounts excluding abnormal variations if any after prudence check by the Commission. The normalised O&M expenses after prudence check, for the years 2008-09 to 2012-13 shall be escalated at the rate of 3.02% for computing base year expenses for FY 2012-13 and 2013-14 and at the rate of 3.32% for escalation from 2014-15 onwards.

15.3 Issues discussed in the Consultation Paper

15.3.1 Following issues have been brought out in the Consultation paper for the tariff period commencing from 1.4.2019.

a. Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;
b. Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations;
c. Have separate norms for O&M expenses based on vintage of transmission system.

d. Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.

15.4 Stakeholders' Responses

15.4.1 In response to the issues summarised in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) One of the transmission licensee has submitted that components like variable pay (Performance Related Pay), which are an essential part of employee compensation, should be allowed and not excluded while normalizing the expenses.

b) O&M expenses may be allowed based on norms and indexed to a factor derived from CPI and WPI in ratio of 60:40. Similarly, A&G costs may be allowed based on norms and indexed to WPI. Employee costs may be indexed to CPI, R&M may be normative and linked to an index derived from CPI:WPI in ratio of 60:40 and A&G may be normative indexed to WPI.

c) Reduction of O&M expenses for additional bays/ lines will have adverse impact on the recovery of expenses and will erode the internal accruals.

d) Linking recovery of O&M expenses to MVA capacity may not allow claiming of O&M expenses for switching stations which do not have any transformer installed in it. There are only a few substations with less number of bays and high MVA capacity when compared with substations with lower MVA and higher number of bays. In case of extension of bays in any substation, without any increase in MVA capacity, which is a likely case for majority of the future projects, additional O&M expenses would be denied to the Licensee.

e) One of the State Transmission Licensee has submitted that SERCs are normally guided by CERC tariff regulations. Smaller utilities especially those working in metro cities have higher O&M cost. Therefore, special dispensation may be made for smaller utilities.. There should be no reduction in O&M in case of expansion of capacity in existing transmission substation.

f) Some stakeholders submitted that there should be rationalization and review of the multiplying factor in case of addition of bays/transformer/lines in existing stations, may be on the on the basis of MVA capacity instead of individual components or else weightage may be accorded to different components. Further, the Commission need to relook at the Compensation Allowance to ensure that licensees are not making undue profits .

g) Stakeholders also suggested that over capacity of transmission bay and incentive due to availability should be re-looked . There should also be a penalty provision, if availability of the bay falls below the 99%.

15.5 Analysis of Actual O&M Expenses

15.5.1 The actual O&M expenses as submitted by PGCIL for various regions are as under

Table 27: AC System - Actual Regional O&M expenses as submitted by PGCIL

(INR in Lakh)

Region	2013-14	2014-15	2015-16	2016-17	2017-18
NR	63,836	81,446	78,964	103,639	131,803
ER	33,423	39,756	43,182	60,673	70,825
SR	32,997	37,228	37,058	48,402	60,324
NER	14,803	17,130	19,020	27,012	29,952
WR	39,488	48,668	58,028	74,110	94,560
TOTAL	**184,547**	**224,228**	**236,252**	**313,836**	**387,464**

Table 28: HVDC System - Actual Regional O&M expenses as submitted by PGCIL

(INR in Lakh)

)Region	2013-14	2014-15	2015-16	2016-17	2017-18
NR	4,792	6,857	8,142	8,458	7,941
ER	1,853	1,620	1,828	2,875	3,685
SR	3,802	4,643	3,277	4,082	4,898
NER	-	-	958	2,399	2,502
WR	755	782	1,009	1,120	1,661
TOTAL	**11,203**	**13,901**	**15,214**	**18,934**	**20,686**

15.5.2 For normalisation of the actual O&M expenses, the Commission has factored the following expenses heads as under.

a) Electricity charges have been apportioned in the ratio of electricity consumption in the sub-station and that in the colony. Only the former have been considered for the process of normalization;
b) Security Expenses (Normal and Special) and Self Insurance reserves are not considered for arriving at norms of operation and maintenance expenses, since the same shall be allowed separately, post prudence check taking into account actual expenditure;
c) Rebate to customers, donations, ex-gratia, productivity linked incentives, performance related pay have not been considered;
d) Expenditures on Corporate Social Responsibility (CSR) has not been considered;
e) Filing fees has not been considered, since the same are being allowed separately;
f) Prior period adjustments have been excluded, as these pertain to past periods and includes expenses of the nature other than O&M expenses also.

15.5.3 The normalize O&M expenses have been worked out as follows.

Table 29: Normalised Regional O&M Expenses for PGCIL Transmission System (INR in Lakh)

Region	2013-14	2014-15	2015-16	2016-17	2017-18
NR	51,295	56,156	62,109	67,318	78,833
ER	26,083	31,326	31,006	41,026	45,261
SR	26,317	29,052	28,908	33,831	37,699
NER	12,343	13,217	13,342	16,645	17,412
WR	28,609	30,298	42,334	47,085	57,854
TOTAL	**144,648**	**160,050**	**177,699**	**205,905**	**237,059**

Table 30: Normalised O&M Expenses of Transmission System excluding HVDC stations

(INR in Lakh)

Region	2013-14	2014-15	2015-16	2016-17	2017-18
NR	47,539	51,262	55,985	61,768	73,974
ER	24,630	30,170	29,631	39,140	43,006
SR	23,337	25,738	26,443	31,153	34,702
NER	12,343	13,217	12,621	15,071	15,881
WR	28,018	29,740	41,575	46,350	56,838
TOTAL	**135,867**	**150,128**	**166,256**	**193,482**	**224,403**

15.5.4 As regards details of network parameters, since information for the period from 1st April, 2012 to 1st April, 2018 are available, average values for a year have been calculated by considering values as on the 1st day and last day of the respective year.

15.5.5 For S/c twin conductor lines, ckt-kms have been used as base and ckt-kms of all other circuit and conductor configuration have been converted to equivalent ckt-kms of S/C twin conductor ckt-km. Further, in continuation with the present approach no differentiation has been made between triple and twin conductor for same circuit configuration. Weightage factor for conversion has been used based on our estimate of ratio of O&M expenditure for a particular conductor and circuit configuration vis-à-vis S/C twin conductor. The weightage factor for a bundled conductor with four or more (Quad and Hexa) conductors is taken as 1.5 and that for single conductor it is taken as 0.5. Additionally, ratio between O&M expenditure of 1 km of D/C line is estimated to be 1.5 time that of 1 km of S/C line for single conductor and 1.75 time of 1 km of S/C for bundled conductor. The table below gives the details of ckt-km based on the gradation and equivalent S/C twin conductor ckt-km.

Table 31: Circuit Kms of AC Lines and HVDC Lines

Actual average Ckt. km in operation						Weightage Factor	Equivalent Ckt.-km (twin conductor) in operation				
Lines	**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**		**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**
S/C Hexa	-	31	62	62	228	1.500	-	46	92	92	341
S/C Quad	7,629	9,811	11,962	13,847	14,364	1.500	11,444	14,717	17,943	20,771	21,546

Actual average Ckt. km in operation						Weightage Factor	Equivalent Ckt.-km (twin conductor) in operation				
Lines	**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**		**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**
S/C Triple	2	2	2	2	2	1.000	2	2	2	2	2
S/C Twin	16,225	16,225	16,225	16,282	16,338	1.000	16,225	16,225	16,225	16,282	16,338
S/C Single	2,796	2,796	2,796	2,796	2,886	0.500	1,398	1,398	1,398	1,398	1,443
D/C Hexa	518	3,346	8,024	12,040	15,101	1.313	680	4,393	10,535	15,809	19,828
D/C Quad	14,783	16,267	18,558	21,275	24,069	1.313	19,411	21,359	24,367	27,934	31,603
D/C Triple	4,227	4,725	5,236	5,477	5,729	0.875	3,699	4,135	4,581	4,792	5,013
D/C Twin	48,920	50,082	51,697	54,295	56,960	0.875	42,805	43,822	45,235	47,508	49,840
D/C Single	8,225	8,245	8,365	8,488	8,560	0.375	3,084	3,092	3,137	3,183	3,210
M/C Quad	13	98	182	182	182	1.152	16	112	209	209	209
M/C Twin	183	183	183	239	295	0.767	140	140	140	183	226
DC on MC Quad	7	7	7	-	-	1.152	9	9	9	-	-
DC on MC twin	163	163	163	159	159	0.767	125	125	125	122	122
Total	**1,03,692**	**1,11,980**	**1,23,462**	**1,35,143**	**1,44,874**		**99,037**	**1,09,574**	**1,23,999**	**1,38,286**	**1,49,724**

15.5.6 Further, the voltage has been retained as the basis for gradation of norms for O&M expenditure for sub-station. However, bays at various voltage levels have been converted to equivalent 400 kV bays. The weightage factors for such conversion are considered in line with the approach followed in 2014 Tariff Regulations. The table below gives the details of number of bays on the gradation and equivalent 400 kV bays.

Table 32: Number of AC Substation Bays

Average No. of sub-station bays in Commercial Operation						Weightage Factor	Eq. No. of bays(400KV) in commercial operations				
Lines	**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**		**FY 14**	**FY 15**	**FY 16**	**FY 17**	**FY18**
765 kV	173	268	345	405	464	1.40	242	375	482	567	650
400 kV	1,552	1,709	1,840	1,979	2,148	1.00	1,552	1,709	1,840	1,979	2,148
220 kV	781	825	860	898	944	0.70	547	577	602	628	661
Up to 132 kV	161	167	181	189	201	0.50	80	84	90	95	101
Total	**2,667**	**2,968**	**3,225**	**3,470**	**3,757**		**2,421**	**2,744**	**3,015**	**3,268**	**3,558**

15.5.7 It has been observed that transformation capacity of AC Sub-station is highest for 765 kV. Thus, keeping 765 kV as base, weightage factor for different voltage levels has been allocated while arriving at norms. For 220 kV and 132 kV, a minimum ceiling of 50% has been considered.

Table 33: Weightage Factor for Voltage-wise Transformation capacity

Transformation capacity of AC Substation in operation	Weightage Factor Allocated
765 kV	1.00
400 kV	0.73
220 kV	0.50
132 kV	0.50

15.5.8 Normalised O&M expenses were apportioned between sub-stations and transmission lines (AC lines) in 75:25 ratio. CAGR of O&M expenses per equivalent (400 kV) AC bays for the period FY 2013-14 to FY 2017-18 works out to around 2.36%. Further, CAGR of O&M expenses per equivalent (S/C twin conductor) for the period FY 2013-14 to FY 2017-18 works out to 1.79%. Thus, by applying the same ratio of 75:25 between sub-stations and transmission lines, the effective CAGR of increase in O&M expenses for the period FY 2013-14 to FY 2017-18 works out to 2.21%.

Table 34: CAGR of increase in O&M Expenses from FY 2013-14 to FY 2017-18

Particulars	Unit	2013-14	2014-15	2015-16	2016-17	2017-18
Total Normalized O&M Expenses (A)	Rs. Lakh	135,867	150,127	166,255	193,482	224,402
Normalized O&M expenses allocated to S/S (75% of A)	Rs. Lakh	101,900	112,596	124,692	145,112	168,302
Equivalent No. of sub-station bays	No. of Bays	2421	2744	3015	3268	3558
O&M expenditure per equivalent (400 kV) AC Bay	Rs. Lakh /bay	42.09	41.04	41.36	44.40	47.30
CAGR	%	**2.36%**				
Normalized O&M expenses allocated to AC and HVDC lines (25% of A)	Rs. Lakh	33,966.81	37,531.99	41,563.88	48,370.53	56,100.65
Equivalent ckt-km in commercial operation	Ckt Km	99,037	109,574	123,999	138,286	149,724
O&M expenditure per equivalent (S/C. twin conductor) ckt-km	(Rs. Lakh /ckt-km)	0.34	0.34	0.34	0.35	0.37
CAGR	%	**1.79%**				

15.5.9 The 2014 Tariff Regulations specified transmission O&M norms for transmission lines in terms of 'per km' and for transmission substations in terms of 'per bay' basis. Accordingly, O&M expenses are allowed for transmission utilities based on the length of the transmission line as well as the number of lines/transformer bays in a transmission substation. For every km addition of transmission line and number of bays in the transmission system, the transmission licensee is entitled for incremental O&M expenses in accordance with the specified norms. The basic premise for adopting such norms linked to transmission system is to enable recovery of O&M expenses in proportion to increase in the asset base of the transmission licensee. Transformation capacity is measured in terms of MVA capacity of the transmission system. The O&M expenses for a substation and the associated asset base including bays has a significant correlation with the MVA capacity of the substation also. Therefore, the Commission is of the view that while determining O&M expenses norms for substation, MVA capacity should also be considered as a parameter besides number of bays. Accordingly, in the Draft Tariff Regulations, the Commission has proposed O&M expenses norms for substations in terms of number of bays as well as transformation capacity in MVA.

15.5.10 To arrive at O&M expenses norms per equivalent bay, per MVA and per equivalent, the normalised O&M expenses are further escalated with an escalation factor derived from CPI & WPI Indices, where the employee expenses are linked to CPI, R&M expenses are linked to WPI and A&G expenses are linked to the ratio of WPI:CPI.

15.5.11 In cases where abnormal year on year increase were observed,. the Commission, in order to normalise the same, has applied average escalation rate determined for FY 2013-14 to FY 2017-18 which works out to be 1.49% (WPI) (as per 2011-12 base year series) and 5.76% (CPI) on the corresponding expense sub-head for the immediate preceding year.

15.5.12 For all the regions of PGCIL, it is observed that the employee expenses for FY 2016-17 and 2017-18 is on a higher side due to impact of wage revision. In FY 2016-17, the pay revision impact was provided for the last quarter of the financial year (i.e. January 2017-March 2017), while during FY 2017-18, the same is provided for the entire financial year. This pay revision impact has been separated from employee expense during the respective financial year, which works out to Rs. 4.9 Lakh/bay, 0.06 Lakh/MVA and 0.08 Lakh/ckt km. The Commission shall separately approve the impact of wage revision as per the relevant provisions of Tariff Regulations.

15.5.13 Following table shows the process of arriving at the average O&M expenditure per equivalent 400 kV bay, per MVA and per equivalent ckt-km of S/C twin at 2017-18 price level. The O&M expenditure per equivalent bay, per MVA and ckt-km for FY 2013-14 to FY 2017-18 have been escalated to FY 2018-19 level with an escalation rate of 3.32% of effective CAGR. For projecting the norms for the Tariff Period 2019-2024, the escalation rate has been computed based on the five-year average of WPI for FY 2013-14 to FY 2017-18, which works out to be 1.49%, while that of CPI for the same period works out to be 5.76%. Considering the 60:40 weightage for WPI and CPI respectively, the escalation rate works out to 3.20% to arrive at norms for 2019-24.

15.5.14 The arrived normative expenses have been apportioned between sub-stations and transmission lines (AC lines) in 75:25 ratio as followed in the 2014 Tariff Regualations. Further, O&M expenses allocated for substation is proposed to be divided in ratio of 50:50 for Bays and Transformers (MVA), in absence of adequate information in this regard.

Table 35: Computation of per Bay O&M Expenses Norms for AC Substation

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18	Average
Total actual Normalized O&M Expenses (Rs. Lakh) (A)	135,867.25	150,127.94	166,255.51	193,482.11	224,402.59	
Actual Normalized O&M expenses allocated to S/S Bay (Rs. Lakh) (B)	50,950	56,298	62,346	72,556	84,151	
Equivalent No. of sub-station bays	2421	2744	3015	3268	3558	
O&M expenditure per equivalent (400 kV) AC bay (Rs. Lakh/bay)	**21.04**	**20.52**	**20.68**	**22.20**	**23.65**	**21.62**

Table 36: Computation of per MVA O&M Expenses Norms for AC Substation

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18	Average
Actual Normalized O&M expenses allocated to S/S Transformer (MVA) (Rs. Lakh)	50,950.22	56,297.98	62,345.82	72,555.79	84,150.97	

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18	Average
Capacity in MVA	1,85,343	2,18,816	2,43,279	2,72,196	3,10,353	
O&M expenditure per MVA (Rs. Lakh/MVA)	**0.27**	**0.26**	**0.26**	**0.27**	**0.27**	**0.27**

Table 37: Computation of per Ckt-km O&M Expenses Norms for AC Lines

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18	Average
Actual Normalized O&M expenses allocated to AC lines (Rs. Lakh)	33,966.81	37,531.99	41,563.88	48,370.53	56,100.65	
Equivalent ckt-km in commercial operation	99,037	109,574	123,999	138,286	149,724	
O&M expenditure per equivalent (S/C. twin conductor) ckt-km (Rs. Lakh/ckt-km)	0.34	0.34	0.34	0.35	0.37	**0.35**

15.5.15 The average O&M expenses for FY 2017-18 have been further escalated @ 3.20% per annum to reach FY 2019-20 level. The O&M expenses thus arrived for FY 2019-20 are given in Table below

Table 38: O&M Expenses Norms for AC Transmission System for Base Year

Particulars	Average FY 2017-18	Escalated @ 3.20 % to FY 2019-20 level
O&M expenditure per equivalent (400 kV) AC bay	28.15	30.02
O&M expenditure per MVA	0.34	0.36
O&M expenditure per equivalent (S/C. twin conductor) ckt-km	0.45	0.48

15.5.16 The norms for AC sub-station bays, MVA and transmission lines (AC and HVDC) for equivalent 400 kV bay, MVA and for equivalent S/C twin conductor ckt-km so arrived are then converted to various voltage levels (for sub-stations bays) MVA capacity, and various circuit and conductor configuration (for transmission lines) by applying weightage factors as stated above. The escalation rate of 3.20% per annum is applied to the norms for FY 2019-20 to arrive at norms for each year of the tariff period 2019-24.

HVDC Lines

15.5.17 The 2014 Tariff Regulations specify separate stand-alone norms for HVDC bipole projects namely Rihand-Dadri, Talcher-Kolar and Balia Bhiwadi scheme. Further, PGCIL has additionally submitted details of actual O&M expenditure for Bishwanath-Agra HVDC bipole scheme. In order to arrive at norms for HVDC stations, normalized expenses during FY 2013-14 to FY 2017-18 have been escalated @ 3.32% per annum to reach FY 2018-19 level. The average O&M expenses for FY 2018-19 level is escalated @ 3.20% per annum to reach FY 2019-20 level.

Table 39: Computation of Base Norms for HVDC Bipole Schemes

Particulars	Normalised O&M expenditure					Average (2015-16)	Escalated to 2019-20 level @ 3.20%		
HVDC Stations	2013-14	2014-15	2015-16	2016-17	2017-18		2018-19	Scheme Total	2019-20
Rihand-Dadri Scheme									
Rihand	959.43	1,430.91	1,316.32	631.59	629.56	993.56	1,095.84		
Dadri	931.19	1,335.74	1,243.22	888.38	818.43	1,043.39	1,150.80	2,246.65	2,318.55
Talcher-Kolar Scheme									
Talchar	758.81	510.00	833.74	1,250.99	1,047.71	880.25	970.87		
Kolar	1,834.23	1,316.90	1,182.62	1,266.29	1,261.97	1,372.40	1,513.68	2,484.54	2,564.06
Balia-Bhiwadi									
Bhiwadi	577.95	760.55	1,009.20	914.53	873.14	827.07	912.22		
Balia	545.03	686.99	999.56	568.10	799.94	719.92	794.03	1,706.25	1,760.86
Bishwanath-Agra									
Bishwanath	-	-	720.25	1,573.90	1,530.91	765.01	843.77		
Agra	-	-	86.46	1,328.56	596.67	402.34	443.76	1,287.52	1,328.73

15.5.18 Based on analysis, norms for HVDC stations are as below

Table 40: O&M Expenses Norms for HVDC Bipole Schemes

Norms for HVDC	2019-20	2020-21	2021-22	2022-23	2023-24
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
Bishwanath-Agra HVDC bipole scheme	1,329	1,371	1,415	1,460	1,507

15.5.19 The 2014 Tariff Regulations specify O&M expenses per 500 MW capacity of

HVDC BTB stations. In order to arrive at norms for HVDC stations, normalized expenses during FY 2013-14 to FY 2018-19 have been escalated @ 3.32% per annum to reach FY 2018-19 level. The normalized O&M expenses at FY 2018-19 level have been divided by the Station capacity (for every 500 MW) to arrive at values in Rs. Lakh/500 MW. It is observed that O&M Expenses for Gazuwaka BTB and Vindhyachal BTB for the period from FY 2013-14 to FY 2017-18 are not comparable with other BTB. Therefore, O&M expenses per 500 MW have been derived by taking average of HVDC BTB stations (excluding Gazuwaka BTB and Vindhyachal BTB) at FY 2018-19 level. It is further escalated at rate of 3.20% to arrive at norms for 2019-20.

15.5.20 Computation of base norms at FY 2018-19 price level for HVDC back to back schemes has been done as follows.

Table 41: Normalised O&M Expenses for HVDC Back to Back Schemes

(INR in Lakh)

HVDC Station	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**Average**	**2018-19**	**2019-20**
Vindhyachal BTB (2x250 MW)	742.56	679.94	1,469.60	1,218.28	716.63	965.40	-	-
Gazuwaka BTB (2x500 MW)	1,146.13	1,997.09	1,282.47	1,411.82	1,734.64	1,514.43	-	-
Chandarpur - Bhadravti BTB (2X500 MW)	591.48	557.97	758.91	734.76	743.60	677.34	**747.07**	-
Sasaram BTB (500 MW)	693.86	646.15	541.35	635.50	685.29	640.43	**706.36**	-
Average of Chandarpur - Bhadravti and Sasaram BTB	**-**	**-**	**-**	**-**	**-**	**-**	**726.71**	**749.97**

15.5.21 Computation of base norms at FY 2018-19 price level for HVDC back to back schemes has been done as follows.

Table 42: O&M Expense Norms for HVDC Back to Back Schemes

(INR in Lakh)

Norms for HVDC	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**
HVDC Back–to-back stations (Rs. Lakh per 500 MW)	750	774	799	824	851

15.5.22 The O&M expenses for the GIS bays and transformers shall be allowed as worked out by multiplying by a factor of 0.70 of the normative O&M

expenses for bays and transformers.

Communication Systems

15.5.23 The norms for communication systems shall be based on length of OPGW link (in km), number of remote terminal units (in number) and number of PMU (in number).

15.5.24 To arrive at norms, 70% of total O&M expenses for communication systems is allocated to OPGW links, 15 % to RTUs and 15% to PMUs respectively.

15.5.25 For normalising the O&M expenses, following exclusions have been considered.

i. Security Expenses (Normal and Special) and Self Insurance reserve have been excluded, since the same shall be allowed separately after prudence check.

ii. Rebate to Customers, Donations, Ex-gratia, Productivity Linked Incentives, Performance Related Pay have not been considered.

iii. Expenditure on Corporate Social Responsibility (CSR) have not been considered.

iv. Filing fees has not been considered, since the same are being allowed separately.

v. Prior period adjustments have been excluded, as these pertain to past periods and includes expenses of the nature other than O&M expenses also.

15.5.26 For normalizing abnormal variations in the actual O&M expenses of communication systems, the Commission has applied average escalation rate determined for FY 2013-14 to FY 2017-18 which works out to be 1.49% (WPI) (as per 2011-12 base year) and 5.76% (CPI) on the corresponding expense heads for the immediate preceding year. The normalised O&M expenses are as under.

Table 43: Normalised O&M Expenses for Communication System

(INR in Lakh)

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18
NR	368.30	298.21	69.36	106.45	241.36
ER	1000.83	846.94	810.22	827.78	578.96
WR	235.93	179.57	206.20	354.93	405.11
SR	375.20	334.10	516.88	523.49	761.83

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18
NER	344.30	333.53	305.28	317.04	288.79
Total	**2324.55**	**1992.35**	**1907.94**	**2129.69**	**2276.04**

15.5.27 Out of total O&M expense for communication systems 70% of the normalised expense is allocated to length of OPGW, 15% of the normalised expense is allocated to number of RTUs and remaining 15% of the normalised expense is allocated to number of PMU installed in the region, as highlighted earlier. Accordingly, the O&M expenses norms for communication system is worked out as under.

Table 44: Normalised O&M Expense Norms for Communication System

Particulars	2013-14	2014-15	2015-16	2016-17	2017-18
Total Normalized O&M Expenses (Rs. Lakh) (A)	2324.55	1992.35	1907.94	2129.69	2276.04
OPGW					
Actual Normalized O&M expenses allocated to OPGW (70% of A) (Rs. Lakh) (B)	1627.19	1394.64	1335.56	1490.78	1593.23
Average length of OPGW links in operation	9141.55	11969.31	17991.18	24244.35	30615.90
O&M expenditure per km OPGW (Rs. Lakh/km)	0.18	0.12	0.07	0.06	0.05
RTU					
Actual Normalized O&M expenses allocated to RTUs 15% of A) (Rs. Lakh) (B)	348.68	298.85	286.19	319.45	341.41
Number of Remote Terminal Units(RTUs)	160.00	160.00	161.00	162.00	160.00
O&M expenditure per RTU (Rs. Lakh/ RTU)	2.18	1.87	1.78	1.97	2.13
PMU					
Actual Normalized O&M expenses allocated to PMU 15% of A) (Rs. Lakh) (B)	348.68	298.85	286.19	319.45	341.41
Number of PMU	24.00	34.00	167.00	526.00	1214.00
O&M expenditure per PMU (Rs. Lakh/PMU)	14.53	8.79	1.71	0.61	0.28

15.5.28 The O&M expenditure per OPGW, per RTU and per PMU unit for FY 2013-14 to FY 2017-18 have been escalated to FY 2018-19 level at the escalation rate of effective CAGR of O&M expenses of 3.32%. For the purpose of arriving at norms, the O&M expenditure for 2018-19 have been escalated @ 3.20% to reach FY 2019-20 level.

15.6 Proposed Provisions

15.6.1 In view of above, the Commission proposes provisions in Regulation 35 in the Draft Tariff Regulations which is reproduced as under.

"35. Operation and Maintenance Expenses:

……….

(3) Transmission system: (a) The following normative operation and maintenance expenses shall be admissible for the transmission system:

Particulars	2019-20	2020-21	2021-22	2022-23	2023-24
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 conductor with four or more sub-conductors)	1.268	1.309	1.351	1.394	1.439
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

Particulars	2019-20	2020-21	2021-22	2022-23	2023-24
Bhiwadi-Balia HVDC bipole scheme	1,761	1,817	1,875	1,935	1,997
Bishwanath-Agra HVDC bipole scheme	1,329	1,371	1,415	1,460	1,507

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 per km respectively.

(4) Communication system: (a) The following norms shall be applicable for calculation of operation and maintenance expenses for the communication system:

(in Rs. Lakh per Unit)

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

(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 the operation and maintenance expenses as specified above.

(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 further 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."

16 Normative PAF for Thermal Generating Stations

16.1 Background

16.1.1 The plant availability factor of a generating station is the percentage of time, it is available to provide energy to the grid. The availability of a plant is the factor of its reliability and the periodic maintenance it requires. The Commission in the 2001 Tariff Regulations, and 2004 Tariff Regulations specified separate norms to be achieved for recovery of full AFCs and in order to qualify to receive incentive in case the station performs above such specified norm. However, the Commission in the 2009 Tariff Regulations changed the norm and specified single norm (except for few stations) as target availability for recovery of full fixed charges and incentives. To be eligible for incentives, a separate norm, i.e., Plant Load factor (PLF) was prescribed for the generating stations in the 2014 Tariff Regulations. The generating station was allowed incentive only in the case when it generated power in excess of target PLF.

16.2 Existing Provisions of the 2014 Tariff Regulations

*"**36**. The norms of operation as given hereunder shall apply to thermal generating stations:*

(A) Normative Annual Plant Availability Factor (NAPAF)

(a) All thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 85%

Provided that in view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the NAPAF for recovery of fixed charges shall be 83% till the same is reviewed.

The above provision shall be reviewed based on actual feedback after 3 years from 01.04.2014.

(b) Following Lignite-fired Thermal generating stations of Neyveli Lignite Corporation Ltd:

TPS-I	*72%*
TPS-II Stage I & II	*75%*

TPS-I (Expansion)	*80%*

(c) *Following Thermal Generating Stations of DVC:*

Bokaro TPS	*75%*
Chandrapura TPS	*75%*
Durgapur TPS	*74%*

(d) Following Gas based Thermal Generating Stations of NEEPCO:

Assam GPS	*72%*

(e) Lignite fired Generating Stations using Circulatory Fluidized Bed Combustion (CFBC) Technology and Generating stations based on coal rejects

1. First Three years from COD – 75%

2. For next year after completion of three years of COD – 80%

(B) Normative Annual Plant Load Factor (NAPLF) 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%*
TPS – II Stage I &II	*80%*
TPS- I (Expansion)	*80%*

(c) For following Thermal Generating Stations of Damodar Valley Corporation (DVC):

Bokaro TPS	*80%*
Chandrapur TPS	*80%*
Durgapur TPS	*80%*

16.3 Issues discussed in the Consultation Paper

16.3.1 The Consultation Paper highlighted the following key issues with regard to Normative Annual Plant Availability Factor:

(a) In Control Period 2014-19, the recovery of fixed charges was linked to availability. The availability of 85% was specified, with exceptions for some specific plants. The existing availability norms are uniform for all the generating stations. Now with the increased private participation, access to imported fuel by private developers and technological improvement, different availability norms for existing and new plants can be contemplated.

(b) As Shortage of domestic fuel affects availability of the plants and their scheduling, the existing norm for availability may require review. In the event of using e-auction or imported coal (other than fuel arrangement agreed in purchase agreement), the issue of need of prior consent of beneficiary, maximum permissible limit of blending also need to be deliberated.

(c) As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There are possibilities of declaring lower availability during the peak demand period and higher availability during low demand period, thereby achieving the target cumulative availability on annual basis though beneficiaries may not be getting electricity when required. In case of partly tied up capacity, the plant availability factor for whole plant may not be relevant.

(d) In The existing norms of annual plant availability may need review, considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly.

16.4 Stakeholders' Response

16.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions on various issues:

a) Few Central sector generating companies suggested that a power generating company has no control over companies supply coal or railways and therefore, loss of Plant Availability Factor (PAF) due to shortage of coal should be considered in recovery of fixed charge.

b) Few Central sector generating companies submitted that, if target availability is set on monthly/quarterly basis, stations having two units of similar size may not be able to go for over hauls (major or minor) of unit, since there will be under recovery of fixed charges due to reduced availability in the month/ quarter.

c) Few Central gas based generating companies submitted that analysis of fuel supply constraints be conducted and relief in NAPAF to such plants struggling with fuel constraints may be allowed.

d) Few of the State sector companies suggested that generator uses the excess declaration made during the low demand period to compensate the lower declaration during high load period to ensure availability, which needs to be addressed.

e) Some Discoms suggested that payment of fixed charges should be done based on some weighted average of demand availability during peak and off peak period. In the event plant is not able to declare availability during peak hours, its availability during off peak hours should be adjusted suitably.

f) Some private stakeholders suggested that while scheduling, there is a need to clearly define the controllable and uncontrollable factors for availability. The generating stations shouldn't get penalised for non-availability on account of uncontrollable factors.

16.5 Actual Availability of Generating Station

16.5.1 The Commission has reviewed the suggestions and comments received from various stakeholders and sought the actual data for FY 2012-13 to FY 2016-17 from central generating stations to assess actual performance vis-à-vis norms. The actual availability achieved by the generating stations for FY 2012-13 to FY 2016-17 is given in the Table below.

Table 45: Actual Average PAF of NTPC Stations

Generating Station	Station Type	2012-13	2013-14	2014-15	2015-16	2016-17	5- Year Avg.
Badarpur Thermal Power Station	Non Pithead	91.91	91.28	87.03	93.27	93.79	**91.46**
Dadri Thermal Power Station Stage-I	Non Pithead	98.24	99.69	99.88	98.41	105.40	**100.32**
Dadri Thermal Power Station Stage-II	Non Pithead	91.75	103.09	89.02	103.10	98.85	**97.16**
Farakka STPS Stage-I&II	Non Pithead	73.38	92.65	84.92	81.29	87.09	**83.87**
Farakka STPS Stage-III	Non Pithead	70.65	86.84	84.64	81.64	98.04	**84.36**
Kahalgaon STPS Stage-I	Pithead	85.61	94.58	92.02	90.23	94.76	**91.44**
Kahalgaon STPS Stage-II	Pithead	75.05	88.96	87.60	93.72	93.01	**87.67**
Korba STPS Stage-I&II	Pithead	90.97	95.31	88.11	90.46	91.82	**91.33**
Korba STPS Stage-III	Pithead	94.76	92.00	89.62	88.66	99.73	**92.95**
Ramagundam STPS Stage-I&II	Non Pithead	93.41	89.30	92.10	93.96	94.58	**92.67**
Ramagundam STPS Stage-III	Non Pithead	87.05	98.39	94.16	100.68	91.62	**94.38**
Rihand STPS Stage-I	Pithead	82.00	94.38	83.74	85.44	81.42	**85.40**
Rihand STPS Stage-II	Pithead	100.94	91.70	88.19	92.66	98.97	**94.49**
Rihand STPS Stage-III	Pithead	62.65	90.386	83.42	85.74	94.18	**83.27**
Simhadri STPS Stage-I	Non Pithead	87.74	89.06	93.73	94.05	94.69	**91.85**
Simhadri STPS Stage-II	Non Pithead	75.42	85.89	90.50	95.86	96.22	**88.78**
Singrauli STPS Stage- I&II	Pithead	94.05	94.45	83.73	94.62	89.44	**91.26**
Sipat STPS Stage-I	Pithead	80.54	89.62	89.03	87.85	92.92	**87.99**
Sipat STPS Stage-II	Pithead	85.69	94.52	90.55	96.13	96.18	**92.61**
Talcher STPS Stage- I	Pithead	81.93	86.11	86.03	90.64	87.86	**86.52**
Talcher STPS Stage- II	Pithead	82.87	85.17	92.95	93.30	90.10	**88.88**
Talcher TPS	Pithead	95.84	94.56	93.29	92.79	93.05	**93.91**
Tanda TPS	Non Pithead	84.46	95.16	89.56	94.63	94.60	**91.68**
Unchahar Thermal Power Station Stage-I	Non Pithead	98.79	99.63	95.55	98.08	90.51	**96.51**
Unchahar Thermal Power Station Stage-II	Non Pithead	100.07	100.22	96.02	101.12	100.00	**99.49**
Unchahar Thermal Power Station Stage-III	Non Pithead	100.06	97.09	102.56	95.61	105.12	**100.09**
Vindhayanchal Stage I	Pithead	93.97	94.00	86.80	91.88	93.80	92.09
Vindhayanchal Stage II	Pithead	94.17	95.00	85.11	88.39	86.91	89.92
Vindhayanchal Stage III	Pithead	98.97	98.66	88.18	93.59	95.07	94.90

Table 46: Actual Average PAF of DVC Stations

Generating Station	2012-13	2013-14	2014-15	2015-16	2016-17	5- Year Avg.
Bokaro TPS	65.03	69.62	58.09	60.16	78.09	**66.20**
Chandrapura TPS (Unit 1-3)	61.57	69.75	55.21	79.73	78.08	**68.87**
Chandrapura TPS (Unit 7-8)	88.80	83.52	77.86	70.24	91.87	**82.46**
Durgapur Steel TPS	69.30	76.48	57.02	58.10	90.60	**70.30**
Durgapur TPS	75.85	87.41	64.25	61.77	52.86	**68.43**
Koderma TPS	-	71.41	25.68	40.35	49.91	**46.84**

Note- Mejia Station data not available

Table 47: Actual Average PAF of NLC Stations

Generating Station	2012-13	2013-14	2014-15	2015-16	2016-17	5- Year Avg
NLC TPS-1	75.75	77.74	67.74	58.92	71.39	**70.31**
NLC TPS-1 EXP	90.73	91.37	92.58	90.31	94.61	**91.92**
NLC TPS-2 stage 1	86.35	88.95	87.78	85.97	92.12	**86.35**
NLC TPS-2 stage 2	87.69	89.17	87.17	83.11	90.27	**87.48**
NLC TPS-2 EXP	NA	NA	NA	19.39	30.93	**25.16**
Barsingsar Thermal Power Station	87.69	89.17	87.17	83.11	90.27	**87.48**

Table 48: Actual Average PAF of Gas Based Stations

Generating Station	2012-13	2013-14	2014-15	2015-16	2016-17	5- Year Avg
NTPC						
Anta	93.62	98.34	94.19	94.95	93.52	**94.93**
Auraya	91.56	98.12	88.48	97.65	97.48	**94.66**
Gandhar	94.55	97.31	93.3	98.58	97.55	**96.26**
Kawas	92.65	90.46	93.57	99.87	96.55	**94.62**
Faridabad	94.55	97.31	93.3	98.58	97.55	**96.26**
Dadri Gas	97.67	97.46	95.97	98.11	90.12	**95.87**
KayamKulam	90.98	92.17	90.26	87.35	88.83	**89.92**
NEEPCO						
Assam Gas	66.47	68.61	69.38	70.16	62.07	**67.34**
Agartala gas	85.53	86.72	84.64	81.40	83.05	**84.27**

16.6 Commission's Proposal

16.6.1 As can be seen, the average availability during FY 2012-13 to FY 2016-17 for most of the station of NTPC was above 90%, with few stations in the range of 85% to 90% and only one stations i.e. Farakka had NAPAF of less than 85%. In case of stations like Rihand III and Mauda STPS Stage I, which have achieved commercial operation during the Control Period FY 2014-19, the actual average availability was less than the norms. However, in these stations, the availability has improved gradually post commercial operations. For 29 NTPC Coal based plants (excluding Mauda STPS Stage I), the average availability factor works out to 91.63% and the median works out to 91.57% with standard deviation of 4.81% which means availability factor of the plant varies from 96.39% and 86.75%. In view of above, the Commission proposes to fix the Normative Annual Availability Factor of generating stations at 83% on quarterly basis.

16.6.2 For DVC stations, the actual performance levels were lower than the norms specified- Bokaro TPS (66.2%), Durgapur TPS (68.43%) , Chandrapura TPS (Unit 1-3) (68.87%) and Chandrapura TPS (Unit 7-8) (82.46%). The average availability of Koderma TPS which was commissioned in June 2014 and Durgapur Steel TPS which was commissioned in March 2013 were 48.84% and 70.30% respectively. In view of above, the Commission proposes to retain the relaxed norms for DVC stations were in the 2014 Tariff Regulations i.e. Bokaro TPS at 75%, Chandrapura TPS at 75% and Durgapur TPS at 74% . All the normative availability parameters specified above shall be applicable on quarterly basis.

16.6.3 The Commission observes that for NLC, the availability of the stations is more than the norms, except in case of NLC TPS – I . The target availability for the station was 72%,and the five-year average is only 70.31 %, All other stations have achieved the specified target availability by 10% or more as specified in the 2014 Tariff Regulations. For Barsingsar Thermal Power Station the average five year PAF is 87.48%. Accordingly, the Commission proposes to retain target availability norm for NLC TPS-1 as specified in 2014 Tariff Regulations and revises the target availability norm for NLC TPS-2 (Stage 1 and Stage 2) and TPS-1 expansion to 85%. The normative availability parameters specified above shall be applicable on quarterly basis.

16.6.4 For gas based generating stations of NTPC, all the stations have achieved target availability ,the five-year average actual availability being close to 95%. Therefore, the Commission proposes to retain the same level of target availability for the next control period i.e. 2019-24 also. The normative availability parameters specified above shall be applicable on quarterly basis.

16.6.5 For NEEPCO's Assam Gas Stations, the actual five-year average availability is 67.34%,compared to the target availability of 72%, For Agartala Gas station, the actual five-year average availability is 84.27%, slightly lower than the target norm of 85%. The Commission proposes to retain the Target availability norm for Assam Gas Station at 72% and retain the norms for Agartala Gas Station as per existing provisions of 2014 Tariff Regulations. The normative availability factor specified above shall be on quarterly basis.

16.6.6 The Commission proposes norms for recovery of full fixed charges linked to the target availability on quarterly basis, above which, incentive shall be applicable.

16.6.7 The Commission notes that the existing target availability norm of 85%, includes the margin required for scheduled or planned outages required for annual inspection and maintenance of the generating station. Now with the normative target availability being proposed to be met on quarterly basis, as against annual basis, the thermal generating stations may not get sufficient time for annual inspection and maintenance within a quarter. However, as per definition of availability, the actual annual plant availability factor of the thermal generating station is to be calculated taking into account all planned, scheduled, forced outages. This shall be addressed at the time of finalisation of Tariff Regulations.

16.7 Proposed Provisions

16.7.1 In view of above, the Commission proposes provisions in Regulation 59 of the Draft Tariff Regulations is reproduced as below:-

"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.

(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 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%
Durgapur TPS	80%

"

17 Gross Station Heat Rate

17.1 Background

17.1.1 The heat rate is the amount of energy required by an electrical generator or a power plant to produce one-kilowatt hour (kWh) of electricity. If the heat rate is low, the efficiency is higher. The Commission in the 2001 Tariff Regulations had approved single norm for existing as well as new 200 MW and 500 MW units for all central generating stations and provide relaxed norms for new thermal stations during the stabilization period. In the 2004 Tariff Regulations, the Commission specified separate norms for 200 MW and 500 MW. For 200 MW units, the Commission retained the same norms while for 500 MW units, the norms were slightly tightened, as these units are more efficient resulting in lower SHR. In the 2009 Tariff Regulations, the Commission retained the norms for 200 MW and tightened the norms for 500 MW and provided a relaxation of 6.5% for new thermal generating stations, which have achieved COD on or after 1 April2009. In the 2014 Tariff Regulations, the Commission tightened the norms for both 200 MW and 500 MW and reduced the relaxation to 4.5 % from 6.5% for new thermal generating stations.

17.2 Existing Provisions of the 2014 Tariff Regulations

"(C) Gross Station Heat Rate

(a) Existing Thermal Generating Station

(i) Existing Coal-based Thermal Generating Stations, other than those covered under clauses (ii) and (iii) below:

200/210/250 MW Sets	***500 MW Sets (Sub-critical)***
2450 kCal/kWh	*2375 kCal/kWh*

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.

(ii) Following Thermal generating stations of NTPC Ltd:

Badarpur TPS	*2750kCal/kWh*
Talcher TPS	*2850kCal/kWh*
Tanda TPS	*2750kCal/kWh*

(iii) Thermal Generating Stations of DVC:

Bokaro TPS	*2700kCal/kWh*
Chandrapura TPS (Unit 1 to 3)	*3100 kCal/kWh*
Durgapur TPS	*2820 kCal/kWh*

(iv) Lignite-fired Thermal Generating Stations:

For lignite-fired thermal generating stations, except for TPS-I and TPS-II (Stage I & II) of Neyveli Lignite Corporation 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

(d) 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 Neyveli Lignite Corporation Ltd:

TPS-I : 4000 kCal/kWh

TPS-II : 2900 kCal/kWh

TPS- I (Expansion): 2750 kCal/kWh

(vi) Open Cycle Gas Turbine/Combined Cycle generating stations:

Existing generating stations of NTPC Ltd and NEEPCO

Name of generating station	Combined cycle (kCal/kWh)	Open Cycle (kCal/kWh)
Gandhar GPS	2040	2960
Kawas GPS	2050	3010
Anta GPS	2075	3010
Dadri GPS	2000	3010
Auraiya GPS	2100	3045
Faridabad GPS	1975	2900
Kayamkulam GPS	2000	2900
Assam GPS	2500	3440
Agartala GPS	-	3700
Sugen	1850	2685
Ratnagiri	1850	2685

(b) New Thermal Generating Station achieving COD on or after 1.4.2014

(i) Coal-based and lignite-fired Thermal Generating Stations

= 1.045 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	170	170	247
SHT/RHT (0C)	535/535	537/537	537/565	565/593
Type of Boiler Feed Pump (BFP)	Electrical Driven	Turbine Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935	1850
Min. Boiler Efficiency				

Sub-Bituminous Indian Coal	*0.86*	*0.86*	*0.86*	*0.86*
Bituminous Imported Coal	*0.89*	*0.89*	*0.89*	*0.89*
Max Design Unit Heat Rate (kCal/kWh)				
Sub-Bituminous Indian Coal	*2273*	*2267*	*2250*	*2151*
Bituminous Imported Coal	*2197*	*2191*	*2174*	*2078*

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 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 1.4.2014, the Heat Rate Norms for those generating units as well as generating units declared under commercial operation on or after 1.4.2014 shall be lower of the Heat Rate Norms arrived at by above methodology and the norms as per the regulation 36(C)(a)(i):

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 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 BFP.*

(c) ***Thermal Generating Station having COD on or after 1.4.2009 till 31.03.2014***

(i) Coal-based and lignite-fired Thermal Generating Stations

= 1.045 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 Heat Rate Norms computed as per above shall be limited to the Heat Rate Norms approved during FY 2009-10 to FY 2013-14.

(d) Gas-based / Liquid-based thermal generating unit(s)/ block(s) having COD on or after 01.04.2009.

= 1.05 X Design Heat Rate of the unit/block for Natural Gas and RLNG (kCal/kWh)

= 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:

Provided that the Heat Rate Norms computed as per above shall be limited to the Heat Rate Norms approved during FY 2009-10 to FY 2013-14."

17.3 Issues discussed in the Consultation Paper

17.3.1 The Consultation Paper highlighted following key issues with regard to Station Heat Rate, on which comments had been sought from stakeholders.

a) The heat rate is a crucial parameter as it has substantial impact on tariff. The gain/savings on account of heat rate are to be shared with the beneficiaries. Therefore, heat rate is required to be specified giving due consideration to all relevant factors including shortage of domestic coal supply in the country. The Heat Rate Norms would be required to be seen in the light of efficiency improvement targets achieved by the generating stations under the PAT scheme. The Heat Rate Norms varies with the passage of useful life of the project due to degradation and therefore, the norms specified based on the recently commissioned plants may not be attainable by older plants.

b) The existing regulations provides for calculation of Gross Station Heat rate for new stations based on Design Heat Rate with margin of 4.5%. This margin specified for gross station heat rate is based on recommendation of the Central Electricity Authority.

c) Determination of station heat rate may require specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.

17.4 Stakeholders' Response

17.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions. Few Central Generating companies suggested that due to integration of renewable energy and low PLF due to surrender of power by beneficiaries and shortage of coal, the generating station, often have to run at the Technical minimum level or sometimes even lower than that. Therefore, design heat rate increases by 5% to 6%.

a) A Central Generating Companies submitted that for 500 MW units SHR of 2400 kcal/unit and for 200/210/250 MW units SHR of 2475 kcal/unit may be considered as most of the units are not able to meet the present norm. For gas based stations, the norms are too stringent, which are not achievable.

b) Few of the State sector companies suggested that Station Heat Rate (SHR) should be determined based on Turbine Heat Rate, Boiler Efficiency and related heat losses and not on the prevailing practice of determination of Station Heat Rate (SHR), based on historical data, furnished by Generators.

c) Some State sector companies observed that the Commission has rightly captured the need to consider the make, unit size, vintage and heat rate degradation to specify operating norms. But Data for more than 5 years and from wider cross section of plants, not restricting to NTPC should be considered for arriving at standard norms.

d) Some Discoms suggested to notify different station Heat Rate Norms for older and newer plants.

e) Some Discoms submitted that Station Heat Rate determined in the existing Tariff Regulations have been attained by most of generating stations. Therefore, it is suggested that the existing norms may be retained for the coal/lignite based generating stations

f) Some private stakeholders suggested that determination of Station Heat Rate may be based on various factors like continuous partial loading, age of plant, low calorific value of supplied gas & insufficient fuel supply.

17.5 Actual Gross Station Heat Rate

17.5.1 The Commission has reviewed the suggestions and comments received from various stakeholders. The Commission had sought the actual data for FY 2012-13 to FY 2016-17 from Central Generating Stations to assess actual performance vis-a-vis norms. The actual Station Heat Rate achieved by the generating stations for FY 2012-13 to FY 2016-17 after taking into account the compensation factor allowed for lower loading factor in accordance with the provisions of Grid Code, is given in the table below.

Table 49: Actual Gross SHR (kCal/kWh) for Coal based Generation Stations

Generating Stations		FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Five Year Average
200 MW Series							
Dadri Stage-I	Greater Than 10 Years	2,398	2,343	2,353	2,265	2,307	2333
Kahalgaon-I		2,367	2,370	2,367	2,372	2,397	2375
Unchahar-I		2,408	2,419	2,364	2,381	2,373	2389
Unchahar-II		2,403	2,414	2,363	2,377	2,393	2390
Unchahar-III		2,402	2,356	2,412	2,324	2,388	2376
Vindhyachal-I		2,409	2,403	2,404	2,411	2,479	2421
Average		**2,398**	**2,384**	**2,377**	**2,355**	**2,390**	**2381**
500 MW Series							
Dadri Stage-II	Less than 10 Years	2,359	2,386	2,335	2,336	2,328	2349
Farraka Stage-III		2,380	2,346	2,332	2,329	2,404	2358
Kahalgaon-II		2,322	2,322	2,327	2,326	2,364	2332
Korba Stage-III		2,374	2,355	2,346	2,343	2,368	2357
Rihand-III		2,371	2,337	2,348	2,325	2,365	2349
Simhadri-II		2,355	2,330	2,313	2,333	2,352	2337
Sipat -II		2,336	2,353	2,325	2,356	2,342	2342
Vindhyachal-IV		2,406	2,328	2,305	2,311	2,358	2342
Average		**2363**	**2345**	**2329**	**2332**	**2360**	**2346**
500 MW Series							
Ramagundam- III	Greater than 10 Years	2,365	2,360	2,356	2,358	2,324	2352
Simhadri-I		2,357	2,359	2,350	2,357	2,369	2358

Generating Stations		FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Five Year Average
Rihand-I		2,351	2,341	2,365	2,330	2,369	2351
Rihand-II		2,284	2,350	2,326	2,329	2,368	2332
Vindhyachal-II		2,350	2,352	2,360	2,363	2,423	2370
Vindhyachal-III		2,345	2,347	2,320	2,327	2,369	2341
Average		**2,342**	**2,352**	**2,346**	**2,344**	**2,370**	**2,351**

17.5.2 Actual Gross Station Heat Rate (kCal/kWh) for Talcher and Tanda TPP are shown as under:

Table 50: Actual Gross SHR (kCal/kWh) for Talcher and Tanda Stations

Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year avg
Talcher TPP	2,823	2,810	2,796	2,819	2,829	2,815
Tanda TPP	2,760	2,788	2,783	2,747	2,778	2,771

17.5.3 Actual Gross Station Heat Rate (kCal/kWh) for coal and lignite based stations of NLC India Ltd are as under.

Table 51: Actual Gross SHR (kCal/kWh) for Lignite based Generating Stations

Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year avg
TPS -1	3,897	3,902	3,944	4,116	4,039	3,980
TPS -1 EXP	2,738	2,694	2,685	2,691	2,687	2,699
TPS - 2 Stage 1	2,875	2,862	2,843	2,862	2,862	2,861
TPS - 2 Stage 2	2,871	2,856	2,844	2,863	2,865	2,860
TPS - 2 Exp	-	-	-	3,278	3,178	3,228
Barsingsar TPP	2,600	2,696	2,597	2,562	2,547	2,601

17.5.4 Actual Gross Station Heat Rate (kCal/kWh) for gas based stations of NTPC and NEEPCO other than small gas turbine stations are as under.

Table 52: Actual Gross SHR (kCal/kWh) for Gas based Generating Stations

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year avg
NTPC						
Anta GPS	2,080	2,052	2,073	2,117	2,091	2,082
Auraiya GPS	2,105	2,091	2,113	2,123	2,144	2,115
Kawas GPP	2,038	2,072	2,043	2,065	2,012	2,046
Faridabad GPP	1,989	1,971	1,963	1,989	1,993	1,981
Dadri GPP	2,005	1,997	2,008	2,031	2,039	2,016
Kayamkulam GPP	1,965	1,960	1,991	1,994	2,011	1,984
NEEPCO						
Assam GPS	2,817	2,817	2,666	2,674	2,514	2,698
Agartala GPS	3,813	3,825	3,811	2,770	2,512	2,641

Note : Gandhar GPP Data are required to be validated and Same will be considered on receipt of correct date from NTPC Ltd.

17.5.5 Actual Gross Station Heat Rate (kCal/kWh) for Advance F Class machines of Sugen and RGPPL are as under

Table 53: Actual Gross SHR (kCal/kWh) for Advance F Class Machines

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year avg
Sugen	1,709	1,735	1,714	1,710	1,714	1,716
RGPPL	1,801	1,803	-	1,824	1,843	1,818

17.5.6 It is observed that actual SHR of all the above coal- based stations of NTPC are below the normative SHR, except in Farakka TPP, Tal Kaniha TPP, Tanda TPP and Mauda. For NLC stations, the actual five-year average heat rate is slightly less than the current Heat Rate Norms, except for Barsingsar TPP.

17.5.7 For Agartala and Assam GPS, the actual five-year average heat rate has been considerably higher than the norm. However, the heat rate achieved by other stations are within the deviation of 1to2% from the norms.

17.6 Commission's Proposal

17.6.1 The Commission reviewed the suggestions and comments received from various stakeholders, who have mainly suggested that Station Heat Rate norms should reflect the current level of operational efficiency, considering possible improvement that can be achieved during the next control period i.e. 2019-24. The Tariff Policy, 2016 provides that,

"f) Operating Norms

Suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.11(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.

The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission. The SERC would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission, or phase them out in accordance with the norms specified by the Authority in this regard.

…...

17.6.2 The Commission has been following the consistent practice of formulating norms based on actual data of the past period. The Commission, therefore, is of the opinion that the norm should be based on the actual data for the past five years with appropriate margin and taking into consideration CEA recommendations..

17.6.3 From the actual heat rate data for the generating stations, it is observed that almost all the coal based generating stations of NTPC, except Farakka TPP, Tal Kaniha TPP, Tanda TPP and Mauda, have achieved heat rate lower than the approved norms as per the 2014 Tariff Regulations. While due to integration of renewable, the Plant Load factor of coal based thermal stations are going down, but the generating station are compensated by relaxation given in the Grid Code.

17.6.4 The Commission observes that all 200 MW stations which are more than ten years in operations, have achieved heat rate lower than the approved norms as per the 2014 Tariff Regulations.. As the five-year average works out to be 2381 kCal/kWh, taking correction factor into account as per Grid Code the Commission proposes the Heat Rate Norms for 200 MW series units at 2410 kCal/kWh.

17.6.5 500 MW series stations are segregated as per their vintage i.e. plants less than ten years old and plants which are more than ten years old. The actual heat rate data shows that SHR of almost all the coal based generating stations of NTPC is 2346 kCal/kWh for plants less than ten years old and 2351 kCal/kWh for plants more than ten years old. Therefore, the Commission proposes to retain the Heat Rate Norms for 500 MW series units to 2,375 kCal/kWh same as previous Tariff Regulation.

17.6.6 The Commission had approved relaxed norms for some of the generating stations after taking due consideration of plant vintage. In case of Tanda

TPS, the Commission had approved a norm of 2,750 kCal/kWh whereas the five-year average heat rate achieved by the station was 2,771 kCal/kWh. The Commission proposes to retain the Heat Rate norms for Tanda at the same level as in the 2014 Tariff Regulations.

17.6.7 With regards to Talcher TPS, the Commission had approved a heat rate of 2,850 kCal/kWh whereas the five-year average heat rate achieved by the station was 2,815 kCal/kWh. The Commission proposes Heat Rate norms for Talcher TPS to 2830 kCal/kWh.

17.6.8 As the data provided by DVC is not complete and sufficient, the Commission proposes to accept the recommendation submitted by CEA on operation norms for thermal generating station vide letter no CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018.

Table 54: Gross SHR (kCal/kWh) for DVC Generating Stations

Generating Stations	Proposed Norms
Bokaro TPS	2,700 kCal/kWh
Chandrapura TPS (Unit 1 to 3)	3,000 kCal/kWh
Durgapur TPS	2,750 kCal/kWh

17.6.9 NLC TPS- I station is the oldest station of NLC and due to the vintage of this station, relaxed heat rate was approved. The actual five-year average heat rate of 3,980 kCal/kWh achieved by the station is slightly less than the current norm of 4,000 kCal/kWh approved in the 2014 Tariff Regulations. The recommendation of CEA on operation norms for thermal generating station vide letter no CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018 suggest a heat rate of 4,000 kCal/kWh. Therefore, the Commission proposes Heat Rate norms for NLC TPS – 1 at 4000 kCal/kWh.

17.6.10 For NLC TPS-1 expansion, the actual five-year average heat rate is 2,699 kCal/kWh, which is considerably less than the current Heat Rate Norms approved in the 2014 Tariff Regulations i.e. 2750 kCal/kWh. In all the five years NLC TPS-1 expansion was able to achieve heat rate of less than 2,700 kCal/kWh. The recommendation of CEA on operation norms for thermal generating station vide letter no CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018 suggests a heat rate of 2720 Kcal for NLC TPS-1 expansion. The Commission proposes to revise the norm for NLC TPS-1 to 2,720 kCal/kWh.

17.6.11 For NLC TPS – II Stage 1 & 2,the actual five-year average is 2860 kCal/kWh & 2861kCal/kWh, respectively and are less than the current heat rate norm approved in the Tariff Regulation, 2014 i.e. 2900 kCal/kWh. The recommendation of CEA on operation norms for thermal generating station vide letter no CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018 suggest heat rate norms of 2890 kCal/kWh for NLC TPS - II. Therefore, The Commission proposes the Heat rate norm of NLC TPS – II at 2890 kCal/kWh.

17.6.12 In the Draft Tariff Regulations, the norms of Heat Rate in respect of NLC TPS-I(expansion) and NLC TPS-II have been inadvertently mentioned as 2750 kCal/kWh and 2720 kCal/kWh instead of 2720 kCal/kWh and 2890 kCal/kWh respectively. This error shall be addressed suitably at the time of finalisation of Draft Tariff Regulations.

17.6.13 For gas based generating station, analysis of the actual data as submitted by the generating stations have been done. Five-year average of NTPC Gas power stations is within the same range of as per norms given in the 2014, Tariff Regulations. The Commission therefore, proposes to retain the norms for NTPC Gas Power Stations at the same level as in the 2014 Tariff Regulations. The gas turbines for Sugen and Ratnagiri are advanced class 9F machines and therefore, their actual heat rates should be in the similar ranges. But the data of Sugen as furnished by them are much lower than the data of Ratnagiri and are even lower than designed heat rate. Subsequently, it has been represented by the Sugen Power vide letter dated 20th December, 2018 that their plant is commissioned on 15th August, 2009 and accordingly, the station heat rate is to be worked out based on design heat rate. This may be reviewed at the time of finalisation.

17.6.14 For Assam Gas power plant the actual heat rate is 2698 kCal/kWh as compared to the norms of 2500 kCal/kWh in the 2014 Tariff Regulations. Agartala Gas Turbine Power Project was converted to a Combined Cycle Power Plant with the addition of two Steam Turbine Generating units (STG) comprising of a capacity of 25.5 MW each with effect from 29.7.2015 and 1.9.2015 respectively. Current norms specified by the Commission in Order No. 94/GT/2016 dated 14.07.2017 is 2534 Kcal/kWh. Therefore, Commission proposes the Heat Rate norm for Agartala and Assam Gas Turbine Power Project at 2600 kCal/kWh.

17.6.15 With regards to gas/liquid based thermal generating station, the Commission proposes to retain the current norms as per the 2014 Tariff Regulations for the new generating stations.

17.6.16 The following table summarises the computation of actual Operating Margin for 500 MW Series thermal generating stations commissioned after 01.04.2009.

Table 55: Operating Margin for 500 MW Series Generating Stations

Generating Stations	Boiler Efficiency considered (%)	Turbine HR (kcal/ kwh)	Design Heat Rate (kcal/ kwh)	Average of Corrected SHR (2016-17 and 2017-18)	Actual Operating Margin
500 MW Series					
Kahalgaon-II	86.00	1,944	2,260	2,393	5.54%
Korba-III	86.00	1,945	2,262	2,368	4.49%
Mauda-I	86.00	1,932	2,297	2,401	6.43%
Rihand-III	86.00	1,932	2,299	2,365	5.01%
Simhadri-II	86.00	1,933	2,287	2,381	5.61%
Sipat-II	86.00	1,948	2,269	2,342	3.27%
Vindhyachal-IV	86.00	1.932	2,300	2,405	6.58%
				Average	**5.28%**

17.6.17 The Commission observe that in case of Kahalgaon II Power Station which comprises of three units of 500 MW, the design turbine cycle heat rate is 1944 kCal/kWh for Stage II. Further, the boiler efficiency for stage II is taken as 86.00%. The Design heat rate, works out to around 2260kCal/kWh for stage II. By considering the current norm of 4.5% margin above the design heat rate, this results in a heat rate of 2361 kCal/kWh for Stage II. However, the actual five-year average heat rate for the station works out to be 2393 kCal/kWh. Similar is the case with other units. The Commission, therefore, proposes to slightly normalise the norms to reflect the current operational efficiencies of the stations by increasing the margin to 5.00% from the current level of 4.50%.

17.6.18 Further, for new generating stations based on coal rejects, the Commission proposes to apply the above norms. However, for such generating stations, the design heat rate shall be approved by the Commission on case to case basis.

17.6.19 The Commission proposes a margin of 5.0% over and above design heat rate to be allowed for Thermal Generating Station having COD on or after 1.4.2009.

17.7 Proposed Provisions

59. The Commission proposes provisions in Regulations 59 in the Draft Tariff Regulations which is reproduced below.

"**Norms of Operation for thermal generating stations:**

(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:

200/210/250 MW Sets	**500 MW Sets (Sub-critical)**
2,410 kCal/kWh	2,375 kCal/kWh

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

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 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): 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 cycle (kCal/kWh)	Open Cycle (kCal/kWh)
Gandhar GPS	2,040	2,960

Name of generating station	Combined cycle (kCal/kWh)	Open Cycle (kCal/kWh)
Kawas GPS	2,050	3,010
Anta GPS	2,075	3,010
Dadri GPS	2,000	3,010
Auraiya GPS	2,100	3,045
Faridabad GPS	1,975	2,900
Kayamkulam GPS	2,000	2,900
Assam GPS	2,600	3,578
Agartala GPS	2,600	3,578
Sugen	1,760	2,554
Ratnagiri	1,820	2,641

(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 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	170	170
SHT/RHT (^{0}C)	535/535	537/537	537/565
Type of BFP	Electrical Driven	Turbine Driven	Turbine Driven
Max Turbine Heat Rate (kCal/kWh)	1955	1950	1935
Min. Boiler Efficiency			
Sub-Bituminous Indian Coal	0.86	0.86	0.86
Bituminous Imported Coal	0.89	0.89	0.89
Sub-Bituminous Indian Coal	2273	2267	2250

Bituminous Imported Coal	2197	2191	2174

Pressure Rating (Kg/cm2)	247	247	270	270
SHT/RHT (^{0}C)	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 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 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."

18 Secondary Fuel Oil Consumption

18.1 Background

18.1.1 Under the 2014 Tariff Regulations, the cost of Secondary Fuel oil consumption is made as part of the Energy Charge whereas norms are defined as ml/kWh.

18.1.2 In 2004 Tariff Regulations, the Commission specified separate norms for coal fired stations and lignite fired stations. Norms for all coal-based thermal power generating stations during stabilization period was 4.5 ml/kWh and for subsequent period it was fixed at 2.0 ml/kWh.

18.1.3 For Lignite Fired Generating stations, during stabilization period it was 5.0 ml/kWh and during subsequent period it was 3.0 ml/kWh.

18.1.4 In the 2009Tariff Regulations, norms for Secondary Fuel Oil Consumption were 1.25 ml/KWh for lignite based CFBC technology and 1.0 ml/kWh for Coal based project, with the provision for sharing of savings with the beneficiaries.

18.2 Existing Provisions of the 2014 Tariff Regulations

18.2.1 The existing norms for the Secondary Fuel Oil Consumption is as below

"36. The norms of operation as given hereunder shall apply to thermal generating stations:

…….

(D) Secondary fuel oil consumption

(a) Coal-based generating stations other than at (c) below: 0.50 ml/kWh

(b) (i) Lignite-fired generating stations except stations based on CFBC technology and TPS-I : 2ml/kWh

(ii) TPS-I : 1.5ml/kWh

(iii) Lignite-fired generating stations based on CFBC Technology: 1.00ml/kWh

(c) Coal-based generating stations of DVC:

Mejia TPS Unit – I to IV	*1.0 ml/kWh*
Bokaro TPS	*1.5 ml/kWh*
Chandrapur TPS	*1.5 ml/kWh*
Durgapur TPS	*2.4 ml/kWh*

(d) Generating Stations based on Coal Rejects: 2 ml/kWh

18.3 Issues discussed in the Consultation Paper

18.3.1 Following issues had been brought out in the Consultation paper for the tariff period commencing from 1.4.2019:

"Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations."

18.4 Stakeholders' Responses

18.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) One Central Sector Stakeholder has submitted that normative value as specified below may be considered:

- For 600 MW/500 MW/ 250 MW: 1.0 ml/kWh
- For 210 MW: 1.5 ml/kWh

b) One Central Sector Stakeholder has submitted that relaxation of specific fuel oil consumption of 0.75 ml/kwh in case of Farakka and Mauda may be considered, instead of 0.5 ml/kwh for specific stations

c) One Central Sector Stakeholder has submitted that present practice of SFC for Lignite based power plants need to continue. Increased SFC due to partial loading owing to frequent ramp up and ramp down/ renewable penetration may be allowed.

d) One State Stakeholder has submitted that the impact of low PLF on operating norms is provided in IEGC 4^{th} amendment. The commission may consider pass through of higher parameters under tariff.

e) Some Beneficiaries have submitted that reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions.

f) Some Beneficiaries have submitted that keeping in view of continuous start/stops of units due to cyclic power demand, Specific fuel oil consumption may be relaxed depending upon no of start stops due to back down.

g) One Beneficiaries has suggested for separate benchmarking of operational parameters such as specific secondary fuel oil consumption in accordance with the consumption pattern of last 10 years for power plants based on different technologies.

h) One Beneficiaries has suggested Norms for consumption of secondary fuel oil may be define considering plant having normal operations and plants having supply & operations at lower PLF up to the technical minimum.

i) The existing level of 0.50 ml/kWh in respect of coal fired thermal power stations may be retained. For Lignite fired stations the existing SFC of 2.0 ml/kWh may be reduced to 1.5 ml/kWh in respect of all lignite fired thermal power stations.

j) One Private Stakeholder has submitted that the norms of 0.5 ml/kwh does not capture the consumption of fuel related to frequent start-stop or higher oil consumption at low PLF. Grid Code provides for compensation of start-stop only after 7 operations. Therefore, SFOC norms may be increased to 1 ml/ kwh.

k) Some Private Stakeholders have proposed to increase the normative for SFO consumption to 0.75 ml/kWh in the view of the following: Cyclic scheduling being provided by the Discoms to the generating stations to absorb the intermittency of the renewable.

l) Some Private Stakeholders and Private Organizations have submitted that considering the frequent start /stop operations there is a need to increase the normative SFC to at least 1 ml/kw from the existing level.

18.5 Actual Secondary Fuel Oil Consumption

18.5.1 The actual secondary fuel oil consumption for various generating stations is as shown below:

Table 56: Actual Secondary Fuel Oil Consumption for Thermal Stations

Generating Stations	Existing Norm (ml/kWh)	2012-13	2013-14	2014-15	2015-16	2016-17	Five year Average
NTPC							
Badarpur	0.50	1.51	1.13	0.91	0.63	0.50	0.94
Barh	0.50			1.13	0.65	0.88	0.89
Bongaigaon	0.50					4.34	4.34
Dadri Stage I	0.50	0.16	0.23	0.12	0.37	0.35	0.25
Dadri Stage II	0.50	0.28	0.15	0.23	0.21	0.23	0.22
Farakka Stage I & II	0.50	0.96	0.59	0.88	1.76	0.87	1.01
Farakka Stage III	0.50	2.91	0.79	0.91	1.59	0.22	1.28
Kahalgaon Stage I	0.50	0.70	0.67	0.26	0.54	0.44	0.52
Kahalgaon Stage II	0.50	0.70	0.67	0.26	0.54	0.44	0.52
Korba Stage I & II	0.50	0.09	0.10	0.18	0.25	0.25	0.18
Korba Stage III	0.50	0.14	0.14	0.11	0.20	0.11	0.14
Mauda	0.50	106.72	21.86	4.16	1.83	0.62	27.04
Ramagundam Stage I & II	0.50	0.19	0.29	0.25	0.21	0.25	0.24
Ramagundam Stage III	0.50	0.36	0.11	0.13	0.05	0.27	0.18
Rihand Stage I	0.50	0.56	0.33	0.46	0.39	0.58	0.46
Rihand Stage II	0.50	0.15	0.32	0.22	0.22	0.12	0.21
Rihand Stage III	0.50	3.25	0.75	0.63	0.26	0.26	1.03
Simadhri Stage I	0.50	0.24	0.27	0.20	0.16	0.27	0.23
Simadhri Stage II	0.50	0.70	0.18	0.26	0.23	0.17	0.31
Singrauli Stage I & II	0.50	0.21	0.25	0.46	0.39	0.45	0.35
Sipat Stage I	0.50	0.63	0.27	0.13	0.30	0.15	0.30
Sipat Stage II	0.50	0.31	0.19	0.17	0.17	0.14	0.20
Talcher STPS Stage I	0.50	1.15	0.54	0.55	0.46	0.50	0.64
Talcher STPS Stage II	0.50	0.31	0.27	0.26	0.30	0.31	0.29
Talcher TPS	0.50	0.38	0.40	0.40	0.38	0.32	0.38
Tanda	0.50	0.59	0.42	0.39	0.32	0.44	0.43
Unchahar Stage I	0.50	0.58	0.38	0.47	0.29	0.28	0.40
Unchahar Stage II	0.50	0.23	0.36	0.46	0.21	0.17	0.29
Unchahar Stage III	0.50	0.40	0.46	0.20	0.28	0.04	0.28
Vindhyachal Stage I	0.50	0.25	0.25	0.37	0.34	0.73	0.39
Vindhyachal Stage II	0.50	0.12	0.16	0.32	0.42	0.48	0.30
Vindhyachal Stage III	0.50	0.12	0.08	0.23	0.26	0.41	0.22

Generating Stations	Existing Norm (ml/kWh)	2012-13	2013-14	2014-15	2015-16	2016-17	Five year Average
Vindhyachal Stage IV	0.50	11.73	0.54	0.40	0.35	0.52	2.71
Vindhyachal Stage V	0.50	-	-	-	1.45	0.72	1.08
NLC India							
TPS 1	1.50	1.22	0.99	1.78	2.86	2.23	1.82
TPSII-Stage 1	2.00	0.48	0.36	0.41	0.79	0.48	0.51
TPSII-Stage 2	2.00	0.49	0.37	0.64	1.20	0.82	0.70
TPS-I-Exp	2.00	0.69	0.87	0.67	0.75	0.55	0.71
TPS-II-Exp	1.00				10.19	3.76	6.97
Barsingsar TPS	1.00	0.56	0.77	0.63	0.99	0.77	0.75

*DVC has not submitted the actual data

18.5.2 The Commission, in 2014-19, has specified a specific secondary fuel oil consumption norm of 0.5ml/kWh. However, almost all the stations of NTPC, except Badarpur, Barh, Bongaigaon, Farakka Stage 1 to 3, Rihand III, and Vindhyachal Stage V, have been able to achieve SFOC below 0.5 ml/kWh.

18.5.3 With regard to lignite fired stations for TPS-I, it is observed that actual five year average secondary fuel consumption works out to around 1.82 ml/kWh. The Commission, therefore, proposes to retain the current norm of 1.50 ml/kWh. For Lignite fired stations except stations based on CFBC technology, the Commission has proposed to revise the current norm of 2 ml/kWh to 1 ml/kWh, as the five year average is less than 1 ml/kWh for all the stations. Also for stations based on CFBC technology, the current norm is proposed to be continued, as five year actual average value for the stations have been lower than the norms. Further, in case of DVC stations, the Commission has proposed to retain the existing norms.

18.6 Proposed Provisions

59. The Commission proposes provisions in Regulations 59 in the Draft Tariff Regulations which is reproduced below.

Norms of Operation for thermal generating stations::

(D) Secondary fuel oil consumption:

(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

19 Auxiliary Energy Consumption

19.1 Background

19.1.1 In thermal power plant, a fraction of power produced is consumed by the power generating equipment and their auxiliaries such as fans, motors etc. In the 2001 Tariff Regulations, the Commission separated norms for 200 MW and 500 MW series and for units with and without cooling tower. For 500 MW series, the Commission specified separate norms for electric BFP and steam driven BFP. Further, the Commission prescribed an additional 0.50% Actual Auxiliary Energy Consumption (AEC) for units under stabilization. These norms are applicable to coal, lignite fired station and for gas based station. Additionally, the Commission specified separate norms for Open Cycle and Combined Cycle Operations.

19.1.2 The Commission in the 2004 Tariff Regulations, stipulated separate norms for coal and lignite based stations. Further, the Commission also specified relaxed norms for Talcher and Tanda TPS taking cognisance of smaller sized units and vintage of these stations. In case of lignite fired stations of NLC, the Commission except for TPS-I (210 MW) and TPS-II (210 MW) specified additional 0.50% over and above, allowed for coal fired stations as auxiliary consumption. The Commission for TPS-I and TPS-II of NLC specified relaxed norms taking cognisance of unit sizes and vintage of the units.

19.1.3 The Commission in the 2009 Tariff Regulations retained the norms for 200 MW and 500 MW. However, the Commission in the 2009 Tariff Regulations did not specify separate norms for stabilization period. In the 2014 Tariff Regulations, the Commission retained the norms for 200 MW series but tightened the norms for 500 MW series.

19.2 Existing Provisions of the 2014 Tariff Regulations

(E) Auxiliary Energy Consumption:

(a) Coal-based generating stations except at (b) below:

With Natural Draft cooling tower or without cooling tower

(i) 200 MW series - 8.5%

(ii) 300/330/350/500 MW and above

Steam driven boiler feed pumps	-	*5.25%*
Electrically driven boiler feed pumps	-	*7.75%*

Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%:

Provided also that Additional AEC as follows may be allowed for plants with Dry Cooling Systems:

Type of Dry Cooling System	*(% of gross generation)*
Direct cooling air cooled condensers with mechanical draft fans	*1%*
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	*0.5%*

(b) Other Coal-based generating stations:

(i) Talcher Thermal Power Station	*: 10.50%*
(ii) Tanda Thermal Power Station	*: 12.00%*
(iii) Badarpur Thermal Power Station	*: 8.50%*
(iv) Bokaro Thermal Power Station	*: 10.25%*
(v) Chandrapur Thermal Power Station	*: 9.50%*
(vi) Durgapur Thermal Power Station	*: 10.50%*

(c) Gas Turbine /Combined Cycle generating stations:

(i) Combined Cycle	*: 2.5%*
(ii) Open Cycle	*: 1.0%*

(d) Lignite-fired thermal generating stations:

(i) 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 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) Barsingsar Generating station of NLC using CFBC technology: 11.50%

(iii) TPS-I, TPS-I (Expansion) and TPS-II Stage-I&II of Neyveli Lignite Corporation Ltd.:

TPS-I	*12.00%*
TPS-II	*10.00%*
TPS-I (Expansion)	*8.50%*

(iv) Lime stone consumption for lignite-based generating station using CFBC technology:

Barsingsar	*: 0.056 kg/kWh*
TPS-II (Expansion)	*: 0.046 kg/kWh*

(e) Generating Stations based on coal rejects: 10%

19.3 Issues discussed in the Consultation Paper

19.3.1 The Consultation Paper highlighted key issues on which comments were sought from stakeholders.

a) The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0- 2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption.

b) Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale.

c) Generating stations which have less auxiliary consumption than the norms, are able to declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a part of auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration.

19.4 Stakeholders' Response

19.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions. Few Central Generating companies suggested that the present APC norms of coal stations be increased by 0.75 % and additional 2% APC provided for stations where emission control system is commissioned. Separate norms for Tanda and Talcher needs to be continued.

a) A State Generating Companies submitted that due to frequent start and stop, partial load operation and prolonged backing down the auxiliary consumption of the station has gone up. This is attributed to unproductive part of auxiliary during frequent start and stop, part load operation in prolonged partial/full back down. Therefore, unproductive part of such auxiliary power consumption needs to be given separate treatment while arriving normative auxiliary consumption for the plant.

b) Few of the state sector companies suggested that in case of full back down of the plant/station/ module, there is no provisions and source identified for required auxiliary consumption scheduling in existing Grid Code Regulation - 2010. The auxiliary consumption of the stations even in total back down and plant shut down runs in MWs. Therefore, suitable provision for these needs is required to be made.

c) Some state sector companies suggested that the Commission has rightly captured the need to consider make, unit size, vintage and heat rate degradation to specify operating norms. More than 5 years' data from wider cross section of plants not restricted to NTPC, should be considered for arriving standardised norms.

d) Some Discoms suggested that auxiliary consumptions treatment should be based on normative availability to share the benefit of new technology with the Discoms. Some Discoms submitted that there should be separate norms for different size of the Units, further as colony consumption does not form part of the auxiliary system of the power plant,. inclusion of colony consumption in the AEC reduces the efficiency of the generator.

e) Some private stakeholders suggested that performance of generating stations will be affected in coming years as unit loading is expected to be low in view of the inadequate fuel availability, lower demand/schedule by customers and ageing of units. All these aspects should be considered, which will warrant a higher AEC norm for generating stations.

19.5 Actual Auxiliary Energy Consumption (AEC)

19.5.1 The actual AEC for Coal based stations of NTPC from FY 2012-13 to FY 2016-17, considering correction factor as per Grid Code are summarised below.

Table 57: Actual Auxiliary Energy Consumption for NTPC Generating Stations

Generating Stations	Vintage	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year Average	Existing Norms
200 MW Motor Driven IDCT								
Kahalgaon-I	**Greater Than 10 Years**	9.98%	9.96%	9.65%	9.50%	9.71%	9.76%	9.00%
Unchahar-I		8.14%	8.61%	8.56%	8.83%	9.14%	8.66%	9.00%
Unchahar-II		8.64%	9.25%	9.21%	9.39%	8.97%	9.09%	9.00%
Unchahar-III		8.02%	8.56%	8.55%	8.62%	8.80%	8.51%	9.00%
Vindhyachal-I		7.84%	8.10%	8.26%	8.83%	9.15%	8.43%	9.00%
200 MW Motor Driven NDCT								
Dadri Stage-I		7.61%	7.74%	7.94%	8.09%	8.44%	7.97%	8.50%
500 MW Steam Driven IDCT								
Farraka Stage-III	**Less Than 10 Years**	5.38%	5.35%	5.33%	6.14%	6.20%	5.68%	5.75%
Kahalgaon-II		6.29%	6.37%	5.85%	5.47%	5.14%	5.83%	5.75%
Korba Stage-III		5.36%	5.50%	5.74%	5.61%	5.73%	5.59%	5.75%
Rihand-III		6.93%	5.89%	5.93%	5.44%	5.55%	5.95%	5.75%
Sipat -II		6.29%	5.99%	5.53%	5.51%	5.40%	5.75%	5.75%
Vindhyachal-IV		-	5.55%	5.51%	5.59%	5.85%	5.63%	5.75%
Ramakundam- III	**Greater Than 10**	4.98%	5.10%	4.83%	5.45%	5.26%	5.12%	5.75%

Generating Stations	Vintage	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year Average	Existing Norms
Rihand-II	Years	5.86%	5.66%	5.47%	5.59%	5.55%	5.63%	5.75%
Vindhyachal-II		5.96%	5.80%	5.95%	5.98%	6.33%	6.01%	5.75%
Vindhyachal-III		4.93%	4.94%	5.28%	5.73%	5.67%	5.31%	5.75%
500 MW Steam Driven NDCT								
Dadri Stage-II	Less than 10 Years	5.80%	5.82%	5.00%	4.93%	4.92%	5.29%	5.25%
Simhadri-II		5.90%	5.66%	5.47%	5.59%	5.53%	5.63%	5.25%
Simhadri-I	Greater than 10 years	5.96%	5.85%	5.46%	5.51%	5.40%	5.64%	5.25%
500 MW Motor Driven								
Rihand-I	Greater than 10 Years	7.41%	7.95%	7.80%	8.09%	8.41%	7.93%	**7.75%**

19.5.2 The actual AEC for Talcher and Tanda generating stations of NTPC from FY 2012-13 to FY 2016-17,are summarised below.

Table 58: Actual AEC for Talcher and Tanda Generating Stations

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year Average
Talcher TPP	10.50%	10.52%	10.61%	10.67%	10.65%	10.59%
Tanda TPP	12.02%	11.89%	11.46%	11.62%	11.47%	11.69%

19.5.3 Most of the NTPC stations were able to achieve the Auxiliary Energy Consumption within some deviations from the norms of Tariff Regulations, 2014.

19.5.4 The actual AEC for Lignite based generating stations of NLC India Ltd. from FY 2012-13 to FY 2016-17, are summarised below.

Table 59: Actual Auxiliary Energy Consumption for NLC Generating Stations

Generating Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	5 Year Average
TPS -1	11.55%	11.42%	12.07%	12.15%	11.89%	11.82%
TPS -1 EXP	8.56%	8.46%	8.21%	8.20%	8.45%	8.38%
TPS - 2 Stage 1	9.67%	9.54%	9.58%	9.72%	9.78%	9.66%
TPS - 2 Stage 2	9.66%	9.67%	9.61%	9.85%	9.51%	9.66%
TPS - 2 Exp	-	-	-	22.68%	17.84%	20.26%
Barsingsar TPP	12.68%	12.61%	13.51%	13.94%	12.87%	13.12%

19.5.5 In case of NLC, the actual AEC for the stations are almost at the level of current norms, except in case of Barsingsar TPP, where the actual five-year average AEC works out to around 13.12%, as against the norm of 11.50% specified by the Commission in Tariff Regulations, 2014.

19.5.6 The AEC for Gas based generating stations (other than small gas turbine stations) of NTPC and NEEPCO from FY 2012-13 to FY 2016-17, are summarised below.

Table 60: Actual AEC for Gas based Generating Stations

Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Existing Norms	5 Year Average
NTPC							
Anta GPS	**2.36%**	**2.31%**	2.34%	3.22%	3.70%	**3.00%**	**2.78%**
Auraiya GPS	2.96%	3.46%	3.21%	2.86%	4.32%	**3.00%**	**3.36%**
Kawas GPP	2.17%	2.93%	2.54%	2.90%	2.49%	**3.00%**	**2.61%**
Gandhar GPP	2.54%	2.84%	2.73%	2.83%	2.82%	**3.00%**	**2.75%**
Faridabad GPP	2.54%	2.84%	2.73%	2.83%	2.82%	**3.00%**	**2.75%**
Dadri GPP	2.40%	2.50%	2.68%	2.50%	2.65%	**3.00%**	**2.55%**
Kayamkulam GPP	2.60%	2.84%	3.12%	7.48%	32.67%	**3.00%**	**9.74%**
NEEPCO							
Assam GPS	2.68%	2.13%	2.47%	2.49%	2.51%	**3.00%**	**2.46%**
Agartala GPS	1.72%	1.54%	1.74%	3.05%	3.10%	**1.00%**	**2.23%**

19.5.7 For NTPC gas based stations, the actual AEC works out to around 2.55% - 3.36% as against the current norm of 2.50%, except for Kayamkulam GPP where Auxiliary Energy Consumption has increased significantly because of low PLF. For Assam GPS, the actual five-year average Auxiliary Energy Consumption has been at par with the norms. The Agartala GPS was converted to a Combined Cycle Power Plant with the addition of two Steam Turbine Generating units (STG) comprising of a capacity of 25.5 MW each with effect from 29.7.2015 and 1.9.2015, respectively. Therefore, the AEC has been at par with AEC norms for closed cycle Gas Power Plant.

19.5.8 There seems to be discrepancy with respect to data pertaining to AEC submitted by DVC. Therefore, the Commission has not considered the same for analysis.

19.6 Commission's Proposal

19.6.1 After examining and reviewing the comments/suggestions of stakeholders, the Commission has proposed as follows.

a) The Commission proposes to set norms on the basis of past five-year actual data. It is observed that most of the NTPC stations have achieved Auxiliary energy consumption, within some deviations from the weighted average norm, of Tariff Regulation 2014. NTPC Stations have been categorised as per vintage of the station, capacity and technology used.

b) In case of 200 MW series stations all stations, those which are in operation for more than ten years and Dadri stage- I station have Natural Draft Cooling Tower(NDCT) while other stations have Induced Draft Cooling Tower (IDCT).However, most of the stations have been able to achieve norms, within some deviations than the norms of the Tariff Regulation 2014. Considering recommendation of CEA vide Letter No. CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018 and data provided by generation companies, the Commission proposes Auxiliary Energy Consumption norms for 200 MW unit series at 8.50%.

c) In case of 500 MW steam driven series, few stations are in operation for more than ten years. In case of Natural Draft Cooling Tower, Dadri stage II and Simadri II are in operation for less than ten years and Simadri I is in operation for more than ten years. Five-years average of AEC of these stations are 5.29%, 5.63% and 5.64%, respectively considering correction factor as per IEGC Regulation. Considering recommendation of CEA vide Letter No. CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018 and data provided by generation companies, the Commission proposes Auxiliary Energy Consumption norms for 500 MW unit series for NDCT at 5.75%.

d) In case of 500 MW steam driven IDCT series, few stations are in operation for more than ten years. Most of the generating stations are able to achieve norms with marginal deviations. Therefore, the Commission proposes that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%.

e) In case of 500 MW motor driven NDCT series, only one station is in operation for more than ten years. Its five year average of AEC works out to 7.93%, against the present norms, as per Tariff Regulation 2014 of 7.75%. Therefore, the commission proposes, for 500 MW series thermal generating stations with motor driven Boiler feed pump, Auxiliary Energy Consumption norms at 8.00%.

f) Talcher is able to achieve the Auxiliary Energy Consumption norms. Therefore the Commission proposes to retain the norms specified for these station as specified in Tariff Regulation 2014. Tanda's five-year average of Auxiliary Energy Consumption is 11.69%,but in the last three years, Tanda was able to achieve norms of 11.46%, 11.62% and 11.47%, respectively. Therefore, the Commission has proposed Auxiliary Energy Consumption norm for Tanda at 11.50%.

g) In case of NLC TPS I, NLC TPS II and NLC TPS I Expansion, Auxiliary Energy Consumption norms are close to the norms specified in Tariff Regulation 2014-19. Therefore, the Commission proposes to retain the Auxiliary Energy Consumption norms for NLC TPS I, NLC TPS II and NLC TPS I Expansion at the same level as specified in Tariff Regulation 2014-19.

h) Further, the actual auxiliary consumption are close to the current norms for all the stations of NLC except for Barsingsar TPP, where the actual five-year average Auxiliary Energy Consumption works out to around 13.12% against the norm of 11.50%. Barsingsar is not able to achieve Auxiliary Energy Norms even for a single year. Therefore, the Commission proposes to relax the Auxiliary Energy Consumption norm to 12.50%.

i) As data provided by DVC were not correct, the Commission proposes to accept recommendation of CEA vide Letter No. CEA/TETD-TT/2018/N-15/1451 dated 10/12/2018, which proposes to retain the norms for Bokaro Thermal Power Station, Chandrapur Thermal Power Station and Durgapur Thermal Power Station. Therefore, the Commission proposes to retain the Auxiliary Energy Consumption norms for these Stations.

j) With regards to gas based generating stations, the Commission proposes to relax the earlier norm at 2.50% for Combined Cycle. For Open Cycle, the Commission proposes to retain the norm at 1%. For NTPC gas based stations, the actual auxiliary consumption varies between 2.55% to 3.36% as against the current norm of 2.50%. The average of Auxiliary Energy Consumption of all NTPC Gas based stations is 2.80%, except for Kayakulam GPP where Auxiliary Energy Consumption has increased significantly because of low PLF. Therefore, the Commission proposes Auxiliary Energy Consumption norms of 2.75% for Combined Cycle gas based generating stations.

k) For Assam GPS, the actual five-year average Auxiliary Energy Consumption has been at par with the norms. However, Agartala GPS was converted to a Combined Cycle Power Plant with the addition of two Steam Turbine Generating units (STG) comprising of a capacity of 25.5 MW each with effect from 29.7.2015 and 1.9.2015 respectively. Thereafter, the Auxiliary Energy Consumption is at par with Auxiliary Energy Consumption norms for Combine Cycle Gas Power Plant.

l) For colony consumption, the Commission proposes that the same shall not form a part of auxiliary consumption as the same doesn't form part of auxiliary system of the power plant.

The Commission proposes that the generator should be allowed to declare higher availability if it is able to operate at lower than normative aux power. Due to the efficiency of a generator it may be able to sell extra power in exchange or to a third party.

19.7 Proposed Provisions

19.7.1 The Commission proposes provisions in Regulations 59 in the Draft Tariff Regulations which is reproduced below.

"59.

….

Norms of Operation for thermal generating stations:

(E) Auxiliary Energy Consumption

(a) For Coal-based generating stations except at (b) below:

S. No.	Generating Station	With Natural Draft cooling tower or without cooling tower
(i)	200 MW series	8.50%
(ii)	300/330/350/500 MW series	
	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:

Type of Dry Cooling System	**(% of gross generation)**
Direct cooling air cooled condensers with mechanical draft fans	1.0%
Indirect cooling system employing jet condensers with pressure recovery turbine and natural draft tower	0.5%

(b) For Other Coal-based generating stations:

(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 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%"

20 Norms for Operation for Hydro Generating Stations

20.1 Background

20.1.1 Specifying operating norms and periodic monitoring of the same of any generating station is key to assess its efficiency and performance over the entire Tariff Control Period. In case of hydro generating stations, the operating norms are more specific based on the type, technology and size of the power plant.

20.1.2 In the 2001 Tariff Regulations, the Commission approved three types of operating norms for hydro generating stations, namely, Normative Capacity Index, Auxiliary Consumption and Transformation Losses. In the 2004 Tariff Regulations, the Commission implemented Capacity Index Mechanism as a measure of plant availability, based on the premise that the hydrology risk is required to be borne by the beneficiaries only. In the 2009 Tariff Regulations, the Commission replaced Capacity Index Mechanism with the concept of NAPAF, with the premise of equally sharing the hydrological risk between the generating company and the beneficiaries. Further, case specific revisions in Operating Norms were also allowed for few hydro generating stations. In the 2014 Tariff Regulations, the Operational Norms for hydro generating stations continue to include the norms for Auxiliary Consumption, Transformation Losses and NAPAF.

20.2 Existing Provisions of the 2014 Tariff Regulations

20.2.1 The existing 2014 Tariff Regulations notified by the Commission consists of the following provision regarding Operational Norms for Hydro Generating Stations are as under:

*"**37. Norms of operation for hydro generating stations:** (1) The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:*

(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%.

(d) 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.

(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:

Station	**Type of Plant**	**Plant Capacity No. of Units X MW**	**NAPAF (%)**
NHPC			
Chamera – 1	Pondage	3 X 180	90
Bairasul	Pondage	3 X 60	90
Loktak	Storage	3 X 35	85
Chamera-II	Pondage	3 X 100	90
Chamera – III	Pondage	3 X 77	85
Rangit	Pondage	3 X 20	90
Dhauliganga	Pondage	4 X 70	90
Teesta – V	Pondage	3 X 170	85
Dulhasti	Pondage	3 x 130	90
Salal	ROR	6 x 115	60
Sewa–II	Pondage	3 X 40	85
Uri	ROR	4 X 120	70
Tanakpur	ROR	3 X 31.4	55
Chutak	ROR	4 X 11	50
Nimoo Bazgo	Pondage	3 X 15	65
Teesta Low Dam Project -III	Pondage	4 X 33	85
Uri-II	Pondage	4 X 60	55
NHDC			
Indirasagar	Storage	8 X 125	85
Omkareshwar	Pondage	8 X 65	90
THDC			

Station	Type of Plant	Plant Capacity No. of Units X MW	NAPAF (%)
Tehri	Storage	4 X 250	77
Koteshwar	Storage	4 X 100	67
SJVNL			
NathpaJhakri	Pondage	6 X 250	90
NEEPCO			
Kopili Stg – 1	Storage	4 X 50	79
Khandong	Storage	2 X 25	69
Kopili Stg. – 2	Storage	1 X 25	69
Doyang	Storage	3 X 25	73
Ranganadi	Pondage	3 X 135	85
DVC			
Panchet	Storage	2 X 40	80
Tilaiya	Storage	2 X 2	80
Maithon	Storage	3 X 20	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 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) AEC(AUX):

(a) Surface hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.7%

(ii) with static excitation system : 1.00%

(b) Underground hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.9%

(ii) with static excitation system: 1.2%

20.3 Issues discussed in the Consultation Paper

20.3.1 The following issues were highlighted in the Consultation Paper:

"26.6.1 The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. Capacity Index as a measure of plant availability was implemented by the Commission during tariff periods 2001-2004 and 2004-09. It was based on the concept that hydrology risk has to be borne by beneficiaries all the time. After consultation, capacity index concept was modified with the new concept of Normative Annual Plant availability Factor (NAPAF) during 2009-14 and continued during 2014-19 based on actual data. However, in case of a few hydro plants the same was revised. This is based on the premise that hydrology risk is to be shared by the generator & the beneficiary in the ratio of 50:50. There may be need for review of existing values of NAPAF based on actual PAF data for last 5 years.

26.6.2 The norms of auxiliary power consumption of hydro generating station vary from 0.7% to 1.2% based on rotational or static excitation system. The transformation losses are covered as a part of auxiliary consumption."

20.4 Stakeholders' Response

20.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions.

20.4.2 NHPC has stated that NAPAF should be reviewed based on the data available for two Control Periods. Further, as per the existing regulations, the NAPAF of 90% for Pondage Plants and 70% for ROR Plants has been fixed and any increase in NAPAF is not desirable. NAPAF should be fixed such that generating companies are encouraged sufficiently for higher availability for longer period.

a) NHDC has stated that the NAPAF may be appropriately reduced for its ISPS & OSPS as a special case, being a multipurpose project. Anyway, there should be no upward revision in the existing values of NAPAF.

b) NHPC has stated that surface power stations with installed capacity of less than 200 MW with static excitation show average auxiliary consumption higher than the normative (1%) prescribed in the Tariff Regulations. Thus, the Commission may consider normative auxiliary consumption of 1.7% for the surface hydro generating plants having installed capacity of less than 200 MW.

c) NEEPCO has suggested that the Commission may consider the recovery of AFC through Capacity Charges only, as adopted by the Commission during the Control Period 2004 to 2009. NEEPCO is facing backing down instructions of hydro generation from RLDC even during high monsoon, non-spilling period and even during spilling period. This has resulted in generation loss as well as financial loss in the form of less recovery of Energy Charge and improper utilization and wastages of natural resources.

20.5 Commission's Proposal

20.5.1 The Commission, after reviewing the stakeholders' suggestions/comments and based on the actual five years' data for PAF (Annexure I) and AEC (Annexure II) has proposed as follows.

<u>NAPAF</u>

20.5.2 As regards the actual availability achieved by the hydro generating stations, it is observed that most of the generating stations achieved much higher PAF (exceeding 5%) as compared to the current normative annual plant availability factor (NAPAF) norms. Few hydro generating stations, namely Bairasul, Dulhasti, Uri II and Kopli II have marginally exceeded the current NAPAF norms (up to 5%). Further, in case of few other hydro generating stations, namely Dhauliganga, TLDP III, Chutak, Kopli I, Khandong and Doyang, the actual availability has fallen short of the current NAPAF norms. Based on these actual figures, the Commission has proposed the following NAPAF norms for the tariff period 2019-24.

Table 61: Actual and Proposed NAPAF for Hydro Generating Stations

Generating Stations	PAF Actuals					Average	Existing NAPAF Norms	Proposed NAPAF Norms
	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17			
THDC								
THDC Stage I	85.67	84.46	87.31	83.39	81.30	84.43	77.00	80.00
KHEP	74.86	70.32	68.11	70.13	70.89	70.86	67.00	68.00
NHPC								
Bairasul	98.28	93.35	88.06	93.13	93.30	93.22	90.00	91.00
Loktak	92.69	90.86	89.93	89.33	96.91	91.94	85.00	88.00
Salal	65.79	67.61	67.38	70.87	70.44	68.42	60.00	64.00
Tanakpur	64.64	53.91	64.50	67.56	66.20	63.36	55.00	59.00
Chamera-I	97.77	97.39	96.38	96.09	98.02	97.13	90.00	93.00
Uri I	80.75	73.01	79.53	86.21	79.10	79.72	70.00	74.00
Rangit	94.01	92.99	92.29	96.32	97.84	94.69	90.00	92.00
Chamera-II	96.74	97.45	95.45	94.17	98.67	96.49	90.00	93.00
Dhauliganga	93.76	21.06	51.48	84.01	82.58	66.58	90.00	78.00
Dulhasti	85.43	94.08	95.26	95.79	95.26	93.16	90.00	91.00
Teesta-V	86.68	81.61	93.53	92.40	95.09	89.86	85.00	87.00
Sewa-II	81.90	97.18	97.06	97.91	98.13	94.44	85.00	89.00
TLDP III	-	32.54	72.95	88.19	89.51	70.80	85.00	77.00
Chamera III	94.60	88.64	95.34	92.25	80.14	90.19	85.00	87.00
Chutak	29.02	49.90	58.69	39.85	57.35	46.96	50.00	48.00
Nimmo Bazgo	-	67.61	78.10	78.90	81.41	76.50	65.00	70.00
Uri II	-	75.40	59.39	67.16	81.75	70.92	70.00	70.00
Parbati III	-	44.47	33.88	42.18	53.49	43.50	-	43.00
TLDP IV	-	-	-	101.02	92.15	96.59	-	96.00
NHDC								
Indira Sagar	90.15	90.54	88.50	91.24	92.76	90.64	85.00	87.00
Omkareshwar	97.26	98.05	94.35	97.13	95.35	96.43	90.00	93.00
NEEPCO								
Kopili I	62.93	53.13	48.45	56.34	75.28	59.22	79.00	69.00
Khandong	73.88	62.68	52.73	76.34	68.11	66.75	69.00	67.00
Kopili II	84.06	51.08	63.20	80.66	73.75	70.55	69.00	69.00
Doyang	66.40	75.11	63.06	62.18	75.22	68.39	73.00	70.00
Ranganadi	95.14	93.34	86.13	96.34	93.02	92.80	85.00	88.00
NTPC								
Koldam	-	-	-	86.02	97.22	91.62	-	90.00
SJVNL								
Nathpa Jhakri	-	-	-	-	-	-	90.00	90.00
DVC								
Panchet	-	-	-	-	-	-	80.00	80.00
Tilaya	-	-	-	-	-	-	80.00	80.00
Maithon	-	-	-	-	-	-	80.00	80.00

Auxiliary Energy Consumption (AEC)

20.5.3 The Commission has observed that, hydro generating stations with 'Surface – Static Excitation Field', having installed capacity below 200 MW, have significantly higher actual AEC than the existing norm of 1.0%. In case of Bairasul, Loktak, Tanakpur and Nimoo Bagzo hydro generating stations, the actual AEC was much higher than the existing norms. Most of the hydro generating stations with 'Surface – Static Excitation Field', with an exception of Chutak (44 MW) and Dhauliganga (280 MW) have actual AEC lower than the existing norm of 1.20%. Further, the actual AEC of all hydro generating stations of NEEPCO are much lower than the existing norms. Based on these observations, the Commission proposes to adopt the following norms for the Control Period 2019-24.

Table 62: Existing and Proposed AEC Norms for Hydro Generating Stations

Type of Station	Existing AEC Norms (All Capacities)	Proposed AEC Norms	
		Installed Capacity above 200 MW	Installed Capacity upto 200 MW
Surface			
Rotating Excitation	0.7%	0.7%	0.7%
Static	1.0%	1.0%	1.2%
Underground			
Rotating Excitation	0.9%	0.9%	0.9%
Static	1.2%	1.2%	1.3%

20.6 Proposed Provisions

The Commission proposes provisions in Regulations 60 in the Draft Tariff Regulations which is reproduced below.

Norms of Operation for hydro generating stations

"60. Norms of operation for hydro generating stations: (1) The following Normative annual plant availability factor (NAPAF) shall apply to hydro generating station:

(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.

(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 :-

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
THDC			
THDC Stage I	Storage	4x250	80
KHEP	Storage	4x100	68
NHPC			
Bairasul	Pondage	3x60	91
Loktak	Pondage	3x35	88
Salal	ROR	5x115	64
Tanakpur	ROR	3x31.4	59
Chamera-I	Pondage	3x180	93
Uri I	ROR	4x120	74
Rangit	Pondage	3x20	92
Chamera-II	Pondage	3x100	93
Dhauliganga	Pondage	4x70	78
Dulhasti	Pondage	3x130	91
Teesta-V	Pondage	3x170	87

Station	Type of Plant	Plant Capacity No. of Units x MW	NAPAF (%)
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
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 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):

Type of Station	**AEC**	
	Installed Capacity above 200 MW	**Installed Capacity upto 200 MW**
Surface		
Rotating Excitation	0.7%	0.7%
Static	1.0%	1.2%
Underground		
Rotating Excitation	0.9%	0.9%
Static	1.2%	1.3%

"

21 Norms of Operation for Transmission System

21.1 Background

21.1.1 The Commission vide its Order dated 8th December, 2000 had enhanced normative availability for recovery of full transmission charges as well as payment of incentives from 95% specified by the Ministry of Power to 98%. For the Tariff period 2004-09, the Target Availability for recovery of full transmission charges for AC System was fixed at 98%, whereas for HVDC bi-pole links and HVDC back-to-back stations at 95%. The recovery of fixed charges below the level of target availability was on pro rata basis. At zero availability, no transmission charges were payable. For 2009-14, Target Availability for recovery of full transmission charges were fixed for AC System at 98%, HVDC bi-pole links at 92%and HVDC back-to-back Stations at 95%. During the Tariff Period 2014-19, Target Availability for recovery of full transmission charges for AC System as well as HVDC System, were kept same as that of Tariff Regulations, 2009.

21.2 Existing Provisions of the 2014 Tariff Regulations

"38.Normative Annual Transmission System Availability Factor (NATAF) shall be as under:

For recovery of Annual Fixed Charges:

(1) AC system: 98%

(2) HVDC bi-pole links and HVDC back-to-back stations: 95%

For incentive consideration:

(1) AC system: 98.50%

(2) HVDC bi-pole links and HVDC back-to-back Stations: 96%

Provided that for new HVDC stations, NATAF shall be considered as 95% for first three years of operations for the purpose of incentive:

Provided further that no incentive shall be payable for availability beyond 99.75%:

Provided also that for AC system, two trippings per year shall be allowed. After two trippings in a year, additional 12 hours outage shall be considered in addition to the actual outage:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hour shall be multiplied by a factor of 2.

39. Auxiliary Energy Consumption in the sub-station*:*

(a) AC System

The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting and consumption in other equipment shall be borne by the transmission licensee and included in the normative operation and maintenance expenses.

(b) HVDC sub-station

For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS.

The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses."

21.3 Issues discussed in the Consultation Paper

21.3.1 Following issues were brought out in the Consultation paper.

(a) Transmission Availability Factor

- Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors;
- Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system;

- Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and
- Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;

(b) Transmission Losses

- Presently, there is no regulatory framework on specifying the norms for transmission losses. Transmission loss comprises primarily of technical losses, which consists mainly of power dissipation in electricity system components such as transmission line, transformers and measurement systems. The transmission losses are dependent on the best operational practices, efficient planning, level of power flow and avoidance of circular flow. The operational strategies and practices adopted by transmission network operator and system operator impact the transmission losses.
- The transmission losses considered in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply. An option could be to introduce the norms for inter-state transmission losses based on factors within control and international benchmarks.
- The existing approach for operational norms and level of Normative Annual Transmission Availability Factor (NATAF) may be reviewed. The weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and switchable reactor of substation element may also be deliberated upon.

21.4 Stakeholders' Responses

21.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders submitted following comments/suggestions.

a) KERC submitted that the maximum rate of incentive needs to be reduced by increasing the minimum availability requirement from 98.5 to 99 for AC system and 96 to 98 for HVDC system, to reduce the burden on the end consumers.

b) One of the Central Sector stakeholders has submitted that the existing approach for computation of Transmission system availability may be continued for 220 kV and downward voltage level and weightage factors for transformer and reactor may be applied for higher voltage level.. The low voltage system is fault-prone and hence subject to low availability. The transmission losses are dependent on transformer/line loading and ambient condition type of the load. Benchmarking of loss may be limited to 5%.

c) It was further submitted for removal of penalty clause related to generation backing down for HVDC bipole system installed without (n-1) concept, in addition, the normative target annual availability for long HVDC bipoles is required to be reduced to 92% from 95% for certification of transmission system availability and Submission of outage data by Transmission Licensees to RLDC /constituents should be by 5th of the following month. Review of the outage data by RLDC / constituents and forward the same to respective RPC should be by 20th of the following month. Issue of availability certificate by respective RPC should be by 3rd of the next month. Additional 12 hours penalty clause in case of two tripping in a year for AC transmission elements should be removed.

d) In addition, the upper cap of transmission system availability of 99.75% for incentive purpose may be relaxed. It is not advisable to introduce norms for inter-state transmission losses since the factors, which determine transmission losses are not within the control of Transmission Licensees.

e) One of the State Sector stakeholders has submitted that Transmission availability be considered on yearly cumulative basis for Incentive/ Disincentive purpose as addition of buffer zone in incentive criterion can harm the interest in case of smaller transmission system. Transmission loss should not be made a part of NATAF as it is not under the control of the utility and is entirely dependent upon real time loading of the system.

f) One State level stakeholder has supported the introduction of the norms for Inter-state Transmission losses, based on factors within control and international benchmarks.

g) Few beneficiaries have submitted that the availability of transmission system/element is expected to increase with the introduction of new technology like polymer insulators etc. Thus, the mechanism of payment for transmission tariff based on the availability of transmission system should be reviewed.

h) One of the beneficiaries has proposed changes in the incentive mechanism and has suggested considering the percentage availability of each transmission corridor. Further, it has suggested imposition of penalty in case the corridor is not available beyond the set percentage availability target. It has suggested that the incentive percentage linked to the availability should be reviewed and lowered to 0.5%.

i) Some Private Stakeholders have submitted that Incentive formula for HVDC system should not be at par with the AC system.

21.5 Analysis of Actual Performance and Commission's Proposal

21.5.1 PGCIL has submitted region-wise transmission system availability from FY 2012-13 to FY 2016-17 for both AC and HVDC Systems, which is summarised below.

Table 65: Transmission System Availability of AC Transmission System (%)

Region	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average
NR	99.87	99.92	99.72	99.67	99.64	**99.77**
WR	99.91	99.95	99.86	99.85	99.74	**99.86**
ER	99.95	99.88	99.94	99.82	99.91	**99.90**
SR	99.96	99.89	99.83	99.86	99.93	**99.89**
NER	99.88	99.93	99.83	99.94	99.91	**99.90**

Table 66: Transmission System Availability of HVDC Bipole Tx System (%)

Region	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average
Talcher - Kolar	99.32	99.47	99.34	99.36	99.76	**99.45**
HVDC Consolidated*	99.85	99.26	99.25	97.37	97.74	**98.69**
Average						**99.07**

**HVDC Consolidated is a mix data provided by PGCIL consisting of Rihand-Dadri, Balia-Bhiwadi and Sasaram Back to Back HVDC Station.*

Table 67: Transmission System Availability of HVDC Back to Back Stations(%)

Stations	FY 2012-13	FY 2013-14	FY 2014-15	FY 2015-16	FY 2016-17	Average
Gazuwaka	99.73	99.99	97.55	99.75	99.85	**99.38**
Chandrapur	99.79	99.75	99.47	96.93	99.57	**99.10**
Vindhyachal	99.83	98.63	98.93	79.43	80.89	**91.54**
Average						**96.67**

21.5.2 It is observed that, the average transmission system availability for regional AC Transmission System in five regions during FY 2012-13 to FY 2016-17 ranges from 99.76% to 99.93%. In case of HVDC Transmission System and for HVDC bipole scheme, the average transmission system availability ranges from 98.69% to 99.45%, whereas for back-to-back schemes, it ranges from 91.54% to 99.38%.

21.5.3 In case of HVDC sub-stations where the Central Government has allocated an appropriate share from one or more ISGS, the charges for such power are included in operation and maintenance expenses and therefore, the same shall be excluded from Auxiliary Energy Consumption norms.

21.6 Transmission System Availability Factor – Proposed Norms

21.6.1 The Commission proposes provisions in Regulations 61 and Regulation 62 in the Draft Tariff Regulations which is reproduced below.

"61. Normative Annual Transmission System Availability Factor (NATAF): shall be as under**:**

For recovery of Annual Fixed Charges:

(1) AC system: 98.00%

(2) HVDC bi-pole links 95.00% and HVDC back-to-back stations: 95.00%

For incentive consideration:

(1) AC system: 98.50%

(2) HVDC bi-pole links and HVDC back-to-back Stations: 97.50%

Provided further that no incentive shall be payable for availability beyond 99.75%:

Provided also that for AC system, two trippings per year shall be allowed. After two trippings in a year, for every tripping, additional 12 hours outage shall be considered in addition to the actual outage hours:

Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station, outage hours shall be multiplied by a factor of 2.

62. Auxiliary Energy Consumption in the sub-station:

(1) AC System: The charges for auxiliary energy consumption in the AC sub-station for the purpose of air-conditioning, lighting and consumption in other equipment shall be borne by the transmission licensee and included in the normative operation and maintenance expenses.

(2) HVDC sub-station: For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from

one or more ISGS. The charges for such power shall be borne by the transmission licensee from the normative operation and maintenance expenses."

22 Computation of Variable Cost

22.1 Background

22.1.1 The Commission in the 2001 Tariff Regulations did not specify any norms with respect to transit and handling losses of primary fuel. However, the Commission in its subsequent Tariff Regulations approved separate norms for pit head and non-pit head generating stations. The Commission in the 2009 Tariff Regulations, also determined separate norms for landed cost of primary fuel. In the 2014 Tariff Regulations, the Commission maintained the status quo on the transit and handling losses, while stating that in case of imported coal, the transit and handling losses shall be 0.2%.

22.1.2 The Commission in the 2001 Tariff Regulations had defined "the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, gas the case may be" for Gross Calorific Value (GCV) in relation to thermal generation. In the 2014 Tariff Regulations commission specified the gross calorific value for computation of energy charges as per shall be done in accordance with GCV on "as received" basis.

22.2 Existing Provisions of the 2014 Tariff Regulations

30. Computation and Payment of Capacity Charge and Energy Charge for Thermal Generating Stations:

………

(5) 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 charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh.}

(6) 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

ECR = {(GHR – 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 = GHR 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

(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.

GHR =Gross station heat rate, in kCal per kWh.

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/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.

*(7) The generating company shall provide to the beneficiaries of the generating station the 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., as per the forms prescribed at **Annexure-I** to these regulations:*

Provided that the details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal and the weighted average GCV of the fuels as received shall also be provided separately, along with the bills of the respective month:

Provided further that copies of the bills and 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 details should be available on its website on monthly basis for a period of three months.

(8) The landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality of fuel inclusive of royalty, taxes and duties as applicable, transportation cost by rail / road or any other means, and, for the purpose of computation of energy charge, and in case of coal/lignite shall be arrived at after considering normative transit and handling losses as percentage of the quantity of coal or lignite dispatched by the coal or lignite supply company during the month as given below:

Pithead generating stations : 0.2%

*Non-pithead generating stations **:** 0.8%*

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 loss of 0.8% shall be applicable:

Provided further that in case of imported coal, the transit and handling losses shall be 0.2%.

22.3 Issues discussed in the Consultation Paper

24. Fuel - Landed Cost

"24.1 The present regulatory framework provides for the computation of energy charges based on landed cost of fuel. The landed cost of fuel includes the cost components upto the delivery point of the generating stations. Further, as per the present regulations, the energy charges are directly pass through based on the formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. The beneficiaries verify the bills or claims of the energy charge rate while making payment.

24.2 The generating company has to provide the necessary details of the cost included in the landed cost of fuel. Different generating companies follow different practices for supplying such information. Further, asymmetry of information for different fuel sources creates ambiguity for billing energy charges. There may be a need to specify the required information to be supplied and the standard procedure to be followed while claiming bills for energy charges.

24.3 The approach for allowing pass through of the landed cost of fuel was evolved on the premise that the fuel cost is beyond the control of the generating companies as prices were administered. Subsequently, there have been several developments. The Government has opened the coal mine to private companies. Today, the generating company may procure coal either through Coal India Ltd, Open market, e-auction mode, captive mine etc. Further, the Government has also specified the flexible utilization of coal under the existing fuel supply agreement. The generating company has options to optimize the landed cost of fuel based on different procurement and transportation modes, considering the quality, source specific expenses etc.

24.4 The landed cost of fuel constitutes different components such as basic run of mine (ROM) price, sizing charges, surface transportation charges, royalty, stowing excise duty, fuel surcharge, cess etc. Further, the components may vary depending upon the source of coal. In case of railway transport, it involves basic freight, terminal charges, busy season surcharges etc. In case of imported coal, it includes the FOB price, over sea transportation, port handling charges, rail transportation, road transportation etc. As a result, there is wide variations in terms of cost and number of cost components involved in the landed fuel cost, changes in which cause corresponding fluctuations in the tariff. The energy charges largely depend on the fuel cost which is determined by the cost components allowable as part of tariff.

Option for Regulatory Framework:

24.5 (a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified;

(b) The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.

Comments/ Suggestions

24.6 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.

22. Fuel – Gross Calorific Value (GCV)

22.1 Gross Calorific Value (GCV) in relation to thermal generation has been defined in successive tariff regulations issued by the Commission since 2001 as "the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be". GCV is used to compute the Energy Charge payable by the distribution companies/power utilities to the generating companies. The normative energy consumption admissible per unit of electricity generated has been specified by the Commission in the tariff regulations as normative Station Heat Rate (SHR) in terms of kcal/kWh. The ratio of SHR and GCV gives the quantity of coal used per unit of electricity generated.

Therefore, GCV being used for the computation of energy input becomes extremely important as any increase/reduction in GCV decreases/increases the admissible coal consumption affecting the cost of power.

22.2 Energy Charge constituting about 60-70% of the total cost of generation tariff has major impact on cost to end consumers. In order to balance the interest of both the generating companies as well as the distribution companies (and ultimately the end consumers), the measurement of GCV of coal used needs to be as accurate as the true representative of the coal consumption is required.

22.3 GCV of coal is measured at different points and accordingly, various GCV terminologies are used namely “GCV As Billed”, "GCV As Received" and "GCV As Fired". “GCV As Billed”, also called as “Invoice GCV” is indicated by the suppliers in the dispatch invoice and payment for the coal is made to the suppliers on the basis of “GCV As Billed”. However, “GCV As Billed” is based on GCV measured in a controlled environment. "GCV As Received" is GCV measured at the generating station upon receipt of coal in the station. "GCV As Fired" is computed before feeding coal into coal bunkers of the generating unit for power generation.

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. "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.

22.5 In the entire value chain from mine end to generating station end, the loss of GCV can take place on account of grade slippage at mine end, during transportation (transit with railway) and during storage (at generating stations). The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive lower energy than what was billed by the coal companies. These are beyond the control of the generating companies.

22.6 Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations.

22.7 In case of imported coal, sampling and proximate analysis are being done at Free on Board (FOB) and at Cost Insurance Freight (CIF). The coal is transported by rail from port to the generating stations. Since the existing regulatory framework provides that the GCV is to be measured as on received basis at generating end, the same is followed for imported coal too. In case of imported coal, the GCV measurement is followed on Air Dryed basis at CIF for billing purpose, whereas in case of domestic coal, the same is measured at the mine end.

Option for Regulatory Framework

22.8 (a) Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify losses to be booked to Coal supplier or Railways.

(b) Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations.

(c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.

Comments/ Suggestions

22.9 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any."

22.4 Stakeholders' Response

22.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted following comments/suggestions.

a) KERC submitted that the GCV as per Fuel Supply Agreement (FSA) needs to be ensured. The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period. Stipulate procedure for sourcing fuel from alternate source including ceiling rate.

b) Few Central Generating Stations submitted that generating companies do not have control over grade / GCV of Coal received at the station. GCV measurement should be on "As Fired Basis" in place of "As received Basis". Allocated Coal Blocks are difficult to operate, which were considered not suitable for production by CIL. So Landed cost of coal produced/ mined from these coal blocks may be higher than the notified price of CIL for same Grade. Therefore, the landed cost at actual should be consider for passing on to the consumer.

c) Many State level stakeholders commented that loss in GCV during transport of Coal may be beyond the control of the Generating Companies, but it is the responsibility of the Generator to enter into appropriate contract with the Coal Supplier and Transporter beneficiary has no role to play in ensuring the Quality and Quantity of Coal..

d) Few State level stakeholders have submitted that in order to meet the shortfall in availability of fuel from the primary source, generators are using costlier imported coal / coal from alternate source for blending. It has been suggested to incorporate suitable Regulation so that generator declares separate availability on domestic as well as imported coal / coal from alternate source in line with the availability declaration by gas based generating stations. This will enable the beneficiary to schedule power based on their Merit Order.

e) Many beneficiaries have submitted that DISCOMs pay the Gencos based on the invoices raised by CIL which contains the GCV "as billed" and quantity of the coal. The GCV used for computation of energy charges should be based on "as billed" basis.

f) Few beneficiaries have submitted that normative blending ratio may be specified for existing and new plants separately in consultation with the beneficiaries. Further, the generator should declare blending ratio to the beneficiaries in advance. Normative upper ceiling for blending may be specified.

g) Few beneficiaries have submitted that drop in GCV between 'as received at coal mines end' and 'as received at power station end' 'as fired'. should be quantified on percentage basis and generator should be directed to reduce the GCV loss in phased manner. It should be a parameter of performance of generating companies. Curtailment of ROE for Generator should be linked with their performance similar in line with non-achievement of normative distribution loss in case of DISCOM.

h) Most of the private stakeholders have submitted that the generating companies have been forced to resort to blending largely because of insufficient supply of domestic coal. Therefore, in case the beneficiary(ies) do not provide their consent for allowing the blending, then the generator should be considered deemed available or the target availability may be reduced corresponding to fuel shortage, and the resulting lower availability on account of lower availability of fuel should be ignored. Alternatively, there should not be any requirement for taking consent from beneficiary to the extent of imported coal replacing shortage of domestic coal. A process for procurement of such coal may be defined, and all costs allowed as pass through once the process is followed.

22.5 Commission's Proposal

22.5.1 The Commission after going through the suggestions and actual data is of the view that the current norms are largely close to the actuals, apart from few exceptions and therefore the Commission proposes to retain the current norm for transit and handling losses for pit head generating stations. However, the Commission has observed that in case of non-pit head generating stations, which are located more than 1,000 km away from the mines, the actual transit and handling losses are significantly higher. Therefore, the Commission proposes a higher transit and handling losses norms of 1.20% for non-pit head generating stations with distance from coal mine exceeding 1,000 km. Further, the Commission proposes that in case of imported Coal, the transit and handling losses applicable for pit head generating stations, i.e. 0.20% shall continue to apply, similar to that applicable in Tariff Regulations, 2014.

22.5.2 The Commission has noted the Central Electricity Authority has recommended for allowing a margin for loss of GCV between "GCV As received" basis at generation station (wagon top) to "GCV As Fired" basis. The recommended GCV loss figures in case of pit head generating stations is 85-100 Kcal/kg and in case of non-pit head generating stations of 105-120 kcal/kg. However, the Commission has proposed a weighted average GCV loss of 85 Kcal/Kg on account of variation during storage at generating station for calculation of energy charge, without differentiating between pit head and non-pit head generating stations.

22.5.3 Some of the stakeholders have suggested to consider the measurement of GCV on 'as billed basis'. The Commission has introduced the measurement of GCV on as received basis with effect from 1.4.2014. Thereafter, third party sampling has been adopted by the generating companies at the loading end of mine and unloading end of the generating station. This provision has brought transparency in measurement of GCV . The system of measurement of GCV on 'as received basis' is required to be implemented in all coal based thermal generating stations effectively. The Commission proposes to continue with the measurement of GCV on as received basis.

22.5.4 After reviewing stakeholders comments and suggestions, the Commission proposes that on account of shortage of fuel or optimization of operation, for blending, use of alternative source of fuel supply shall be permitted to the generating station. However, this will be subject to the condition that in case the energy charge rate exceeds either 30% of the base energy charge rate as approved by the Commission for that year or 20% of the energy charge rate for the previous month, whichever is lower, the generating station shall undertake prior consultation with the beneficiary.

22.5.5 Considering the fact that the thermal generating stations shall be required to set up pollution control facilities to meet the revised emission norms, the

Commission has proposed norms for reagent such as limestone, Sodium Bi-Carbonate, Urea and Anhydrous Ammonia, which shall be consumed during the operation of emission control system (pollution control facilities). The Commission has suggested the norms for consumption of ammonia and urea based on following working:

Ammonia calculation for SCR

Reaction in SCR

$$4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$$

$$6NO_2 + 8NH_3 \longrightarrow 7N_2 + 12H_2O$$

Table 63: Consumption Norm working for Ammonia

Particulars	Unit	Figure
Flue gas generation per MW assumed	Nm^3 / hr	4,000
NOx Emission	Mg / Nm^3	600
NOx as per Norm	Mg / Nm^3	100
NOx reduction required	Mg / Nm^3	500
NOx in gm / hr	g / hr	2,000
No. of Moles of NOx to be removed	g-moles / hr	43.48
No. of Moles of Ammonia required	g-moles / hr	59.71
NH_3 required	g / hr	1,015.1
NH_3 required	Kg / hr	1.02

Reaction in SNCR for Urea:

$$4NO + 2CO(NH_2)_2 + O_2 \longrightarrow 4N_2 + 4H_2O + 2CO_2$$

Table 64: Consumption Norm working for Urea

Particulars	Unit	Figure
Urea Mol. Weight		60
Flue gas generation per MW assumed	Nm^3 / hr	4,000
NOx Emission	Mg / Nm^3	500
NOx as per Norm	Mg / Nm^3	300
NOx reduction required	Mg / Nm^3	200
NOx in gm / hr	g / hr	800
No. of Moles of NOx to be removed	g-moles / hr	26.667
No. of Moles of Ammonia required	g-moles / hr	26.667
Urea required	g / hr	1,600
Urea required	Kg / hr	1.6

22.5.6 Based on the above analysis, the Commission after providing some margin on the consumption of ammonia and urea has proposed the following norms.

Table 65: Proposed Reagent Consumption Norms

Particulars		Specific Reagent Consumption (gms / kWh)
Standard Particulate Matter		-
NOX Control System	Combustion Modification	-
	Selective Non-Catalytic Reduction	1.85 (Urea)
	Selective Catalytic Reduction (SCR)	1.60 (Anhydrous Ammonia)

22.5.7 NSR depend upon many items.

i) Wet Type :

Reagent Used "Lime stone/ lime / $CaCO_3$"

Chemical Reaction (1):

S(coal) + O_2(air) = SO_2(in flue gas)

Molecular Weight

32 + 2X16=32 = 64

32 moles of sulphur produces 64 moles of sulphur dioxide on combustion in boiler

Chemical reaction (2):

$CaCO_3$ + H_2O = $CaSO_4.H_2O$ + CO_2

Molecular Weight
40+12+3*16=100 + 64 + 18 = -

64 moles of sulphur dioxide is removed by 100 moles of lime

From chemical reaction no. 1, 1 T of Sulphur produces 2 T of SO_2, assuming 0.5 % of sulphur in Indian Coal, therefore 1 Ton of coal would contain 0.5 kg of sulphur. If 500 MW unit coal fired is in the range of 380 T/hr, accordingly sulphur burned in boiler = 0.5% *380 = 1.9 T/hr, it would produce SO_2 : 1.96 * 2 = 3.8 T/hr

From Chemical reaction no. 2, 100 moles of lime is required to absorb 64 moles of SO_2, i.e. for 1 T SO_2 about 1.56 T (=100/64) of lime is required for absorption.

From the above para, SO_2 produced = 3.8 T/hr and Lime (CaCO3) required = 1.56 * 3.8 = 5.93 T/hr

22.6 Proposed Provisions

22.6.1 In the second Proviso of Regulation 48 of the Draft Tariff Regulations, the norms of Transit & Handling loss of imported coal has been inadvertently linked with non pit head station instead of pit head station. This error shall be addressed suitably at the time of finalisation of Tariff Regulations.

22.6.2 The Commission proposes Regulation 46 to 50 in the Draft Tariff Regulations which is reproduced as below:-

'46.Variable Cost: The variable cost in respect of the thermal generating Stations shall comprises landed fuel cost of primary fuel, Cost of secondary fuel oil consumption and cost of reagents on account of implementation of the revised emission control standards.

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 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.

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 :-

Thermal Generating station	Distance of Generating Station from source of fuel	Transit and Handling Loss (%)
Pit head	-	0.20%
Non-pit head	Upto 1000 KM	0.80%
	Above 1,000 KM	1.20%

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.

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 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.

50.Landed Price of Reagent (Limestone, Sodium Bi-Carbonate, Urea and Anhydrous Ammonia etc.): (1) Where the specific reagent such as limestone, Sodium Bi- Carbonate, Urea and Anhydrous Ammonia are used during operation of emission control system, the landed price of such reagents shall be determined based on normative consumption specified in clause (2) of this Regulation and purchase price of the reagent through competitive bidding, applicable statutory charges and transportation cost;
(2) The normative consumption of specific reagent for the various technologies installed for Emission Control System shall be considered as under:

<table>
<tr><th colspan="2">Particulars</th><th>Specific Reagent Consumption (gms / kWh)</th></tr>
<tr><td rowspan="2">SOX Control System</td><td>Wet Limestone Type</td><td>15.00 (Limestone)</td></tr>
<tr><td>Dry sorbent injection</td><td>12.00 (Sodium Bi-Carbonate)</td></tr>
<tr><td>Standard Particulate Matter</td><td>-</td><td></td></tr>
<tr><td rowspan="3">NOX Control System</td><td>Combustion Modification</td><td>-</td></tr>
<tr><td>Selective Non-Catalytic Reduction</td><td>1.85 (Urea)</td></tr>
<tr><td>Selective Catalytic Reduction (SCR)</td><td>1.60 (Anhydrous Ammonia)</td></tr>
</table>

Provided that the specific reagent consumption specified as above is allowed on provisional basis, and shall be applicable only where emission control system is installed. The above norms shall be reviewed based on the actual of performance during the 2021-22."

23 Peak - Off Peak Tariff

23.1 Background

23.1.1 Central Electricity Authority (CEA) in the National Electricity Plan (NEP) 2018 for Generation, has projected energy and peak demand by 2026-27 as 299 GW. The Indian Electricity network is built to deal with the highest possible peak demand.. CEA in its load generation balancing report (LGBR) has observed the peak power deficit as 2.1 per cent during 2017-18At present there is no mechanism to ensure that generators declare higher availability during high load period. There is a need to encourage declaration of higher available generation capacity during peak season/duration, when Discom need it. Thus, there is need to incentivise generators to plan and make available its generation capacity and supply power during peak/off-peak period as per requirement of load. The pricing framework should encourage generators to plan and adjust its generation resources to cater to diurnal variation/seasonal variation in demand of its beneficiary and also should facilitate power system operations to achieve load-generation balance in most optimal and efficient manner. Hence, the Commission has proposed to introduce the Capacity Charge in two parts (i) Capacity Charge for Peak period and (ii) Capacity Charge for Off-Peak period.

23.2 Existing Provisions of the 2014 Tariff Regulations

"30. Computation and Payment of Capacity Charge and Energy 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 / allocation in the capacity of the generating station.*

(2) *The capacity charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:*

$CC_1 =$ $(AFC/12)(PAF_1 / NAPAF)$ *subject to ceiling of* $(AFC/12)$

$CC_2 =$ $((AFC/6)(PAF_2 / NAPAF)$ *subject to ceiling of* $(AFC/6)) – CC_1$

$CC_3 =$	$((AFC/4)\ (PAF_3 / NAPAF)$ *subject to ceiling of* $(AFC/4)) - (CC_1+CC_2)$
$CC_4 =$	$((AFC/3)\ (PAF_4 / NAPAF)$ *subject to ceiling of* $(AFC/3)) - (CC_1+CC_2+CC_3)$
$CC_5 =$	$((AFC \times 5/12)\ (PAF_5 / NAPAF)$ *subject to ceiling of* $(AFC \times 5/12)) - (CC_1+CC_2+CC_3+CC_4)$
$CC_6 =$	$((AFC/2)(PAF_6 / NAPAF)$ *subject to ceiling of* $(AFC/2)) - (CC_1+CC_2+CC_3+CC_4+CC_5)$
$CC_7 =$	$((AFC \times 7/12)\ (PAF_7 / NAPAF)$ *subject to ceiling of* $(AFC \times 7/12)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6)$
$CC_8 =$	$((AFC \times 2/3)\ (PAF_8 / NAPAF)$ *subject to ceiling of* $(AFC \times 2/3)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6+CC_7)$
$CC_9 =$	$((AFC \times 3/4)\ (PAF_9 / NAPAF)$ *subject to ceiling of* $(AFC \times 3/4)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6+CC_7+CC_8)$
$CC_{10} =$	$((AFC \times 5/6)\ (PAF_{10} / NAPAF)$ *subject to ceiling of* $(AFC \times 5/6)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6+CC_7+CC_8+CC_9)$
$CC_{11} =$	$((AFC \times 11/12)\ (PAF_{11} / NAPAF)$ *subject to ceiling of* $(AFC \times 11/12)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6+CC_7+CC_8+CC_9+CC_{10})$
$CC_{12} =$	$((AFC)\ (PAF_Y / NAPAF)$ *subject to ceiling of* $(AFC)) - (CC_1+CC_2+CC_3+CC_4+CC_5+CC_6+CC_7+CC_8+CC_9+CC_{10}+CC_{11})$

Provided that in case of generating station or unit thereof or transmission system or an element thereof, as the case may be, under shutdown due to Renovation and Modernisation, the generating company or the transmission licensee shall be allowed to recover part of AFC which shall include O&M expenses and interest on loan only.

Where,

AFC	*Annual fixed cost specified for the year, in Rupees.*
NAPAF =	*Normative annual plant availability factor in percentage.*
$PAF_N =$	*Percent Plant availability factor achieved upto the end of the nth month.*

PAFY = Percent Plant availability factor achieved during the Year

CC_1, CC_2, CC_3, CC_4, CC_5, CC_6, CC_7, CC_8, CC_9, CC_{10}, CC_{11} and CC_{12} are the Capacity

Charges of 1^{st}, 2^{nd}, 3^{rd}, 4^{th}, 5^{th}, 6^{th}, 7^{th}, 8^{th}, 9^{th}, 10^{th}, 11^{th} and 12^{th} months respectively.

(3) *The PAFM upto the end of a particular month and PAFY shall be computed in accordance with the following formula:*

$$PAFM \text{ or } PAFY = 10000 \times \sum_{i=1}^{N} DC_i / \{ N \times IC \times (100 - AUX) \} \%$$

Where,

AUX=Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the i^{th} 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.

Note: DC_i 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.

(4) *Incentive to a generating station or unit thereof shall be payable at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) as specified in regulation 36 (B).*

23.3 Issues discussed in the Consultation Paper

. As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required to resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand.

23.4 Stakeholders' Response

23.4.1 In response to the issues brought out in the Consultation Paper, the stakeholders' submitted their following comments/suggestions.

a) Many Central level stakeholders have submitted that the present practice of recovery of fixed charge based on annual PAF should continue.

b) Some Central level stakeholders have submitted that Determination of PAF on peak and off peak would distort the purported intent.

c) One State level stakeholder has suggested separate Normative Availability for Peak period and Off Peak period and that both should be achieved separately. Regional Power Committee should notify the period at the beginning of the financial year in consultation with beneficiaries.

d) Few beneficiaries have submitted that the norms should be linked with peak period and peak season when generator can be allowed to realize full Per Unit (PU) fixed cost of proposed three-part tariff based on declared PAF. For other period & other season, such PU realization will be less, say 70-75% of Per Unit FC. This philosophy will regulate fixed charge per unit throughout the year with minimum deviation.

e) Few Beneficiaries have submitted that it has been observed that there is trend of supplying lesser energy during the peak season/duration and then compensating this by higher generation when Discom may not need it. Provision of minimum plant availability of 85% is often flouted by generator.

f) One Beneficiary has submitted that peak and off-peak availability may be specified as 90% for 4 months peak period and 82.5% for 8 months off-peak period.

g) Few Beneficiaries have submitted that the payment of fixed charges should be done based on some weighted average of demand availability during peak and off peak period. In the event plant is not able to declare availability during peak hours, its availability during off peak hours should also be changed accordingly.

23.5 Commission's Proposal

23.5.1 The 2014 Tariff Regulations provide for two part tariff for a thermal generation station, viz. Fixed Cost (Annual Fixed Charge i.e. AFC) and Energy Charge (EC), while linking the recovery of fixed charges with the availability of generating station. The availability of 85% is specified as the norm and the present regulatory framework allows recovery of annual fixed charges based on cumulative availability during the year. Accordingly, a generating station can fully recover its fixed cost, if it achieves the normative level of availability of 85% over the year. This allows the generating station with the flexibility to make up for the lower availability for a part of the year, by achieving increased availability during the remaining part of the year, in order to achieve cumulative normative availability mark for the year.

23.5.2 In this context, many of the distribution utilities have submitted that, while the generating stations are allowed to completely recover their fixed cost, the present Regulations do not address the issue of declaration of lower availability during the peak demand period and declare higher availability during off-peak period. This often forces the Discoms to procure power from short term market during peak demand period. However, during low demand period, the generating stations often declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. As a result of which, the beneficiaries do not get the electricity when required the most. .

23.5.3 To address the above concern and also to bring in the element of "Value in Electricity Pricing", the Commission considered the above observations and proposes the following mechanism for recovery of Annual Fixed Charge during Peak and Off-Peak periods.

23.5.4 It is proposed to allow recovery of fixed cost of generation in two parts, separately for Peak Period and Off-Peak Period for a day. Total Peak period during a day shall not be less than 4 hours and the remaining hours will be Off-Peak Period. Concerned RLDCs will specify the peak and off-peak periods, on monthly basis in advance for the respective regions. Normative Availability Factor of the Plant, duly factoring in planned and forced outages as specified in the Regulations, will remain the same for each day (for Peak and Off-Peak periods), and will serve as reference/basis for the purpose of recovery of fixed cost.

23.5.5 It is proposed to allow recovery of Fixed Cost at differential rates during Peak and Off-Peak Periods, while keeping the capacity charge rate for Peak Period 25% more than that of Off-Peak Period. At normative PAF, considering the above differential rate of recovery, the AFC recovery ratio (weightage factor) between the Peak and Off-Peak periods shall vary depending upon the number of Peak and Off-Peak hours.

23.5.6 To address the concerns of fuel availability, if any, it is further proposed that, computation of AFC recovery to be based on cumulative performance during a month. In order to recover 100% recovery of monthly Peak Period AFC, the Generating Station has to achieve Normative Peak PAF during the Peak periods of the month (i.e. cumulative peak hours for a month) and for 100% recovery of monthly Off-Peak Period AFC, the Generating Station has to achieve Normative Off-Peak PAF during the Off-Peak period of the month (i.e. cumulative off-peak hours for a month).

23.5.7 In order to encourage the generators to optimally utilize the fuel during peak hours it is proposed 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 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. However, 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;

23.5.8 The AFC recovery mechanism proposes to allow under-recovery of Capacity Charge in "Peak" or "Off-Peak" periods in a month to carry forward for recovery of Capacity Charge in their respective "Peak" or "Off-Peak" periods till the end of the quarter. However, carry forward of under-recovery of Capacity Charge shall not be allowed for recovery from one quarter to the subsequent quarter.

23.5.9 To further promote availability and generation during the peak hours, it is proposed that in addition to the capacity charge, any generation beyond the generation corresponding to the specified NQPAF plus 2% during a month shall carry differential incentive rates, i.e. Rs. 0.65/kWh for generation during Peak Period and Rs. 0.50/kWh for generation during Off-Peak Period. In other words, there shall be a dead band of 2% over and above the NQPAF for the purpose of incentive.

23.5.10 The formula for calculation of "Capacity Charge Rate" is provided below.

Capacity Charge Rate:

CCRp = (WFP x AFC) / (IC x NPAFp x NDM x NHDp)

Where,

NPAFp = Normative Plant Availability Factor for Peak Hours of the Day

NHDp = Normative Number of Peak Hours in a Day

CCRop = (WFoP x AFC) / (IC x NPAFop x NDM x NHDop)

Where,

NPAFop = Normative Plant Availability Factor for Off-Peak Hours of the Day

NHDop = Normative Number of Off-Peak Hours in a Day

23.5.11 Illustrations:

Table 66: Peak / Off-Peak Illustration Assumptions

Particulars	Unit	Existing Tariff Regulations, 2014 Normative	Draft Tariff Regulations, 2019		
			Peak	Off-Peak	Overall
Assumptions					
Capacity	MW	210	210	210	210
CC required to be recovered during the year	Rs. Cr.	148.66			148.66
CC required to be recovered during the month		12.2186			12.2186
Normative PAF	%	83%	83%	83%	83%
Normative Running Hours	No.	24	4	20	24
Number of Days in the Month	No.	30	30	30	30
Number of Units Generated	MU	125.50	20.92	104.58	125.50
Price of Peak (Addl.) over Off-Peak Tariff	%		25%		

Table 67: Scenario 1

PAF of both Peak and Off-Peak Segments equal to Normative PAF

Details	Peak	Off-Peak	Overall
Actual Number of Running Hours	4	20	24
Normative PAF	0.8300	0.8300	0.8300
Achieved PAF	0.8300	0.8300	0.8300
Number of Units Generated	20.916	104.58	125.496
Weightage Factor	0.20	0.80	1.00
Capacity Charge Rate (Rs.) (per MW/hr) (peak 25% over Off-Peak)	1168.35	934.68	973.62
Capacity Charge per day (Rs. Cr.)	0.0815	0.3258	0.4073
Capacity Charge per month (calculated) (Rs. Cr.)	2.4437	9.7749	12.2186
Allowable Capacity Charge per month (Rs. Cr.)	2.4437	9.7749	12.2186
Difference over Normative	0.0000	0.0000	
Finally Payable Capacity Charge (Rs. Cr.)	2.4437	9.7749	12.2186
Incentive due to higher energy generation	0.0000	0.0000	0.0000
Total Payable to Genco (Rs. Cr.)			**12.2186**

- The allowable recovery of Capacity Charge for the month is Rs. 12.2186 Cr. (Rs. 2.4437 Cr. for Peak Period and Rs. 9.7749 Cr. for Off-Peak Period)
- By achieving 83% PAF during Peak Period, complete recovery of Peak CC Rs. 2.4437 Cr. is made.
- By achieving 83% PAF during Off-Peak Period, complete recovery of Off-Peak CC Rs. 9.7749 Cr. is made.

Table 68: Scenario 2

PAF of Peak Segment exceeds Normative PAF and that of Off-Peak Segment falls Short of Normative PAF

Details	Peak	Off-Peak	Overall
Actual Number of Running Hours	4	20	24
Normative PAF	0.8300	0.8300	0.8300
Achieved PAF	0.8800	0.8200	0.8300
Number of Units Generated	22.176	103.32	125.496
Weightage Factor	0.20	0.80	1.00
Capacity Charge Rate (Rs.) (per MW/hr) (peak 25% over Off-Peak)	1168.35	934.68	973.62
Capacity Charge per day (Rs. Cr.)	0.0864	0.3219	0.4073
Capacity Charge per month (calculated) (Rs. Cr.)	2.5909	9.6571	12.2480
Allowable Capacity Charge per month (Rs. Cr.)	2.4437	9.7749	12.2186
Difference over Normative	0.1472	-0.1178	
Finally Payable Capacity Charge (Rs. Cr.)	2.4437	9.7749	12.2186
Incentive due to higher energy generation	0.0491	0.0000	0.0491
Total Payable to Genco (Rs. Cr.)			**12.2677**

- The allowable recovery of Capacity Charge for the month is Rs. 12.2186 Cr. (Rs. 2.4437 Cr. for Peak Period and Rs. 9.7749Cr. for Off-Peak Period)
- By achieving 88% PAF (more than NQPAF) during Peak Period, complete recovery of Peak CC Rs. 2.5909 Cr. is made.
- By achieving 82% PAF (less than NQPAF) during Off-Peak Period, complete recovery of Off-Peak CC is not made.
- Difference over normative recovery for peak and off peak is Rs 0.1472 Cr and – (less) Rs 0.1178 Cr, but the difference is offset by higher recovery during peak period.
- Further, a gain of Rs. 0.0491 Cr. is made owing to excess generation at rate of Rs. 0.65 p.u. (in Peak), beyond the dead-band of 2%.

Table 69: Scenario 3

PAF of Peak Segment falls short of Normative PAF and that of Off-Peak Segment exceeds Normative PAF

Details	Peak	Off-Peak	Overall
Actual Number of Running Hours	4	20	24
Normative PAF	0.8300	0.8300	0.8300
Achieved PAF	0.7500	0.8600	0.8417
Number of Units Generated	18.9	108.36	127.26
Weightage Factor	0.20	0.80	1.00
Capacity Charge Rate (Rs.) (per MW/hr) (peak 25% over Off-Peak)	1168.35	934.68	973.62
Capacity Charge per day (Rs. Cr.)	0.0736	0.3376	0.4130

Details	Peak	Off-Peak	Overall
Capacity Charge per month (calculated) (Rs. Cr.)	2.2082	10.1282	12.3364
Allowable Capacity Charge per month (Rs. Cr.)	2.4437	9.7749	12.2186
Difference over Normative	-0.2355	0.3533	
Finally Payable Capacity Charge (Rs. Cr.)	2.2082	9.7749	11.9831
Incentive due to higher energy generation	0.0000	0.0630	0.0630
Total Payable to Genco (Rs. Cr.)			**12.0461**

- The allowable recovery of Capacity Charge for the month is Rs. 12.2186 Cr. (Rs. 2.4437 Cr. for Peak Period and Rs. 9.7749 Cr. for Off-Peak Period)
- By achieving 75% PAF (less than NQPAF) during Peak Period, complete recovery of Peak CC is not made, resulting in a loss of Rs. 0.2355 Cr.
- By achieving 86% PAF (more than NQPAF) during Off-Peak Period, complete recovery of Off-Peak CC is made (Rs. 9.7749 Cr.).
- However, over-achievement in Off-Peak Period, does not allow full recovery of Peak CC by setting aside the loss in Peak Period CC.
- Further, a gain of Rs. 0.063 Cr. is made owing to excess generation at rate of Rs. 0.50 p.u. (in Off-Peak), beyond the dead-band of 2%.

Table 70: Scenario 4

PAF of both Peak and Off-Peak Segments exceed Normative PAF

Details	Peak	Off-Peak	Overall
Actual Number of Running Hours	4	20	24
Normative PAF	0.8300	0.8300	0.8300
Achieved PAF	0.8800	0.8700	0.8717
Number of Units Generated	22.176	109.62	131.796
Weightage Factor	0.20	0.80	1.00
Capacity Charge Rate (Rs.) (per MW/hr) (peak 25% over Off-Peak)	1168.35	934.68	973.62
Capacity Charge per day (Rs. Cr.)	0.0864	0.3415	0.4277
Capacity Charge per month (calculated) (Rs. Cr.)	2.5909	10.2460	12.8369
Allowable Capacity Charge per month (Rs. Cr.)	2.4437	9.7749	12.2186
Difference over Normative	0.1472	0.4711	
Finally Payable Capacity Charge (Rs. Cr.)	2.4437	9.7749	12.2186
Incentive due to higher energy generation	0.0491	0.1260	0.1751
Total Payable to Genco (Rs. Cr.)			**12.3937**

- The allowable recovery of Capacity Charge for the month is Rs. 12.2186 Cr. (Rs. 2.4437 Cr. for Peak Period and Rs. 9.7749 Cr. for Off-Peak Period)
- By achieving 88% PAF (more than NQPAF) during Peak Period, complete recovery of Peak CC is made (Rs. 2.4437 Cr.).
- By achieving 87% PAF (more than NQPAF) during Off-Peak Period, complete recovery of Off-Peak CC is made (Rs. 9.7749 Cr.).

Further, a gain of Rs. 0.1751 Cr. is made owing to excess generation at rate of Rs. 0.65 p.u. (in Peak) and Rs. 0.50 p.u. (in Off-Peak), beyond the dead-band of 2%.

Table 71: Scenario 5

PAF of both Peak and Off-Peak Segments fall short of Normative PAF

Details	Peak	Off-Peak	Overall
s	4	20	24
Normative PAF	0.8300	0.8300	0.8300
Achieved PAF	0.8100	0.8200	0.8183
Number of Units Generated	20.412	103.32	123.732
Weightage Factor	0.20	0.80	1.00
Capacity Charge Rate (Rs.) (per MW/hr) (peak 25% over Off-Peak)	1168.35	934.68	973.62
Capacity Charge per day (Rs. Cr.)	0.0795	0.3219	0.4016
Capacity Charge per month (calculated) (Rs. Cr.)	2.3848	9.6571	12.0419
Allowable Capacity Charge per month (Rs. Cr.)	2.4437	9.7749	12.2186
Difference over Normative	-0.0589	-0.1178	
Finally Payable Capacity Charge (Rs. Cr.)	2.3848	9.6571	12.0419
Incentive due to higher energy generation	0.0000	0.0000	0.0000
Total Payable to Genco (Rs. Cr.)			**12.0419**

- The allowable recovery of Capacity Charge for the month is Rs. 12.2186 Cr. (Rs. 2.4437 Cr. for Peak Period and Rs. 9.7749 Cr. for Off-Peak Period)
- By achieving 81.00% PAF (less than NQPAF) during Peak Period, complete recovery of Peak CC is not made, resulting in a loss of Rs. 0.0589 Cr.
- By achieving 82% PAF (less than NQPAF) during Off-Peak Period, complete recovery of Off-Peak CC is not made, resulting in a loss of Rs. 0.1178 Cr.

23.6 Proposed Provisions

23.6.1 In view of above, the Commission proposes Regulation 51 in the Draft Tariff Regulations which is reproduced below.

"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 (per MW/hr) shall be 25% more than that of applicable for Off-Peak hours. The 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,

$$CC_{pd} = \frac{(AFC)}{(NDY)} x \text{ WFp};$$

$$CC_{opd} = \frac{(AFC)}{(NDY)} x \text{ WFop};$$

and,

$$\text{WFp} = \frac{(1.25 \; x \; NHDp \; x \; PAFDp)}{[(1.25 \; x \; NPAFp \; x \; NHDp) + (NPAFop \; x \; NHDop)]};$$

$$\text{WFop} = \frac{(NHDop \; x \; PAFDop)}{[(1.25 \; x \; NPAFp \; x \; NHDp) + (NPAFop \; x \; NHDop)]}$$

Subject to,

$$\text{CCm} \leq \frac{(AFC \; x \; NDM)}{NDY} \text{ ; and}$$

$$\sum_{i=1}^{NDM} CCpdi \leq \frac{(AFC \; x \; NDM)}{(NDY)} x \frac{(1.25 \; x \; NPAFp \; x \; NHDp)}{[(1.25 \; x \; NPAFp \; x \; NHDp) + (NPAFop \; x \; NHDop)]} \text{; and}$$

$$\sum_{i=1}^{NDM} CCopdi \leq \frac{(AFC \; x \; NDM)}{(NDY)} x \frac{(NPAFop \; x \; NHDop)}{[(1.25 \; x \; NPAFp \; x \; NHDp) + (NPAFop \; x \; NHDop)]}$$

Where,

CCm = Capacity Charge for the month

NDM = Number of Days in the month

CCpd = Capacity Charge for the peak hours of the day

CC_{opd} = Capacity Charge for the off-peak hours of the day

AFC = Annual Fixed Cost

NDY = Number of Days in the year

NHD_p = Normative Number of Peak Hours in a Day

NHD_{op} = Normative Number of Off-Peak Hours in a Day

$PAFD_p$ = Plant Availability Factor achieved during the Peak Hours of the Day

$PAFD_{op}$= Plant Availability Factor achieved during the Off-Peak Hours of the Day

$NPAF_p$ = Normative Plant Availability Factor for Peak Hours of the Day

$NPAF_{op}$= 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 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 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. Further, the total recovery of Capacity Charges for the month shall not exceed proportionate Capacity Charge for the month linked to number of days in the month;

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. Further, the total recovery of Capacity Charges for the month shall not exceed proportionate Capacity Charge for the month linked to number of days in the month;

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:

$$\text{PAFD or PAFM or PAFQ} = 10000 \times \sum_{i=1}^{N} DC_i \,/\, \{ N \times IC \times (100 - AUX) \} \,\%$$

Where,

AUX = Normative auxiliary energy consumption in percentage.

DCi = Average declared capacity (in ex-bus MW), for the i^{th} 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: DC_i 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 excess of ex-bus energy corresponding to Normative Quarterly Plant Load Factor (NQPLF) as specified in Regulation 59 (B) of these regulations."

24 Combined Petitions for Transmission Elements

24.1 Background

24.1.1 The transmission system involves a large number of individual transmission elements which are commissioned at different point of time. Sometimes, commissioning of individual elements takes more time due to ROW issues, forest clearance, etc. Therefore, the number of tariff petitions in transmission projects becomes large, depending upon commissioning of different elements. The finalization of tariff for an individual element involves the same judicial processes as for the whole project.

24.2 Existing Provisions of the 2014 Tariff Regulations

7. Application for determination of tariff:

……..

(2) The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with the Procedure Regulations, in respect of the transmission system or elements thereof anticipated to be commissioned within 180 days from the date of filing of the petition.

24.3 Issues discussed in the Consultation Paper

24.3.1 Following issues have been brought out in Consultation Paper:-

"The determination of capital cost of transmission system is distinguished on two counts – existing assets i.e. those commissioned prior to commencement of relevant tariff period and new assets commissioned during tariff period. Presently, the capital cost of the existing assets is determined on projected basis at the beginning of the tariff period and trued up on completion of the tariff period i.e. twice during tariff period. One alternative to simplify the process is to determine the tariff of existing assets based on actual capital expenditure instead of projected capital expenditure, so that two applications of existing assets can be reduced to one in each tariff period.

Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets.

41.3 Further in case of new assets of transmission system, single petition may be admitted for all the individual elements of the project which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis and apportioned on proportion to the capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project."

24.4 Stakeholders' Response

24.4.1 In response to the issues brought out in the Consultation Paper by the Commission, the stakeholders submitted following comments/suggestions.:

a) KERC has supported Commission's Proposal.

b) One Central Level Generator has submitted that single petition may be admitted for all the individual elements which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis based on capital cost of individual elements combined with the Capital base of Existing System

c) One Central Transmission Licensee submitted that they should be allowed to bill provisional tariff from date of the commissioning of the asset without approaching CERC for the same. CERC may define norms for provisional tariff to be billed for each type of asset based on time over-run and cost over-run. Licensee shall approach CERC with the tariff petition for final order after the commissioning of the asset which shall include all the details such as the scheme approval in Standing Committee Meeting and RPC, Investment approval by Company's board, all the requisite certificates i.e. CEA/RLDC/CMD certificate, DOCO letter, along with the Auditor Certificate and complete tariff forms. To reduce the number of petitions, it shall file the petition for final order for an asset or group of assets if the capital cost of the asset (or group of assets) is above a threshold amount (say, Rs 100 Cr.) or if there are no further assets in the project anticipated to be commissioned in that financial year.

d) Some beneficiaries have accepted the proposal for reducing number of petitions as the proposed move will ensure that the tariff is approved on commissioning of the assets.

e) Some other organizations have supported that admission of single petition for the individual elements of new transmission assets commissioned within a year.

24.5 Commission's Proposal

24.5.1 Every tariff period, the Commission processes a large number of tariff determination petitions for transmission systems, as the existing Tariff Regulations provide for determination of tariff even for an element of a transmission system. Often, on anticipated COD basis of a transmission element, petition for determination of tariff is submitted. Often such tariff petition undergo amendments due to shifting of anticipated COD. The Commission with an objective to reduce the number of tariff determination petitions in transmission has proposed clubbing of petitions. The Commission has proposed minimum capital cost of Rs. 500 Crore for the individual transmission tariff petitions. However, to accommodate schemes of smaller size, the Commission has also proposed 80% of the cost envisaged in the Investment Approval or Rs. 500 Crore, whichever is lower.

24.6 Proposed Provisions

24.6.1 In view of above, the Commission proposes provision in Regulation 9 in the Draft Tariff Regulations which is reproduced below:-

9. Application for determination of tariff:

(1) …...

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on capitalization of not less than 80% of the cost envisaged in the Investment Approval or Rs. 500 Crore, whichever is lower, as on the anticipated date of commercial operation;

25 Application for Tariff Determination

25.1 Background

25.1.1 The generating company or the transmission licensee, as the case may be, may make an application for determination of tariff in accordance with Central Electricity Regulatory Commission (Procedure for making of application for determination of tariff, publication of the application and other related matters) Regulations, 2004, as amended from time to time or any statutory re-enactment thereof, in respect of the units of the generating station or the transmission lines or sub-stations of the transmission system, completed or projected to be completed within six months from the date of application. In case of new projects, the Utilities are allowed to submit the tariff applications based on projected expenditure for the Project which are likely to complete within 6 months from the date of application.

25.2 Existing Provisions of the 2014 Tariff Regulations

7. Application for determination of tariff:

(1) The generating company may make an application for determination of tariff for new generating station or unit thereof in accordance with the Procedure Regulations, in respect of the generating station or generating units thereof within 180 days of the anticipated date of commercial operation.

(2) The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with the Procedure Regulations, in respect of the transmission system or elements thereof anticipated to be commissioned within 180 days from the date of filing of the petition.

25.3 Issues discussed in the Consultation Paper

25.3.1 This matter was not raised in the Consultation Paper.

25.4 Stakeholders' Response

25.4.1 Stakeholders have not submitted any suggestions on this issue.

25.5 Commission's Proposal

25.5.1 The existing Tariff Regulations provides for filing of petition for determination of tariff upto 180 days before the anticipated date of commercial operation of a generating station or transmission system. The main objective of this provision is to determine a tariff for the project by the time it is commissioned. However, the Commission has observed that after provisional tariff has been determined, the commissioning of the assets have been delayed beyond the anticipated date of commercial operation. This not only results in iterative tariff determination process, but also substantial variance between the interim tariff so determined, and the tariff determined based on the final capital cost.

25.5.2 The Commission recognises that it is imperative for the generating company or the transmission licensee and also for the beneficiary, to have tariff determined as on the date of commercial operation, to initiate the billing procedure. At the same time, the Commission also desires to ensure that the interim tariff to be as close to the final tariff as possible. Therefore, the Commission proposes to reduce the time between the date of filing of tariff petition and anticipated date of commercial operation from 180 days to 60 days, allowing the .submission of Management Certificate for indicating the capital cost due to shorter timeline, subject to submission of Auditor Certificate subsequently.

25.6 Proposed Provisions

25.6.1 In view of above, the Commission proposes Regulation 9 in the Draft Tariff Regulations which is reproduced below:-

"9. Application for determination of tariff:

(1) The generating company or the transmission licensee may make an application for determination of tariff for new generating station or unit thereof or the transmission system or element thereof in accordance with the Procedure Regulations within 60 days of the anticipated date of commercial operation:

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on capitalization of not less than 80% of the cost envisaged in the Investment Approval or Rs. 500 Crore, whichever is lower., as on the anticipated date of commercial operation;

Provided further that the generating company or the transmission licensee, as the case may be, shall submit Auditor Certificate and in case of non-availability of Auditor Certificate, a certificate duly signed by an authorised person, not below the level of Director of the company, indicating the capital cost incurred as on the date of commercial operation and the projected additional capital expenditure for respective years of the tariff period 2019-24;

Provided also that where interim tariff of the generating station or unit thereof and the transmission system or element thereof including communication system has been determined based on Management Certificate, the generating company or the transmission company shall submit the Auditor certificate not later than 60 days from date of granting interim tariff."

26 Non-Tariff Income and Income from Other Business

26.1 Background

26.1.1 Non-tariff Income for generating company or transmission licensee means income relating to the regulated Business other than from Tariff and shall constitute income from activities like sale of fly ash, disposal of old plants and machineries, sale of scrap, rental income, interest on advances to suppliers, interest income, etc. which are incidental to the regulated business. Non-Tariff Income shall exclude income from Other Business as mentioned below.

26.1.2 Income from Other Business means income from Other Businesses from optimum utilisation of its assets and shall be considered in respect of a transmission licensees only, in accordance with the provisions of section 41 of the Act.

26.1.3 There is no regulatory framework specified in the existing 2014 Tariff Regulations for sharing of Non-Tariff Income. Regarding, Other Income or Income from Other Business. While there is no specific provision in the existing Tariff Regulations, 2014, it is governed by the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007.

26.2 Existing Provisions of the 2014 Tariff Regulations

26.2.1 There is no provision in existing 2014 Tariff Regulations , either for sharing of Non-Tariff Income or for Income from Other Business.

26.3 Issues discussed in the Consultation Paper

Following issues have been brought out in Consultation Paper:-

"31.1 The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.

31.2 Presently, the revenue from telecom business is adjusted at the rate of Rs. 3000/- per KM, which was fixed in 2007. It may need review."

26.4 Stakeholders' Response

26.4.1 In response to the issues brought out in the Consultation Paper by the Commission, the stakeholders submitted following comments/suggestions.

a) Most of the Central Level Stakeholders have expressed reservation to the proposal of reducing O&M expenditure on account of non-tariff income. A separate fund has to be created with the sale proceeds of fly ash and to be earmarked for utilization of specific purpose till 100% utilization of fly ash is achieved. Thus, sale of Fly ash cannot be treated as non-tariff income for adjustment with O&M.
b) One Transmission Utility has submitted that as per direction of CERC, Rs.3000/km is being adjusted from their revenue from telecom business and is being credited to the beneficiaries. This takes care of the treatment of income from other business and hence no separate adjustment is required.
c) Few state level stakeholders have submitted that regarding ash disposal most plants are unable to sell fly ash and on the contrary, have to provide transportation subsidy (Rs.150/T) as per government guidelines. Such cost should be allowed in additional O&M. Also the existing norms should be revised upward
d) Few beneficiaries have submitted that Gencos should be allowed to retain only 1/3rd of their other business net income from activities like consultancy; fly ash disposal etc. (after deducting expenses towards income from other business from gross income from other business) and 2/3rd should be passed to the Beneficiaries in proportion of their allocation.

e) Few beneficiaries have submitted that the revenue earned from telecom business should be reviewed as the telecom sector has under gone rapid changes.. Profits earned from telecom business should be shared with Discoms in ratio of 2/3:1/3, where 1/3rd should be allowed to be retained by Transmission Companies and 2/3rd should be passed on the Licensees. This will be in line with Section 41 of the Electricity Act, 2003

f) Most of the private sector stakeholders have not supported the proposal and have submitted that disposal of fly ash is new event and generators are required to incur the additional expenditure for utilization of ash which is not covered under O&M Expense at present. As per the MoC Notification, Generator is required to maintain separate account for any revenue earned and need to utilize the same as provided therein. Therefore, it cannot be considered as non-tariff income.

g) They have also submitted that Non-Tariff incomes are miniscule in nature for generating. Further, the generator has to expand efforts and manpower for earning any such incomes.

h) Some private sector organization have submitted that O&M Norms for generating companies are fixed taking into account actual expenditure for past period. While doing so, revenue on account of disposal of old assets, interests of advances, revenue for telecom business etc. are already taken into account.

i) Some private sector organization have submitted that Non-Tariff income from the core business should be treated as such to reduce the tariff. Revenue from telecom business should be shared on 50:50 basis, subject to a minimum of Rs. 20,000/km.

26.5 Commission's Proposal

26.5.1 The Commission after going through the comments and suggestion is of the view that the under Cost-plus regime each and every cost incurred in generation or transmission of power is paid by the beneficiaries or the long term customers, as the case may be. Therefore, any non-tariff income generated by generating company or the transmission licensee from regulated business should be equitably shared with such beneficiaries or long term customers. Therefore, the Commission proposes that non-tariff income in case of generating station and transmission system shall be shared in the ratio of 50:50.

26.5.2 While determining O&M expenses norms for generating stations and transmission system, the Commission excludes rebates and incentives given by the generating company and transmission licensee to its beneficiaries or long term customers, as the case may be. Further, late payment surcharge or interest on late payment surcharge because of its penal nature shall not form part of Non-Tariff Income.

26.5.3 Regarding sharing of Other Income, the same is governed by Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007 amended from time to time.

26.6 Proposed Provisions

26.6.1 In view of above, the Commission proposes Regulation 72 in the Draft Tariff Regulations which is reproduced below.

"**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;

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.

……..

74. Sharing of income from other business of transmission licensee: The income from other business of transmission licensee shall be shared with the long term customer in the manner as specified in the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007 and subsequent amendment thereof."

27 Mismatch of Commissioning of Transmission System

27.1 Background

27.1.1 The Commission has observed several instances of mismatch between the commissioning of the transmission system and the downstream or upstream systems. The commissioning of the transmission system has commercial significance as the revenue flow starts from date of commercial operation. However, due to mismatch in the commissioning of transmission system with upstream system (generating station or other inter-state transmission system) or downstream system (other inter-state transmission system or intra-state transmission system), the transmission licensee is not be able to put its completed assets into transmission service. The transmission licensee, therefore, is unable to recover the transmission charges. The Commission has received a number of petitions seeking adjudication in the matters of determination of the date of commercial operation or the transmission system, recovery of transmission charges in case of delay in establishing upstream or downstream assets.

27.2 Existing Provisions of the 2014 Tariff Regulations

27.2.1 The 2014 Tariff Regulations provides the framework for execution of Implementation Agreement between the transmission licensee and the generating station and between the transmission licensee. Sub-clause (34) of Regulation 3 of the 2014 Tariff Regulations defined Implementation Agreement as under:

*"(34) "**Implementation Agreement**" means the agreement, contract or memorandum of understanding, or any such covenant, entered into (i) between transmission licensee and generating station or (ii) between transmission licensee and developer of the associated transmission system for the execution of project in coordinated manner;*

4. Date of Commercial Operation

...

(3) Date of commercial operation in relation to a transmission system shall mean the date declared by the transmission licensee from 0000 hour of which an element of the transmission system is in regular service after successful trial operation for

transmitting electricity and communication signal from sending end to receiving end:

Provided that:

(i) where the transmission line or substation is dedicated for evacuation of power from a particular generating station, the generating company and transmission licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement in accordance with Regulation 12(2) of these Regulations:

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

27.2.2 The above said Implementation Agreement (IA) is expected to address the obligations of the parties involved in the development of the transmission system and corresponding liability for failure to discharge such obligations. The Implementation Agreement is expected to address coordination, sharing of debt service obligations in case of delay in commercial operation, rescheduling of schedule commercial operation date in case of adverse progress and sharing of the transmission charges in case of deemed COD.

27.3 Issues discussed in the Consultation Paper

27.3.1 The issue of mismatch of the transmission system leading to delay in commercial operation date has been summarised in the consultation paper.

"35.4 Delay can occur in the commercial operation due to factors beyond control or non-commissioning of associated transmission system. In case of the transmission system, the delay on account of non-commissioning of downstream or upstream system is more relevant. Since the declaration of commercial operation date attracts the liability of fixed charges or the transmission charges, as the case may be, the parties dispute the commercial operation date. In order to stream line the process of the declaring commercial operation date in case of the delay and to make aware the parties upfront about the consequences of delay, provisions could be made for demarcation of responsibilities or for Indemnification Agreement.”

27.3.2 The comments or suggestions of the stakeholders were invited on: (i) the issue of acceptance of COD of transmission line if the generating project or upstream or downstream transmission assets are not commissioned; (ii) Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long Term Access Agreement respectively; and (iii) Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations;

27.4 Stakeholders Response

27.4.1 The comments and suggestions were invited on the issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned.

a) Some of the transmission licensee submitted that while planning a transmission system, a new substation is planned mostly on request of States to enable them to draw their share from ISGS as well as to meet the load growth. Sometimes, substation is planned to anchor a long AC line. Further, the implementation of substations is taken up after consent by States in respective SCMs/ RPCs. It is the responsibility of states to draw power from ISTS, through implementation of 220 kV downstream lines. Implementation of downstream network is commenced 1 or 2 years after ISTS projects due to less gestation period.

b) It is further submitted by the transmission licensees that in case States are not able to implement the downstream network matching with ISTS, transmission licensee should not be penalised for that. If CoD of transmission licensee is shifted to match with the downstream network, the project IRR gets reduced considerably. During the mismatch period, transmission licensee is deprived of return on equity, O&M charges, depreciation even though it has to incur expenditure on Debt servicing and O&M of the Asset. Thus, entire risk is transferred to Transmission licensee despite timely completion of its scope.

c) In order to avoid any dispute between generating company & transmission licensee, a joint tripartite certification of COD between generating company transmission licensee & Central Electricity Authority may be made mandatory.

d) Existing provisions provide for recovery of transmission charges from the generator in case when the evacuation system is ready and generator is not ready. Similarly, it is suggested that when generator is ready and evacuation system is not ready then liability of Annual Fixed charges, IDC and IEDC shall be on the transmission licensee.

e) The liability for payment of transmission charges should be fixed on generators or beneficiaries in case of mismatch with generation. In case the same is payable by beneficiaries, the same may be recovered by the beneficiaries from the generators as per the terms and conditions of PPA.

f) All entities i.e. generators, STU / CTU and beneficiaries must work together in a coordinated manner to achieve COD and all the entities must be invited at the trial runs and must give consent for the same.

g) COD of a transmission line should not be considered if any of the upstream or downstream element is not ready, since the very purpose of the power evacuation cannot be met.

h) For thermal generation station, the commercial operation date should be linked with the end beneficiaries tie up, as well as the commissioning of the evacuation system requirement. Similarly, for transmission assets, the COD should be linked with the commissioning of the generating project, end beneficiary tie-up and upstream or downstream connectivity.

i) Commercial Operation date of transmission system exclusively associated together with the generating station or unit should be linked so as to enable completion of both in a well-coordinated and timely manner.

27.5 Commission's Proposal

27.5.1 The issue of mismatch of the transmission system with upstream and downstream system has been examined by the Commission. The Commission has observed that even after introducing the provisions of the Implementation Agreement in the 2014 Tariff Regulations, the issue of mismatch of the transmission system still continued.

27.5.2 The Commission examined various options to ensure matching of milestones and arrived at a considered view that, the issue of mismatch should be addressed through explicit financial liability arrangement .. Accordingly, separate provision is proposed to be added to address the mismatch of the commissioning of the transmission system.

27.6 Proposed Provisions

27.6.1 In view of above, the Commission proposes Regulation 46 to 50 in the Draft Tariff Regulations which is reproduced below.

"6. Treatment of mismatch in date of commercial operation: (1) In case of mismatch of the date of commercial operation of the generating station and the transmission system, the treatment of the transmission charges shall be determined as under:

(a) Where the generating station has not achieved the commercial operation as on the date of commercial operation of the associated transmission system (which is not before the SCOD of the generating station) and the Commission has approved the date of commercial operation of such transmission system in terms of Regulation 5(2) of these regulations, the generating company shall be liable to pay the transmission charges of the associated transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the generating station or unit thereof achieves commercial operation;

(b) Where the associated transmission system has not achieved the commercial operation as on the date of commercial operation of the concerned generating station or unit thereof, the transmission licensee shall make alternate arrangement for the evacuation from the generating station at its own cost, failing which, the transmission licensee shall be liable to pay the transmission charges to the generating company at the rate of the applicable transmission charges of the region as determined in accordance with the Sharing Regulations till the transmission system achieves the commercial operation.

Provided that despite making alternative arrangement of evacuation, if the associated transmission system does not achieve the date of commercial operation within the six months of date of commercial operation of the generating station, the transmission licensee shall be liable to pay to the generating company the applicable transmission charges of the region as determined in accordance with the Sharing Regulations in addition to the above.

(2) In case of mismatch of the date of commercial operation of the transmission system and the transmission system of other transmission licensee, the treatment of the transmission charges shall be determined as under:

(a) Where an interconnected transmission system of other transmission licensee has not achieved the commercial operation as on the date of commercial operation of the transmission system (which is not before the SCOD of the interconnected transmission system) and the Commission has approved the date of commercial operation of such transmission system in terms of Regulation 5(2) of these regulations, the other transmission licensee shall be liable to pay the transmission charges of the transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the interconnected transmission system achieves commercial operation;

(b) Where the transmission system has not achieved the commercial operation as on the date of commercial operation of the interconnected transmission system of other transmission licensee, the transmission licensee shall be liable to pay the transmission charges of such interconnected transmission system to the other transmission licensee and in the absence of transmission charges, at the applicable transmission charges of the region as determined in accordance with the Sharing Regulations till the transmission system achieves the commercial operation."

28 Integrated Coal or Lignite Mine

28.1 Background

28.1.1 Government of India, on 21st October, 2014, has notified "The Coal Mines (Special Provisions) Ordinance, 2014 [now "The Coal Mines (Special Provisions) Act, 2015 (11 of 2015) or "The Coal Mine Act"] which provides for the coal allocation through public auction or through allotment order. As per Section 5 of the Coal Mine Act, the allocation of mine through allotment order is allowed to a Government Company and to Case-2 generation projects.

28.1.2 The coal mines have been allotted to various Government Companies and entities such as NTPC Ltd. and Damodar Valley Corporation (DVC) for specified end use of power generation. Pakri-Barwadih coal mine was allotted to NTPC Ltd. prior to promulgation of the Coal Mine Act, while the remaining coal blocks namely, Chatti-Bariatu & Chatti-Bariatu (south), Kerandari, Dulanaga, Talaipalli, Benai, Bhalumuda and Mandakini-B have been allotted to NTPC Ltd. after promulgation of the Coal Mine Act, by the Government of India through Government dispensation route. Besides, Kudanali-Luburi coal block has been allotted to joint venture company of NTPC Ltd. and J&KSPDCL, Banharadih coal block allotted to Jharkhand Government, has been assigned to a joint venture company of NTPC Ltd. and Government of Jharkhand for Patratu TPP. All of these mines have been allotted by the Government of India through Allotment Order followed by Coal Block Development and Production Agreement (CMPDA).

28.1.3 Unlike allocation by auction, the allocation by Allotment Order on the basis of Government dispensation, is without specifying any cost of coal mine or price of coal. The allotment documents and standard Coal Mine Development and Production Agreement (CMPDA) issued by the Ministry of Coal, GoI do not provide any coal price for using coal in specified end use plant, except specifying the end use as power generation.

28.1.4 The Pakri-Barwadih coal mine allotted to NTPC Ltd. commenced production at partial capacity from 7.12.2016, while the remaining portion of the coal mine shall be developed subsequently by NTPC Ltd. in stages. The coal sourced from Pakri-Barwadih coal mine is already being used at

Vindhyachal-V and Barh-B generating stations for the purpose of supplying power to distribution licensees. The tariff of Vindhyachal-V and Barh-B generating station is determined by the Commission under Section 79(1) read with Section 62 of the Electricity Act, 2003. While determining the tariff, the Commission is required to consider the coal price used for generation and supply of power to distribution licensees.

28.1.5 The Ministry of Power vide letter dated 16.4.2015, under Section 107 of the Act, has issued a direction to the Commission, to review and determine the energy charges for supply of electricity by generating company to a distribution licensee under already concluded power purchase agreement (PPA) and where the coal is being sourced from coal mine auctioned or allotted under Coal Mines (Special Provision) Act, 2015 and rules framed thereunder. The relevant provision is extracted as under:

"3.1 The Central Electricity Regulatory Commission, shall review and determine the energy charges for cost plus Power Purchase Agreements under Section 62 or that in tariff bid based Power Purchase Agreements under Section 63, as the case may be, and shall review the components of fuel price or energy charges including:

a. Run of Mine(ROM) price of coal as per auction or allotment of coal mine;

b. Transporation cost along with distance to the end use power plant (Rail, road and other modes separately),

c. Washery Charges, if any;

d. Crushing Charges;

e. Royalty, Duties and leviest etc.;

f. Other charges"

28.1.6 In accordance with the above direction of the Ministry of Power, the Run of Mine (ROM) price of coal is to be reviewed by the Commission.

28.1.7 The Commission has been entrusted with the jurisdiction of the tariff under Sections 61, 79 read with 178 of the Act. The word "tariff" includes the capacity charges and the energy charges for generation. Under Section 79 under Part X of the Act, the Commission has been vested with the power to regulate the tariff of generating companies. The tariff in respect of the generating stations includes the components of fixed cost and energy cost. Since fuel cost is the single large component of energy cost the input price of coal from the integrated mine sourced by the generating station shall be required to be determined by the Commission.

28.2 Issues discussed in the Consultation Paper

28.2.1 The issue of determination of cost of coal from integrated mine had been discussed in the Consultation Paper. The relevant extract is mentioned below:-

"D. Integrated Power Project with Coal Mine

5.4.1 Coal Mines have been allocated to the NTPC Ltd. and Damodar Valley Corporation (DVC). The present regulatory framework allows pass through of the fuel (coal) cost as determined by the Coal India Ltd. However, in case of coal supplied from the integrated mine or mine owned by the generating company, the challenge will be the determination of the coal cost."

28.3 Commission's Proposal

28.3.1 The coal from mine allotted to the generating company through allotment method will be used for the generating station whose tariff is being determined by this Commission under the Tariff Regulations. For this purpose input price of coal sourced from such mine allocated to, needs to be determined Accordingly, the Commission proposes a framework for determination of input price of coal sourced from integrated mine.

28.3.2 Following non-financial factor have been considered while proposing the framework.

a) In case of captive mine, the entire coal production will be supplied to specific generating station, whereas in case of basket mine, the generating company shall indicate the allocation of coal to each identified generating stations.;

b) Approved Mining Plan under clause (b) of sub-section (2) of section 5 of the Mines & Minerals (D&R) Act, 1957 is recognized in the Tariff Regulations as acceptable document for development, timeline and schedule of commencement of coal supply;

c) Both departmental mode of coal mine development, and development through Mine Development Operator (MDO) mode are recognized.

d) Capital expenditure and additional capital expenditure for various key components, including cost of land (government, private and cultivating including R&R), plant & machinery (CHP, Railway sliding, crushing, PS, etc.) and plant & machinery (HEMM, loading and unloading, control, etc.) with reference to commercial operation date and date of achieving target capacity are considered for determination of input price. ;

e) De-capitalization of HEMM, exclusion of filled land, relinquishment of land, if any are removed from capital cost.

28.3.3 Following financial factors have been considered while proposing the framework.

a) O&M expenses will include employee expenses, administrative & general expenses, repairs and maintenance expenses, expenses on drilling, explosives, transportation (within mine) and crushing. However, these expenses shall be commensurate with volume of extraction.

b) Mine closure expenses are allowed as per the annual Mine Closure Cost calculated based on the guideline issued in this regard by Ministry of Environment and Forest, GoI.

c) For equipment/machinery, depreciation will be charged as per the applicable provisions of the Companies Act, 2013 or as notified by Ministry of Corporate Affairs (MCA), GoI from time.

d) Statutory payments viz., Upfront Payment, Reserve price, Clean Environment Cess, Royalty, Stowing Excise Duty, GST for MDO, Contribution towards district Mineral Foundation & National Mineral Exploration Trust under 'The Mines and Minerals (Development and Regulation) Amendment Act, 2015, Electricity consumption tax or any other tax as notified by the Central/State Government are charged based on actuals.

e) Debt-Equity Ratio and Return on Equity, will be as in the case of generating assets and/or transmission system.

28.4 Proposed Provisions

28.4.1 After considering all relevant aspects, the Commission proposes Regulations 36 to 45 for determination of input price of coal from integrated mine allotted to the generating company, whose tariff is determined by the Commission as under.

<u>COMPUTATION OF CAPITAL COST OF INTEGRATED MINE AND INPUT PRICE</u>

36. Input Price for variable charges: (1) Where the generating company has the arrangement for supply of coal or lignite from the integrated mine(s) allocated to one or more of its generating stations as end use project, the variable charge component of tariff of the generating station shall be determined based on the input price of coal or lignite, as the case may be, from such integrated mines in accordance with these regulations. For this purpose, the generating company shall maintain the account of such integrated mine separately.

(2) These regulations shall apply in all cases where mine is allocated to the end use generating station whose tariff is to be determined by the Commission.

(3) The input price of lignite from the integrated mine shall be determined by the Commission for which appropriate regulations shall be notified separately. Till such time, the Commission shall continue to adopt the guidelines specified by the Ministry of Coal, Government of India.

(4) These regulations shall apply to the mines achieving commercial operation on or after 1.4.2019 and also the mines which have been declared under commercial operation during 2018-19 and whose input price has not been determined by the Commission.

37. Date of Commercial Operation: (1) The date of commercial operation in case of an integrated mine shall mean the date declared by the generating company on occurrence of earliest of the following milestones unless otherwise stated in the project report:

a) Beginning of the financial year immediately after the year in which the 25% of rated capacity as per mining plan; or

b) Beginning of the financial year immediately after the year in which the value of production is more than total expenditure; or

c) Two years of touching of coal or lignite;

(2) The input price for supply of coal from of the integrated mines prior to date of commercial operation shall be considered at the notified price of Coal India Limited for the corresponding grade of coal supplied to the power sector.

(3) Any value of coal realized by the generating company from supply of coal prior to date of commercial operation shall be adjusted against the capital cost of the integrated mine.

38. Application for determination of Input Price: (1) The generating company shall file a petition before the Commission as per **Annexure- I (Part IV)** for determination of the input price for the variable cost along with the tariff petitions for one or more generating stations in accordance with the provisions of these regulations.

(2) The generating company shall submit the details of capital expenditure and additional capital expenditure incurred and projected to be incurred duly certified by the Auditor, wherever applicable.

39. Capital Cost: (1) The Capital cost for development, operation and closure of the integrated mine, shall be determined by the Commission after taking into account the approved mining plan, detailed project report, capital expenditure incurred, additional capital expenditure projected to be incurred, mine closure plan, cost audit report.

(2) The expenditure incurred for development of the integrated mine by the generating company upto date of commercial operation shall be considered for the purpose of capital cost and the expenditure incurred after the date of commercial operation till the date of achieving target capacity shall be treated as capital work in progress (CWIP) and shall be capitalized on year to year basis as additional capital expenditure corresponding to the coal production level specified in the progressive mining plan or actual production, whichever is higher;

(3) If the generating company has appointed any agency for development and operation of integrated mine, the assets belonging to the agency appointed by the generating company shall not form part of capital cost.

(4) The capital expenditure incurred shall be admitted after prudence check.

(5) The Commission may get the capital expenditure and additional capital expenditure, if any, of the integrated mine as furnished by the generating company vetted by the Central Mine Planning and Design Institute Ltd (CMPDIL) or any other independent agency.

39. Additional Capitalisation after commercial operation upto date of target capacity: (1) The capital expenditure in respect of the integrated coal mine of generating station incurred or projected to be incurred, after the date of commercial operation and upto the date of achieving target capacity may be admitted by the Commission, subject to prudence check.

(2) Capital expenditure incurred after the date of commencement of production upto the date of achieving target capacity shall be recognized as capital work in progress and admitted as additional capital expenditure during the respective years of the tariff period corresponding to the production targets envisaged in the as per progressive mining plan;

40. Additional Capitalisation after date of target capacity: The capital expenditure, in respect of the integrated coal mine of generating station incurred or projected to be incurred, within the scope of production plan, after the date of achieving target capacity, may be admitted by the Commission, subject to prudence check.

41. Debt: Equity Ratio: Debt-Equity Ratio of 70:30 to be considered as on date of Commercial Operation for a particular coal mine. Actual equity in excess of 30% of the capital cost shall be treated as normative loan and in case actually equity deployed is less than 30% the actual equity shall be considered. The Debt: Equity ratio shall be applied to the capital cost of each year arrived after considering the Written Down Value of assets as per the industry practice followed in coal sector which may be as per Income Tax Act, 1961 or as per the Companies Act, 2013.

42A. Depreciation: Depreciation in respect of integrated coal mine shall be computed from the date of commercial operation and value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. 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.

42B. Operation and Maintenance Expenses: The Operation and Maintenance expenses of mine shall be determined based on the original project cost for first year and thereafter, it shall be escalated at the average rate of wholesale price index (WPI) for each financial year.

42C. Interest on Working Capital: (1) The working capital of the integrated mine shall cover:

(i) Input cost of coal towards stock, if applicable, for 15 days of coal production corresponding to the normative production level as per the approved mining plan;

(ii) Consumption of stores and spare including explosives, lubricants and fuel @ 15% of operation and maintenance expenses;

(iii) Operation and maintenance expenses for one month;

(2) 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 mine is declared under commercial operation:

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;

(3) Interest on working capital shall be payable on normative basis notwithstanding that the generating company has not taken loan for working capital from any outside agency.

43. Return on Equity: Return on equity shall be computed at the base rate of 15.50%. The base rate of return on equity shall be grossed up with the effective tax rate of the respective financial year.

44. Interest on Loan: The rate of interest shall be the weighted average rate of interest calculated on the basis of actual loan portfolio.

45. Determination of input price: (1) The input price of coal sourced from the integrated mine shall be derived based on the production cost and shall comprise following components:

(a) Capital Cost;

(b) Depreciation;

(c) Interest on loan capital;

(d) Return on equity;

(e) Interest on working capital; and

(f) Operation and maintenance expenses

(2) The input price of coal of such generating company whose integrated mine has been brought under commercial operation shall be determined by the Commission, after taking into account the information provide as per **Appendix V;**

(3) The Commission shall approve the input price per Metric Tonne (MT) after the prudence check and considering the information provided by the generating company as specified in clause (2) of this Regulation.

(4) At the start of the tariff period, in respect of such generating station having integrated mine, the Commission through specific tariff orders shall approve the input price of per metric tonne as calculated above. The input price per Metric Tonne so approved for the first month of supply of from the integrated mine, shall form the basis for arriving at input price for subsequent months and periods. In case of non-availability of information before raising the bill, the generating company may raise provisional bill, which can be subsequently adjusted against the final bill.

Provided that the generating company shall provide details of input price as per prescribed formats as per **Annexure-I** to the beneficiaries.

(5) The input price per Metric Tonne (MT) at the start of supply from integrated mine shall be trued up by the generating company at the end of every financial year on the basis of actual cost taking into account the audited financial statements and cost audit report / cost accounting records as well as any directions of the Commission, if any, in this regard and shall refund or recover the amount from the beneficiaries at the Bank Rate."

29 Miscellaneous Issues

29.1 Fresh Consent

29.1.1 Clause 5.1 of the erstwhile Tariff Policy, 2006 provided for competitive procurement of power by Discoms as under:

"All future requirement of power should be procured competitively by distribution licensees except in certain cases of expansion of existing projects or or where there is a State controlled/owned company as an identified developer and where regulators will need to resort to tariff determination based on norms provided that expansion of generating capacity by private developers for this purpose would be restricted to one time addition of not more than 50% of the existing capacity.

Even for the Public Sector projects, tariff of all new generation and transmission projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition."

29.1.2 Ministry of Power vide its letter dated 9th December 2010 provided certain exemptions to certain generation projects from the tariff based competitive bidding route, which included projects for which PPA(s) have been signed on or before 5.1.2011. This resulted in a number of PPA being signed between generating companies and distribution licensees before 5.1.2011. Accordingly, all generation projects for which PPA(s) have been signed before 5.1.2011, the tariff is required to be determined by the Appropriate Commission under provisions of section 62 of the Act.

29.1.3 However, even after almost eight years, there are many generating projects where there is hardly any progress. The Commission is of the view that there is a need to reassess the interest of the related parties in the proposed generation project. Accordingly, the Commission has proposed for obtaining fresh consent of the beneficiaries in case the project has not achieved financial closure as on 31.03.2019. The proposed provision in the Draft Tariff Regulations are reproduced below:

"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."

29.2 Cut-off Date

29.2.1 In order to give sufficient time to complete the balance works after the date of commercial operation of a project and to close the contracts, the Commission during Control Period 2004-09 decided a minimum period of around one year to be provided for completing the balance work. As such, Commission decided the cut-off date to be the first financial year closing after the date of commercial operation of the generating station. However, it was found that stations achieving COD in the last quarter would be getting only about 12 to 15 months for completion of balance works and payments of liabilities after the COD. Therefore, during control period 2009-14, definition of 'Cut-Off Date' was amended in such a way that projects commissioning upto third quarter of a financial year would get additional two years after close of financial year in which the project was commissioned, while the project commissioning in the last quarter of a financial year would get additional three years after close of financial year in which the project was commissioned.

29.2.2 In order to provide an uniform period to all the projects, the Commission has proposed to allow a period of thirty six calendar months (three years) to all projects from the last day of the month in which the project is commissioned.

29.2.3 It is noticed that in draft notification, it has been mentioned as three year instead of thirty six months which shall be dealt with suitably at the time of finalisation of Regulations. Accordingly, the definition of 'Cut off date' is proposed to be amended as under:

"3. Definitions. - In these regulations, unless the context otherwise requires:-

…..

(14) 'Cut-off Date' means the last day of the calendar month after three years from the date of commercial operation of the project;"

29.3 In-principle Approval in specific circumstances

29.3.1 The 2014 Tariff Regulations allows the generating company or the transmission licensee, to undertake additional capital expenditure in various circumstances including that is outside original scope and after cut-off date. Most of such instances are covered under the 'change in law' or 'force majeure' events. Any additional capital expenditure would necessarily result in upward revision of tariff.

29.3.2 However, the beneficiaries and the long term customers often become aware of such tariff impact only when the generating company or the transmission licensee approaches the Commission for approval of such additional capital expenditure already incurred by them.

29.3.3 On the other hand, the generating company or the transmission licensee, which are required to incur such additional capital expenditure face uncertainty w.r.t regulatory approval and hence tariff recovery.

29.3.4 Therefore, the Commission has proposed for in-principle approval for additional capital expenditure above certain threshold limit, which will provide regulatory certainty to the generating company or transmission licensee on one side and provide advance notice to the beneficiaries or long term customers on the other . The proposed provision in the Draft Tariff Regulations are reproduced below.

"11. In-principle Approval in Specific circumstances: The generating company or the transmission licensee undertaking any additional capitalization on account of change in law events or force majeure conditions may file petition for in-principle approval for incurring such expenditure after prior notice to the beneficiaries or the long term customers, as the case may be, along with underlying assumptions, estimates and justification for such expenditure if the estimated expenditure exceeds 10% of the admitted capital cost of the project or Rs.100 Crore, whichever is lower."

29.4 Interim True-up

29.4.1 The Commission has proposed that truing up for tariff period 2019-24 shall be undertaken along with the tariff petition filed for the next tariff period. However, in case of a reasonable variation say 20% of change in AFC in projected additional capital expenditure or shifting of the timelines of such projected additional capital expenditure, there may be instances where annual fixed cost and the resulting tariff after truing up exercise may vary significantly.

29.4.2 In such case, the Commission has proposed for alternate option of interim true-up, in case of increase in tariff and refund to beneficiaries under notice to the Commission, in case of decrease in tariff. The proposed provision in the Draft Tariff Regulations are reproduced below.

"**13. Truing up of tariff for the period 2019-24 :** (1) The Commission shall carry out truing up exercise for the period 2019-24 along with the tariff petition filed for the next tariff period, for the following:

…….

(3) The generating company or the transmission licensee, as the case may be, may make an application for interim truing up of tariff in the year 2021-22, if the annual fixed cost increases by more than 20% over the annual fixed cost as determined by the Commission for the respective years of the tariff period.

Provided that if the actual additional capital expenditure falls short of the projected additional capital expenditure allowed under provisions of Chapter 7 of these regulations, the generating company or the transmission licensee, as the case may be, shall not be required to file any interim true up petition for this purpose and shall refund to the beneficiaries or the long term customers, as the case may be, the excess tariff recovered corresponding to the projected additional capital expenditure not incurred under intimation to the Commission at the bank rate as on 1st April of the respective years.

Provided further that the generating company or the transmission licensee shall submit the complete details along with the calculations of the refunds made to the beneficiaries or the long term customers, as the case may be, at the time of true up."