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PRAGATI POWER CORPORATION LIMITED
Corporate Identity Number (CIN) –U74899DL2001SGC 109135
(Regd. Off. - Himadri, Rajghat Power House Complex New Delhi- 110 002)
(Undertakings of Govt. of NCT of Delhi)
Tele Fax No. 011-23284797; Website: www.ipgcl-ppcl.gov.in

No. Comml./CERC/F.6/ 46 **Dated: 13.07.2018**

Secretary,
Central Electricity Regulatory Commission
3rd & 4th Floor Chandralok Building,
36, Janpath New Delhi – 110 001

Sub: **Terms & conditions for Tariff for the Tariff period commencing from 01.04.2019- Consultation paper thereof.**
Ref: **Public Notice No. L-1/236/2018/CERC dated 24th May, 2018**

Dear Sir,

This is in reference to above. In this regard it is to intimate that Pragati Power Corporation has 1371.2 MW falling under purview of Central Electricity Commission for determination of Tariff under clause - 61 of Electricity Act, 2003. In this regard, it is to mention that a general review of content of the draft paper indicates that various issues as addressed in the content are skewed to issues related to DISCOMS. Though the proposed tariff regulation is meant for generation and transmission companies.. Accordingly, comments / suggestions as notified in draft concerned documents/consultation paper for framing terms & conditions of Tariff relevant to Gas Turbine Power Stations have been furnished as under. The clauses of the consultation paper which have not been mentioned indicate that either same are not related to generation business of replying company or there is no comment to offer.

Chief (Fin)

S No.	Clause no. of Consultation paper	Issue indicated in consultation paper of Terms & conditions for Tariff period commencing from 01.04.2019	PPCL Comment
1	5.3.1	**5.3 Gas based Thermal Generation** 5.3.1 The Gas Based Thermal Generating Stations offer greater capability of ramping up and ramping down. Thus, gas based generating station can provide alternative source for balancing power to address the intermittency of renewable generation. However, the gas based generating stations having concluded PPA are facing problem due to shortage of supply of gas from domestic source. The alternative may be to source costlier gas either from spot market or R-LNG.	Apart from ramping up and ramping down characteristics of Gas Turbines, these have features of black start in case of black out / total grid failure. Therefore gas turbines are back bone of any grid. It has been proved in the past that gas turbines are only alternative at load centre to revive the grid after cascaded break outs. Therefore gas turbines needs to be made available even on costly gas like Spot -RLNG as cheaper domestic gas is not available for power generation in the priority hierarchy of Govt. of India.
2.	7.2.2 , 7.2.4 & 7.2.5	**7.2 Thermal Generating Stations –Tariff Structure** 7.2.2 In view of decreasing PLF of thermal generating stations, a need has been felt to look into two part tariff structure being followed now. As discussed in following paragraphs, inter alia, one option may be to introduce three part tariff structure. The two part tariff structure for generating station provides the right to use the infrastructure on payment of fixed component irrespective of quantum of electricity generated and the payment of energy cost for procuring each unit of electricity. However, with this tariff structure, following issues emerge. The two part tariff system	**7.2.4:** Certain part of this option is not feasible in case of power plant established under long terms power purchase agreement. **7.2.5**: Apart from depreciation required for repayment of loan, interest on loan & guaranteed return to extent of risk free return, employees cost and maintenance over head, expenditure on electricity, Insurance expenditure, license fee, statutory expenditure, water, Security expenses etc. are

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2.	7.2.2 , 7.2.4 & 7.2.5	**7.2 Thermal Generating Stations –Tariff Structure** 7.2.2 In view of decreasing PLF of thermal generating stations, a need has been felt to look into two part tariff structure being followed now. As discussed in following paragraphs, inter alia, one option may be to introduce three part tariff structure. The two part tariff structure for generating station provides the right to use the infrastructure on payment of fixed component irrespective of quantum of electricity generated and the payment of energy cost for procuring each unit of electricity. However, with this tariff structure, following issues emerge. The two part tariff system	**7.2.4**: Certain part of this option is not feasible in case of power plant established under long terms power purchase agreement. **7.2.5**: Apart from depreciation required for repayment of loan, interest on loan & guaranteed return to extent of risk free return, employees cost and maintenance over head, expenditure on electricity, Insurance expenditure, license fee, statutory expenditure, water, Security expenses etc. are

		structure is suitable when the demand for power ensures utilization of capacity up to or around the target availability. It allows the procurer to get electricity at reasonable per unit cost through optimum utilization of asset. Two part tariff operates well in power deficit scenario. Due to low demand, coal based power plants are running at a PLF of around 60%. Consequently, States have not been coming forward for long term power purchase to avoid fixed cost liability and rather they have been resorting to short term power purchase to meet their demand. 7.2.4 The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand. 7.2.5 The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch	also fixed in nature. Therefore it should be included under fixed obligations.
3	**7.3.4**	**7.3 Thermal Generating Stations – Older than 25 years** A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) Extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.	The gas turbine power stations need also to be considered for considering further operation beyond 25 years. As the gas turbines have the capability of faster ramping up and ramping down, black start and radial feeding option in case of total grid failures. Therefore, all the gas turbines plans older than 25 years of useful life and equipped with black start facilities and radial feeding options needs to be considered for i) Replacement of older generation gas turbines with higher efficiency modern series of gas turbine to the capacity nearer to present capacity. In view to utilize present allocation of cheaper gas with better options ii) Extension of useful life of these gas turbines with suitable capex for important and deteriorated parts.
	7.6.4	In case of integration of the renewable generation with the coal/ lignite based thermal power plant, the following may the alternatives.	The Gas turbine power stations need also to be integrated with renewal energy alternatives for blending the power generation from gas turbines and solar PV plants installed on available roof tops, walk ways, & extended projections of WHRB. The cost of tariff should be weighted average cost of both gas turbines

			generation & solar renewal energy generation. However, the part of solar energy needs to be accounted as part of auxiliary consumption in line with PAT Regulation. As as per PAT Regulation presently the energy generated and consumed at a power station is subtracted from total auxiliary consumption.
4	**8.2**	**Section 61** of the Act provides that the Commission shall be guided by the factors which would encourage competition and recovery of the cost of electricity in a reasonable manner. The present market framework involves the competition for power procurement for securing power purchase agreement. Once the power purchase agreement is secured, there is no framework for competition of dispatch. The distribution licensees follow merit order based on the tariff agreed under PPA under Section 63 of the Act or the tariff determined by the Commission under section 62 of the Act	The power plants owned by Central and States Governments have been installed considering the future need of power at load centre to supply uninterrupted and reliable power avoiding uncertainly due to time and distances for availability of power. Accordingly, financial tied up have been done and long terms PPAs have been signed. Presently merit order dispatch has many flaws in it as it takes into consideration of available variable cost of individual plants while scheduling the power on variable cost in lower to higher value. This practice ignores impact of fixed cost, transmission losses & charges and the uncertainties of availabilities of power from a physically distant power plant. Once the issues are tackled and rational priority taking into consideration of all parameters are considered. The power from the load centre located power plants will get prioritized. This can be achieved by modern prioritisation method by use of analytical hierarchy process (AHP) for multi constraints decision making for power scheduling.
5	**8.3 & 8.4**	**Deviation from Norms** **8.3** For various reasons, out of tied up capacity by the distribution licensee, some of the capacity often remains un-dispatched over large part of the year. Since the tariff determined by the Commission acts as ceiling, there is no embargo on the generating stations or the transmission licensee to charge lower tariff. This provides a scope for creating some competition. **8.4 Options for Regulatory Framework** Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.	**8.3:** Once more logical scheduling on merit order considering all parameters is taken care. The issue of un-dispatched power will get addressed. Further, the CERC regulations for URS and RRAP have already provisions to utilize un dispatched power. Therefore, instead of considering new provisions i.e. varying tariffs to create competitions. The provisions of URS and RRAS needs to be integrated with proposed draft regulations for FY 2019 to 2024. **8.4:** The dispatch of power plant in the station is not in purview of generator and the same lies with NRLDC/SLDC .Therefore, generator

			should not be dis- incentivized due to act of others.
6	**10.6,10.7 & 10.8**	**10. Gas based Thermal Generations** 10.6 The use of gas based generating station is important because of possibility of immediate ramp up and ramp down for balancing the variations of renewable generation. **Options for Regulatory framework** 10.7 Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required. **Comment**/ Suggestions 10.8 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.	**10.6:** This option needs to be exercised for the gas turbines with any type of available fuel for running gas turbines regardless of cost of generations as the gas turbines are back-bone of the grid and have features of faster ramp up and ramp down facility, black start facility and provisions of operation in islanding mode.
7	**11.1 to 11.10**	**11 Capital cost** The principles of tariff determination as per the Act mandate balancing of consumer's interest while allowing reasonable cost to the generator. The capital cost has a direct correlation with the cost of value chain of fixed charges and therefore the Commission always endeavors to allow capital cost after prudence check. The Tariff Policy, 2016 stipulates that the Appropriate Commission would evolve benchmark of capital cost as reference to allow reasonable capital cost to the generators or transmission licensees **Options for Regulatory Framework** 11.8 One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost. 11.9 Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on	The capital cost estimated based on investment approval can not be used to limit return on normative equity deployed as at initial stages of project, future variable of cost components like inflation, exchange rate and actual price of plant and equipment is not known. The estimation is based upon historical data with suitable escalation of material and labor index. There is no full proof method of prediction of cost escalation till COD of the plant from the zero date. Therefore, instead of framing new provisions of incentive & disincentive for timely and delayed commissioning of projects the existing provisions and practice needs to be integrated.

		additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced. **Comments/ Suggestions** 11.10 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any	
8	**13.1 & 13.2**	**Financial Parameters** 13.1 The performance based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weight-age may be provided for normative parameters to induce greater efficiency during operation as well as in development phase. **Comments/ Suggestions** 13.2 Comments and suggestions are invited from the stakeholders for continuation of normative approach for specifying financial parameters and alternatives, if any.	The normative value for return on equity, operation and maintenance expenses and interest of working capital needs to be maintained at present form. There are already provisions in present regulation to restrict recovery of above tariff components based upon actual availability of the plant. Once, normative parameters are allowed on pro-rata basis of availability there is no further need for additional weight age to induce further efficiency.
9	**14.3, to 14.7**	**Depreciation** **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 re-assessment 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	14.6 a). 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. 14.6 c). The assessment of balance useful life is tedious process involves lot of expenditures, may not be feasible in real time basis. Therefore, admissibility of additional expenditure for important items / equipments 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 extent the existing PPA of the power plants to existing beneficiaries

		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). **Comments/** Suggestions 14.7 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.	
10	**15.1 to 15.3**	**Gross Fixed Asset (GFA) Approach** 15.1 The Commission in the previous Tariff Regulations 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. **Option for Regulatory Framework** 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. **Comments/ Suggestions** 15.3 Comments and suggestions are invited from the stakeholders on any other possible regulatory options or to continue with the existing mechanism.	Since as per CEA estimates no new coal based capacity is envisaged till 2027 due to addition of renewal capacity during the period. The addition of renewal capacity requires balancing / smoothing generation to meet required level of demand due to varying nature of generation from solar and wind. Therefore, as mentioned in the present consultation paper due to its very nature of fast ramping up and ramping down, the gas turbines are to be promoted. Accordingly, it is necessary to maintain generation from existing gas turbine stations even on spot RLNG to optimum level by arranging to run gas turbines as pooled stations at regional level.
11	**16.1 to 16.5**	**Debt:Equity Ratio** 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% (upto 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** 16.4 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. Comments/ Suggestions 16.5 Comments and suggestions are invited from the stakeholders on the possible regulatory options	16.1 -16.5. The higher fractions of equity will insure committed level of involvement from the generator. Therefore, any dilution of fraction of equity for more involvement of financial market in terms of providing loan may lead to vicious circle. Therefore, dilution of fraction of equity and associated return thereof may not be fruitful in the long run.

		discussed above and alternate options, if any	
12	**17.2 to 17.4**	**17. Return on Investment** 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 have suggested for continuing the existing ROE approach." **Comments/ Suggestions** 17.4 Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any.	17.1-17.4. The explanatory memorandum for Central Commission while deciding Tariff Regulations for FY 2014-19 is still valid as there is acute shortage of fuel especially gas for running gas turbines. The interest rate is fluctuating. The financial health of generation companies including replying generator is not healthy due to default in payment by DISCOMS. Therefore, method of ROE in replace of ROCE should be continued.
13	**18.1 to 18.8**	**18. Rate of Return on Equity** **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,	The Power generation sector is capital intensive, involves huge initial capital associated with lot of commitment and risk. Therefore, any dilution to rate of ROE may lead to reduction in developer's interest. The smaller capacity plant with lesser capital expenditure should be provided with reasonable amount of return as the equity portion is very

		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;** **Comments/ Suggestions** 18.8 Comments and suggestions are invited from the stakeholders on the possible options discussed above and alternate options, if any.	small. Therefore, higher rate of return should be considered in order to maintain the interest of developer's in generation market.
14	**19.1 to 19.6**	**19. Cost of Debt** 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. **Options for Regulatory Framework** 19.4 While allowing the cost of debt as pass through, options available for regulatory framework	19.1-19.6: In this regard, it is important to note that cost of debt is liability of the developers towards financer which is actually being charged by lender. Therefore, any changes in the interest rate methodology should be such that it is passed through. The present provision existing in tariff regulation 2014-19 may be continued as it has provision to incentivize developers in case restructuring or refinancing of loan at lesser rate of interest is done. However, in order to make it more attractive for developers to go for restructuring or refinancing of existing loan and incentive work , a provision of retaining benefit in the

		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; **Comments/ Suggestions** 19.6 Comment and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate, if any.	ratio of 1:3 as compared to 2:1 as provided in CERC Regulation clause - 26 (7) of 2014-19 may be considered.
15	20.2to 20.4	**20 Interest on Working Capital (IOWC)** 20.2 The Reserve Bank of India (RBI), vide ref. RBI/2015-16/273 DBR.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. **Options for Regulatory Framework** 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	20.3 & 4: The normative working capital an interest thereof has been considered one of the components of the tariff in view that internal resources are not available for meeting out working capital requirement. The rate of short terms borrowing for working capital requirement due to eroding credit limits of developers as many of the beneficiaries are defaulting in payment in energy bills. Therefore, linking of working capital estimates on PLF basis rather than target availability basis may lead to non-availability of funds for day to day requirements. This may result in reducing availability and security of the grid. Similarly, the maintenance spare which are required in real time basis if excluded from O & M expenses for calculation of amount of working capital may lead to under estimation of working capital. Though, a logical estimation of Maintenance spares required for

		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. **Comments/ Suggestions** 20.4 Comments and suggestions are invited from the stakeholders on the regulatory options discussed above and alternate, if any.	day to day maintenance of the plant is need of the hour. However, while estimating various spares the technology of the plant, size of the plant and present useful life may be considered. The small capacity and old technology, plant need frequent maintenance and higher amount of spares..
16	21.3 to 21.8	21 Operation and Maintenance (O&M) expenses 21.3 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 review. 21.5 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. Rationalization similar to generating stations could be considered for the transmission system where the generating stations receive lower amount towards O&M expenses in case of addition of units in same generating stations as stated above. At the same time, different multiplying factor can be prescribed for different unit sizes even in case of the generating stations. 21.6 The O&M expenses of a generating station	**21.7 (a) -(g):** In case present escalation methodology of O & M expenditure considering variation in WPI & CPI is continued the same needs to be reviewed and revised taking into effect of pay revisions of direct employees, pay revision of security employees in case the same is availed by deploying third party i.e. CISF. It is important to note that due to prolonged frequent start and stop of gas turbine, it leads to faster deterioration rather than continuous running and occasional stoppages. Though, it is correct that continuous running and procedural stoppages of gas turbines reaches at faster rate to scheduled HGPI (Hot gas path inspection) and MI (Major Inspection) at the same time also correct that frequent start and stop of gas turbines, which is phenomena of the day, leads to higher

		generally increase with increase in the life completed by it. That is to say, the new plants requires less O&M expenses whereas old plants requires higher O&M expenses. Specifying generic norms for O&M expenses for all plants irrespective of its life may need a relook. **Options for Regulatory Framework** 21.7 (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). (e) 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; (f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. (g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost. **Comments/ Suggestions** 21.8 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate, if any.	deterioration factor, hence, more faster rate of reaching to scheduled HGPI and MI as compared to normal operation of Gas Turbines. Therefore, decision of reducing O & M of gas turbines being operated at lower level in gas / Neptha RLNG needs to be reviewed in line with OEM (Original Equipment Manufacturer) manual /procedure for scheduled overhauling of these gas turbines. Further, it is also important to note that the advance class gas turbine of higher capacity and efficiency like Pragati_III Bawana, Ratnagiri, Uno Sujan and OTPC Tripura need specialized maintenance. However, the technology and expertise of such specialized maintenance is not available in India till date. Therefore, additional O& M to meet out LTSA (long terms service agreement) / LTMA (long terms maintenance agreement) have been provided by CERC in present regulation for FY 2014-19. The same needs to be continued for advance technology gas turbines of such type till expertise for indigenous maintenance and overhauling is developed.
17	24.1 to 24.6	**24. Fuel - Landed Cost** 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	The landed fuel cost has various components some of them i.e. sizing charges, cleansing charges, washing charges, surface transport charges royalty, marketing margin, sale tax and GST are some of the known components of present fuel cost. However some of the components which may be imposed on account of less (Gas and coal) delayed (coal) and over consumption (in case of gases fuel) may lead to additional cost of fuel due to clauses of MCQ (Minimum contract quantity) consumption clause prevailing in coal

		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.	and gas supply agreement, being supplier's market. Therefore, possible impact of less fuel consumption than contracted need also be considered in total/landed cost of fuel.
18	25.1 to 25.3	**25. Fuel - Alternate Source** 25.1 The present regulatory framework provides that the generators resorting the alternate source of fuel, other than designated fuel supply agreement, require prior consultation only if the energy charge rate exceeds 30% of the base energy charge rate or 20% of energy charge rate of the previous month. These provisions were introduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time. **Options for Regulatory Framework** 25.2 (a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate; (b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014. **Comments/ Suggestions** 25.3 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternate options, if any.	25.3. Presently, fuel, especially gas is scares commodity. The Power Sector has been placed by MOPNG (Ministry of Petroleum and Gas) at lower priority as compared to fertilizer and transport. Therefore, availability of domestic gas and cheaper domestic gas is major issue. The gas allocation to the plant has frequent cuts and fluctuations. Therefore, while deciding on the issue of alternative fuel, the gas turbines needs to be treated separately and differently. In case present proposal of considering gas turbines stations as regional pool stations gets materialized. Further, as noted in clause 5.3.1 of the consultation paper, the alternative fuel of spot or RLNG should be allowed to gas turbine without any sealing limits of cost of fuel as proposed in present clause.
19	26.3.1 to 26.3.19	**26. Operational Norms (for Gas Power station is not given)** Station Heat Rate Auxiliary Energy Consumption Normative Annual Plant Availability	26. The norms for PLF, target availability, station heat rate and auxiliary consumption needs to be maintained as per present methodology. However, as given clause 26.3.10 of the consultation paper apart from Colony power, the power consumed by Station from the renewal energy resources installed in the power plant as per PAT regulation needs also to be excluded from auxiliary consumption while arriving effective auxiliary

			consumption of the plant. It is also important to note that presently due to frequent start and stop, partial load operation and prolonged backing down of the plant the percentage of auxiliary consumption of the station has gone very high. 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. It is also important to mention 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 in the proposed regulations for the issues as addressed above needs to be taken care of.
20	27.1 to 27.6	**27. Incentive** 27.4 In view of the introduction of the compensation mechanism for operating plants below norms i.e.83-85%, there may be a need to review the incentive and disincentive mechanism with reference to operational norms Options for Regulatory Framework 27.5 (a) Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations; (b) Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered. (c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms. (d) Review the norms for availability of transmission system.	27.5 (c): The allowance of compensation for deterioration of heat rate and auxiliary consumption of the station is not under part of action / in-action by the generator. The compensation is to indemnify the generator in terms of loss of fuel which is not recoverable from the beneficiary. Though the same is caused due to act of beneficiary or by the NRLDC/ SLDC on the decision of requisition of reduced amount of power scheduling by the beneficiary of the station. Thus, the compensation mechanism is analogous to insurance policy were the owner of the policy is compensated for any loss due to act of third party. However, incentive and disincentive are reward / punishment in terms of money provided to the developers / generators for its own act / actions. The compensation is never in full to restores the losses in case of plant. The present compensation mechanism only insures recovery of

		Comments/ Suggestions 27.6 Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.	part of fuel expenditure rather than full cost recovery. As on the occurrence of causes of compensation developer / generator has no intention to cause the effect. Therefore, while reviewing incentive and disincentive in view of existing compensation mechanism above submissions is to be taken care of.
21	28.1 to 28.2	**28. Implementation of Operational Norms** 28.1 The new tariff regulations take effect from 1st April of the tariff period. The Tariff Regulations require the generating company or transmission licensee to file the petitions within 180 days from the date of notification of the regulations. Since the tariff determination is quasi-judicial function, there is a time lag between filing the petition and finalization/ issuance of tariff order. Till the issuance of final order, the generating company or the transmission licenses keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months. Comments/ Suggestions 28.2 Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	28.2. In this regard, in order to reduce carrying cost for over or under recovery from both side either from generator or beneficiary, the tariff for billing purpose (fixed cost) should be considered for financial component. However, new norms of present / new regulation need to be considered for variable charges. This method will minimize the monetary losses / opportunity cost to either side in delaying, in passing benefit / effect of new regulation norms due to delayed decision of Central Commission.
22	29.1 to 29.3	**29. Sharing of gains in case of Controllable Parameters** 29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation	29 .1- 29.3: In line with reconciliation of energy bills and fuel charges thereof the same needs to be done on annual basis by May every year. Any compensation for controllable parameters should be allowed on annual weighted average basis, analogous to present recovery of capacity charges as provided at Regulation 2014-19.

		mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed. 29.2 The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF. 29.3 Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.	
23	30	**30. Late Payment Surcharge & Rebate** 30.1 The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR. 30.2 Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (Email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.	30.1. In view of continuous default in release of payment by beneficiaries any attempt to reduce LPSC and linking the same with MCLR may reduce financial credibility of the developer/generator. The working capital loan may not be available to generator due to its eroded financial credibility on account of accumulated outstanding. Therefore, the present system should have provisions of penal surcharge over and above normative surcharge beyond a given time period of default. Apart from above the attempt should be to make such provisions that beneficiary do not default in making payment of energy bills of generators due to reasons to attributed to them. This is possible only with higher and harsh penal charges analogous to DSM (Deviation settlement mechanism) provisions. **Moreover the beneficiaries defaulting after certain time period should not be allowed to purchase power and wheel through existing network of the grid. For that matter DISCOMS after default in payment after certain period of time for generator and transmission companies should not be allowed to avail alternate source of power purchase.**

			30.2. As regards to rebate on prompt payment of energy bills the same should be allowed within 24 hours of receiving the bills through e-mails. Though the existing regulation has provision for rebate only in case payment is made through LC. However, due to advent of technology adaption of cash less, on line transaction policy of Govt. of India, issue of delay in form of presentation of physical copy of the bill, authorized signatory two working days, holiday have become meaningless.
24	34.1 to 34.4	34.1 34.2 34.3 The scheduling and dispatch mechanism of renewable generation can be as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable Capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff. The rate of return, land cost, operation and maintenance cost for such renewable capacity canbe specified separately. **Comments/ Suggestions** 34.4 Comments and suggestions are invited from the stakeholders on the possible Optons for bundling tariff, and alternative options, if any.	**34.4: T**he gas turbine power stations should also be included in the list of existing thermal stations for renewal energy generation integration from solar PV based plant. The amount of power generating needs to be reduced equivalent to auxiliary energy consumption in line with PAT regulation.
25	37	**Alternative Approach to Tariff Design** 37.5 This variation could be attributed to many factors such as cost of land & site development, project specific Sub/Super critical status of the Plant, technology & equipment and material handling system which includes distance from the Coal Mine etc. In case of COD delay, Interest during construction, financing charges, taxes and duties etc. might have impacted the total project cost. This high variation indicates a need to conduct a more rigorous component-wise analysis of Capital cost for generation as well as transmission projects and understand the deviation to figure out appropriate benchmark capital cost for thermal generation stations **Views and comments are therefore being solicited on the following questions:** Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost? What are the variables that should be considered for the purpose of determining Capital Cost on normative basis? Any other methodology for benchmarking the capital cost for generation and transmission	Availability of bench mark cost for the new and older plant considering all effect of technology age and vintage is need of hour. The Central Commission already practicing the norms for bench mark capital cost in case of various type of renewal energy i.e solar PV, solar thermal, wind, bio-mas, bio-gas, hydro and MSW plants etc. therefore, provisions of bench marking cost for various technologies of power plant will avoid analysis and examination of large amount data in arriving AFC of the plant. This will also reduce the time taken in tariff determination process and the issue as discussed in para- 29 of consultation paper will also get addressed as the tariff will be determined as faster rate and will be available at the beginning of MYT period.

		projects? Normative Tariff by fixing AFC as a percentage of Capital Cost 37.7 As the next potential option for determination of tariff on normative basis, the possibility of fixing total AFC as a percentage of initial capital cost, is explored. In this context, sample size of 30 generating stations was examined to analyze the AFC of first year of operation as a percentage of the approved capital cost. It was observed that correlation coefficient between AFC approved for the first year of operation and approved capital cost was around 0.84. Similarly, correlation coefficient between average AFC approved per year (till FY 2016-17) and capital cost was 0.95. The significant correlation between AFC and capital cost indicates the possibility of benchmarking AFC as percentage of capital cost to save resources and time spent on conducting component wise prudence check. However, a further analysis showed Mean of AFC as percentage of Capital Cost as 22.55% and standard deviation for the distribution was as high as 7.17%. 37.8 The available data and the connected analysis highlights the necessity for a larger database facilitating bigger cluster-wise sample sizes and a more rigorous exercise, which could possibly facilitate drawing conclusions about whether AFC could be normatively determined by considering it as a percentage of capital cost. **In this regard, views/ comments are solicited on the following:-** Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis? What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?	
26	38.1	**38 Transparency in Billing and Accounting of Fuel** 38.1 The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.	38.1. There is already provision in existing tariff regulation to post the details of fuel including copy of paid fuel bills as per form- 15 of tariff Regulation 2014. Accordingly, it is felt that present provision of CERC is sufficient to insure transparency in bill and accounting of fuel.
27	39.1	**39 Relaxation of Norms** 39.1 The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features such as FGD, Desalination plant, increase in length of water conductor system etc may lead to power consumption in excess of the norms. In such	39.1. The relaxation of norms provisions needs to be provided in proposed regulations as there are different issues and compliance of norms, availing of facilities for land and water for installing of power plant for case to case basis.

		situations, the present regulatory framework provides for relaxation of norms. **Comments/ Suggestions** 39.2 Comments and suggestions are invited on whether to continue with the practice or change the parameters during the intervening stage.	
28	40.1 to 40.3	**40 Merit Order Operation** 40.1 Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high. 40.2 The merit order operation is important for economic operation of the plants and optimum dispatch of economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the dispatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle. **Comments/ Suggestions** 40.3 Comments and Suggestions are invited from the stakeholders for alternative approach, if any, for economic operation of merit order.	40.3. The present methodology of merit order dispatch based upon ECR is erratic as the methodology does not consider factor of distance, transmission losses and charges, advantage of load centre, generating station, over distant located power plants. Therefore, above factors needs to be considered while considering merit order dispatch. It is also suggested to use AHP (analytical hierarchy process) to include quantitative and qualitative parameters both while deciding priority and merit order dispatch.
29	42.1	**42 Goods and Service Tax (GST)** 42.1 Goods and Services Tax (GST) has been introduced which has replaced various Central and State level taxes. Accordingly, prudence check of impact of pre- GST and post-GST taxation regime on the costs may be required for determination of tariff in the next control period.	42.1. GST along with other future taxes may be allowed to pass through to the beneficiary.

In this regard, it is also requested that earlier submission of PPCL in NRPC held on 14.03.2018 may also be considered , in addition to present submission.

Thanking you,

Yours faithfully,

(Jagdish Kumar)
Director (Tech.)

Copy to: **(For Kind Information Pl.)**

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