S/86/2018/CRU. CERC

BSES

BSES Yamuna Power Limited

Shakti Kiran Building, Karkardooma
Delhi - 110032, India
CIN : U40109DL2001PLC111525
Tel.: +91 11 3999 9808, 3999 7111
Fax: +91 11 3999 9765
www.bsesdelhi.com

Ref: RA/BYPL/2018-19/83

Date: 13 July 2018

To,

The Secretary

Central Electricity Regulatory Commission,

3rd&4th Floor, Chandralok Building, Janpath

New Delhi - 110001

Subject: BYPL Comments on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 – Consultation Paper thereof.

Ref: Hon'ble CERC public notice dated 24.05.2018

Dear Sir,

We write in reference to the Hon'ble CERC public notice on consultation paper on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019

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

Thanking you,

Your sincerely,

Gagan B Swain

Head-Regulatory Affairs

Encl: As above (3-sets)

Sl. No	Proposed	Ref.	Comments
1	**Fixed Charges** 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 tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel). 7.2.6 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.	7.2.4-7.2.6	Apportionment of components of Fixed cost in Fixed and variable component needs more clarity. (O&M cost and return ratios to be clarified) and may be done as follows: 1) Depreciation – 100% on availability 2) ROE- upto FD rate about 8% to be linked to availability balance (14.5%-8%) i.e ROE-FD rate linked with the dispatch 3) Interest on WIC - 100% linked to the dispatch 4) Interest on loan - 100% on availability 5) O&M – 50% on availability 50% on dispatch We assume 50% out of O&M expense is pertaining to employee salary excluding incentives 6) Less: Non Tariff Income such as LPSC beyond financing cost, Sale of Scrap, Sale of fly Ash etc.- 100% on availability
2	**Thermal Generating Stations – Older than 25 years** 7.3.4 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		1) Discom's PPA with Genco's are mostly with NTPC which is till phase out of the unit, CERC may provide a suitable guideline so that discom may have an option to amend/exit the existing PPA's of plants older than 25 years. The extension of life period of the plant or R&M of the

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	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.		plants etc.are to be guided by a specific regulation/guidelines acceptable to the all stakeholders. The broad parameters for consideration of extension of lifetime over R&M expenses etc need to cover the followings; i) The comparative cost of the generation vis-à-vis price of the medium term power available in the market. While comparing the cost of the impact of REC needs to be adjusted to the cost of fossil fuel plant as it is preferable to have renewable sources which will help in complying the RPO as well the energy requirement ii) Prior consultation with beneficiary before R&M work/extension of useful life . iii) Efficiency of the plant and corbon emissions. 2) Also in view of the mandate of Tariff policy 2016 Discom have to arrange majority of its power requirement from Renewable stations, therefore it is submitted that old and inefficient Genco's having age more than 25 years may be phased out.
3	**GCV** 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	5.8.3 22.8 (a,b,c)	***We appreciate CERC for its view on GCV , following issues may also be considered:*** 1)As per the CAG report as well as CEA there would be minor loss of GCV in as billed to as received to as fired value:

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	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.		Para 5.2 of CAG report : *"5.2 Reduction in heat value (GCV) of coal……It was observed that GCV of coal progressively decreased from the 'as billed' stage to the 'as fired' stage, though as per CEA, the three GCV values, i.e., GCV 'as billed', 'as received' and 'as fired' should be approximately same barring minor losses due to storage……"* Therefore there must be a minor difference between as loaded and as received GCV values. 2) CEA also prescribed loss of GCV in its Recommendation on operational norms of Thermal Power stations tariff Period 2014-2019 as under; *"…..Para 13.4 It may be pertinent to mention that the* ***billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as "as received GCV").*** *Considering the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and as received GCV; however, difference between the as received GCV vis-à-vis "as fired GCV" would be very marginal and would be solely on account of marginal loss of heat during the coal storage…* *3)* Further the MoP has proposed 3rd party sampling. However the Genco's need to be directed to share the test reports of the coal as submitted by the 3rd part agencies to the

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			beneficiaries as well as publish the same on their website. The 3rd party sampling procedure also need to involve the representatives of the beneficiaries to verify the independence and correctness of 3rd party sampling. 4. The FSA with the coal companies provide for the delivery point to the Generator at the mine end. Hence once the property in goods passes to the Generator, it is the Generator which is liable to account for any drop in GCV thereafter, Hence the GCV as recorded at the mine end minus the existing normative transportation losses must be considered for billing to the beneficiaries. 5. Further the normative loss as per CEA report is of 80 Kcal as prescribed for 30 days storage kept as inventory in the plant. Similarly if the time taken for loading and transportation from the colliery to the plant takes 10 days time another about 25 Kcal normative loss in GCV can be added. Therefore is the billed GCV is 5500 Kcal then the GCV to be used for computation of energy charges to be considered as 5395 (5500-80-25) Kcal
4	**Fuel - Blending of Imported Coal and Fuel Landed cost** **Alternative Source of Coal** 23: Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	5.8.6-8 23 and 24.1-24.6	On Para 23 1) Commission may initiate a methodology to work out the normative / agreed blending ratio for existing projects and new projects, based on the cost of the imported coal, GCV and the ratio of blending, operating hours of the unit/station. Pit-

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	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.		head Stations may not be allowed for blending of imported/e-auction coal. However, the consent of the beneficiary may be made mandatory before carrying out any sort of blending of coal. Further in case any blending is done it must reduce the fuel cost rather than increasing it. Alternate Source: 1) Gencos need to take consent/ Prior intimation from the beneficiaries before 15 days of using the coal for generation, if the variable charges are increasing more than 5% vis a vis the rate for previous month so as to enable the beneficiaries to schedule there power on MOD principle. With change in blending ratios the MOD ranking of different Genco's changes and without information to Discom's it is impossible to schedule as per actual MoD, DERC has imposed heavy penalty about Rs 100 Cr for deviating the MoD Principle. On Para 24 1) In order to optimize the landed cost of fuel, Fuel supply agreement to be provided by Generator's to the beneficiary's 2) Penalty clause to be incorporated in Generator FSA agreement with coal companies. (*Delay in transportation/Quality of coal).*

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			3) On the day of receipt of the form-15 complete data to be recognized as the bill date for availing the rebate as well as consideration of LPSC charges. The revised Proposed Form-15 is attached as Annexure-2
5	10.3 (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; (b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	10.3(B)	1) This approach will encourage competition and will result in optimum utilisation of natural resources. 2) Also similar methodology may be adopted for unutilised capacity of Transmission system.
6	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	11 (Capital Cost)	i) The existing regulations do not provide for any investment approval. The last regulation that provided for investment approval were the 2004-09 regulations, Since the 2014-19 regulations do not provide for investment approval, there ought to be no occasions to move away from it.

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	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 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.		ii) Without prejudice to the above while framing the benchmark capex norms, The Construction period may be standardized to avoid increase in capital cost on account of IDC, escalation in prices and increase in establishment charge. Before inserting the provisions for standardization of construction period, the zero date or the starting date of the project needs to be defined explicitly. ii) The disincentive for any time and Cost overrun resulting in slippage from scheduled commissioning to be introduced and same may be reduced from the Capital cost of the plant.
7	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 Renovation & Modernisation (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	12 (R&M)	**i**) Transmission companies should file claims along with detailed project report and prior consent for R&M in consultation with the beneficiaries. ii) A detailed technical study of the Transmission assets should be undertaken every five years, after the completion of initial 25 years of the transmission line. Based on the diagnostic study, R&M scheme should be prepared by an independent body giving a cost benefit analysis numerating in detail impact on operational performance and on life of the Transmission Asset.
8	...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	14. Depreciation	CERC may decide suitably after analysis i) Life of Thermal plants extend from 25 to 35 yrs ii) Life of hydro plants/transmission extended from 35 to 50 yrs.

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	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).		CEA being a technical apex body should be consulted. Further the balance depreciation after deducting recovered depreciation from 90% of GFA ought to be equally spread over the extended period so as to ensure tariffs go down. Reducing depreciation rates or extension of useful life should not lead to any additional expenses in any form as a pass through.
9	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	16. Debt equity ratio	i)The Debt Equity Ratio may be **revised to 80:20** for the reason that the beneficiaries will be required to pay a comparative lesser ROE. Further since Generation Utilites are better placed as compared to DISCOMs and therefore have lower risk equity portion may further be gradually reduced once the asset is completing its useful life. Viz. 15% , 5% and thereon. For eg. • Gross Value – Rs 1000 Cr • Accumulated Depreciation 85% • Net Value- Rs 150 Cr (20% equity Rs 30 Cr and balance 80% Rs 120 Cr as Debt) ii) For **existing projects**, the debt equity ratio may be considered to be 70:30.

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10	Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any	17. RoCE	ROE should be continued but the rate of return ought to be reviewed in the light of present and future economic scenario's
11	(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;	18. ROE	Yes we agree that the ROE should be reviewed i) In case of the projects are commissioned after scheduled COD a penalty of 0.75% on existing ROE shall be imposed on such project
12	(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;	19. Cost of Debt	The existing method should continue, which assure the generators to recover actual rate of interest (on weighted average basis) in every year. And saving on interest shall be shared between the beneficiaries and utilities in the ration of 2:1.
13	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		As per clause 4 of regulation 28 of CERC tariff regulations 14-19, the IWC shall be payable on normative basis. The relevant clause has been reproduced below. *"(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."*

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	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...**		Since IWC is an integral part of AFC, it's essentially payable based on the DC of plant. ie if the plant availability factor is above 85% then the generating company is allowed to recover the entire IWC. However in the recent trend it's observed that the actual PLF of plants is considerably low in comparison to their plant availability factor leading to considerable savings for generating stations. Hence it's proposed to annually true-up IWC on PLF basis and savings should be passed to the beneficiaries as the generating companies risk with respect to operation at low PLF is hedged through compensation charges. In case of delays, interest should be applicable equivalent to LPSC rates.
14	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).	21. O&M expenses	As the O&M expenses are based on norms, The Commission may true up the O&M expenses within the overall limits of the norms and any saving on O&M expenses be shared equally with the beneficiaries. Further Benchmarking to be done with ultra mega plants and plants of international standards

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15	<u>**Transit & Handling losses**</u> 26.3.18 A regulatory option could be that the generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms. **This can be addressed in the Tariff Regulation by indicating GCV as "As Received at plant end" and customization of Form- 15 regarding the GCV.**	26.3.18	**1)** Penalty on Generating companies for not submitting form-15 in time as well as revision in ECR rate Further GCV should be as billed and not as received, also CEA has prescribed loss of GCV in its Recommendation on operational norms of Thermal Power stations tariff Period 2014-2019 as under; *"…..Para 13.4 It may be pertinent to mention that the* ***billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as "as received GCV").*** *Considering the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and as received GCV; however, difference between the as received GCV vis-à-vis "as fired GCV" would be very marginal and would be solely on account of marginal loss of heat during the coal storage…* 2) Penalty for submitting incomplete form-15. *3) On the day of receipt of the form-15 complete data to be recognized as the bill date for availing the rebate as well as consideration of LPSC charges.* **The revised Proposed Form-15 is attached as Annexure-2**

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16	**Station Heat Rate** 26.3.1 Station Heat rate (SHR) refers to the conversion efficiency of thermal heat energy into electrical energy and used for computation of energy charges. The heat rate norm specified during previous tariff periods are as under: Table 12 Comparison of SHR between 2009-14 and 2014-19 tariff periods 2009-14 Tariff Period 2014-19 Tariff Period 200/210/250 MW Sets - 2500 Kcal/kWh 200/210/250 MW Sets - 2425 Kcal/kWh 500MW and above - 2425 Kcal/kWh 500MW and above - 2375 Kcal/kWh 26.3.2 The GCV measurement of coal was shifted to “As Received” basis for the purpose of energy charges computation in the Tariff Regulations for the period 2014-19 **as per the advice of Central Electricity Authority.**		1) Based upon the recent trends on controllable parameters of SHR from the bills of Generating company there is a reduction of SHR of about 25 Kcal/Kwh (2425 to 2400), Therefore it is proposed to reduce the SHR by another 25 Kcal/Kwh 2)Further **CEA views may be considered for period FY 19-24 and option in para** 22.8 (a) required to be considered i.e *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.*
17	**<u>Incentive</u>** 27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods. On the same consideration, there may also be a need for higher incentive for the storage and pondage type hydro generating station providing peaking support. At present, generation beyond the design energy is paid at 80 Paise/kWh in case of hydro generating station, which may also need review. 27.4 In view of the introduction of the compensation mechanism for operating plants below norms i.e.83-85%, there may be a	27.2-5	Reply on 27.2 We also <u>propose to introduce disincentive on the similar lines during peak and off peak period when plant fails to achieve NAPAF</u>. Reply on 27.4 ii) Compensation mechanism on account of Technical minimum to be withdrawn based on following grounds.

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	need to review the incentive and disincentive mechanism with reference to operational norms. 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.		1) The present regulatory framework provides for sharing of gains between generating company and beneficiaries in ratio of 60:40, the same is on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption etc.. On the other hand the Generating company are also charging compensation to Discom's, on account of variation in actual schedule vis a vis target Availability, The compensation due to above results in increase in SHR in the range of (2.25%,4% ,6%) & Aux Power in the range of (0.35%,0.65% & 1%) respectively as per IEGC 5th Amendment Dated 12.04.2017. Therefore It is evident from above that the generating company are gaining on account of both scenario's Hence the Compensation mechanism needs to be withdrawn
18	**<u>Late payment surcharge</u>** 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.	30.1,2	1) Rate of late payment surcharge needs to be reviewed. As existing interest rates of banks have reduced drastically. Further it is suggested to determine a margin over and above MCLR to decide the LPSC rate for that year.

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	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.		2) Further any LPSC recovered by Genco/Transco above financing cost of LPSC must be considered as a part of Non Tariff income
19	**Non Tariff Income** 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.	31.1,2	1) Any LPSC recovered by Genco/Transco must be considered as a part of non Tariff income 2) The revenue from Telecom business must be in proportion of the transmission as per Section 41 of Electricity Act 2003, As at present the rate is fixed rate, such fixed rate is not in accordance with Section 41 of Electricity Act -2003. 3) Also Third party audit should be conducted to know the actual gain through telecoms income to PGCIL and it should be passed on to the beneficiaries
20	The merit order operation is important for economic operation of	40.2 MOD	The beneficiary here suffers in two ways:

Sl. No	Proposed	Ref.	Comments
	the plants and optimum despatch 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 despatch. 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.		1) In view of non availability of prior information of fuel from the Generators, Costlier plants could not be backed down which results in non adherence of MoD principles, recently DERC has imposed heavy penalty on Discom about Rs 100 Cr for deviating the MoD Principle.. 2) Further erroneous backing down of cheaper generation occurs as the actual variable cost of generation is not known due to lack of proper information on type of fuel (coal) used Hence it is suggested that since Generator has availability of 1month fuel stock therefore any adhoc procurement of fuel has to be displayed on generator website on real time basis, so as to avoid any doubts**.**

Additional Comments

Sl. No	Amendment Proposed	Ref.	Comments
21	**Transmission** **Two Part tariff:** 1. Fixed Charges (FC): Annual Fixed Cost of some of fixed transmission system designated for access and immediate evacuation, Annual Fixed Cost of evacuation transmission system, Part of annual fixed cost consisting of debt service obligations, interest on loans, guaranteed returns **2.** Variable Charges (VC): Common transmission	7.5.4-7.5.6	Large part of the transmission lines are being ideal in nature but not being utilized and entire cost is being put on DISCOMs which ultimately burdens the consumers. Therefore there is an urgent requirement to introduce two part tariff in Transmission system. On implementation of 2 Part Tariff in Transmission system, it is mandatory that NLC shall identify the transmission lines which are

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	system excluding evacuation transmission system; Sum of incremental return, O&M Expenses, Interest on working capital		allocated and utilized by the beneficiaries (with a valid MTA/ LTA) so that the fixed charges and variable charges towards the energy flown through respective lines can be charged from the beneficiaries.
22	Renewable **Two Part tariff:** i) Fixed Charges (FC): Debt Service Obligation and Depreciation Ii) Variable Charges (VC): O&M Expenses and ROE	7.6.3-7.6.4	1. In case there is a two part tariff in case of bundling RE power with conventional power stations, and the RE power plant is not able to generate due to environmental constraints, then energy received through conventional power to the extent of RE power scheduled by DISCOM should be considered towards RPO of DISCOM For example: a DISCOM schedules 400 MU from Conventional power to be generated by Anta Gas Station and 20 MU from RE power to be generated by Anta Gas Station and DISCOM actually received 410 MU only from conventional power of Anta Gas Station and 0 MU from RE power of Anta Gas Station then, 20 MU out of 410 MU should be considered as RE power received by DISCOM for meeting RPO and rest 390 MU towards conventional power of Anta Gas Station. Such a mechanism would ensure certainty. 2. Further in case of IPPs generating RE power only (not bundled with conventional sources), single part tariff should be continued so as to insulate DISCOM towards undue burdening of fixed charges when the DISCOM is actually not receivingany power or lesser power than scheduled power.

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			3. Further in case of bundled power, if RE power is scheduled by DISCOM but is actually not dispatched due to environmental constraints and DISCOM receives energy through conventional power in lieu of scheduled RE power, DISCOM must be liable to pay cost corresponding to RE power only and not conventional power.
23	**<u>Tariff Mechanism for Pollution Control System.</u>** The principle of bringing the generator to the same economic condition ifit is considered as change in Law. Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period; Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years. Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.	33	• 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 speculations the impact for implementation of norms is Rs. 0.30/kwh to Rs. 0.60/kwh depending upon the plant specifications. • Also, there is constraints on timely implementation of retrofitting on the same. As per CEA it is 2022 by which the retro-fitting is done whereas few generating stations also require more time to implement the same. • It is pre-mature to consider such a huge impact on the consumers' tariffs. Hence, as the implementation of the notification takes time the control period FY 2019-24 is complete. • Therefore, we request the Commission to consider the impact of such cost while Truing-up only. • Also, Gencos are having huge cash surplus which can easily manage to fund interim funds if required. • If at all in case of limited fund availability, then the Long term loan can be arranged and only interest cost can be recovered from

Sl. No	Amendment Proposed	Ref.	Comments
			Discoms/consumers. • Alternatively, being a responsible and most important link in the value chain of cost of supply to the consumers. Thermal generating stations should meet the Environment norms from its profits. • Without prejudice to the above, If at all the sharing is to be done then it should be in ratio of 50:50 between Gencos and consumers. Also, Thermal generating stations whose ECR is more than Rs. 2.50/unit should not be implemented, instead should be shut down/phased out.
24	**<u>RE Generation by existing Thermal Genco.</u>** • Install RE project at the same location using common facilities and land and bundle RE power with the conventional power prior to delivery point • Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond the delivery point. • However in both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles. • 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.		In view of proposed two part tariff on bundling of RE power with conventional power stations, and the RE power plant is not able to generate due to environmental constraints, then energy received through conventional power to the extent of RE power scheduled by Discom should be considered towards fulfillment of RPO of Discom. **<u>Illustration</u>**: a DISCOM schedules 400 MU from Conventional power to be generated by Anta Gas Station and 20 MU from RE power to be generated by Anta Gas Station and DISCOM actually received 410 MU only from conventional power of Anta Gas Station and 0 MU from RE power of Anta Gas Station then, 20 MU out of 410 MU should be considered as RE power received by DISCOM for meeting RPO and rest 390 MU towards conventional power of Anta Gas Station. Such a mechanism would ensure certainty.

Sl. No	Amendment Proposed	Ref.	Comments
			The Tariff of renewable and Thermal should not be bundled as this case increase complexity and litigations further. Tariff should be separate and it should be through TBCB route for renewable generation.

Additionally Genco's needs to provide Bills and Form-15 to Discom's in soft copy excel format/ any data base so as to utilise the same by all utilities for verification. It will save huge manpower cost across the sector, Further with regard to vulnerability of data the same may also be given in Acrobat format as a proof for future authentication.