5242/2018/CRU-CERC (4)

दादरा नगर हवेली उर्जा वितरण निगम लिमिटेड
(सरकार का उपक्रम)
DNH POWER DISTRIBUTION CORPORATION LTD.
(A Government Undertaking)
CIN : U40100DN2012GOI000405

DNHPDCL/2018/ 1921 Dt: 09/07/2018

To,
The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor,
Chandralok Building,
36, Janpath, New Delhi -110 001
☎: 011-23353503/23753918

Sub: **Comments on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 – Consultation Paper thereof issued by CERC vide public notice No. L-1/236/2018/CERC dated the 24th May' 2018**

Sir,

With reference to the above subject, please find attached herewith the comments of DNH Power Distribution Corporation Ltd., Silvassa, Dadra & Nagar Haveli for consideration while finalising the Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019. (3 copies)

Soft copy of the comments as mentioned above has been emailed to your id- info@cercind.gov.in

Thanking you,

Yours faithfully,

C. A. Parmar,
Chief Engineer, DNHPDCL

Chief Engineer
DNH Power Distribution Corporation Ltd.
U.T. of Dadra & Nagar Haveli, Silvassa

Encl: As above

Comments on Draft Amendments to Consultation Paper by CERC

5.2.10

So far in the previous tariff periods Hon'ble CERC allowed for additional capitalization by the project developers from COD till the cut-off date. The project developers are expected to file a petition with audited financial statements after the cut-off date before the commission for approval. In certain cases, capital expenditure may be required even after cut-off date. Some instances are relay replacements with new technology, commissioning of SCADA, telemetry, PMU etc. and equipment to comply with environmental norms and performance improvement etc. In such cases, the project developer has to obtain the concurrence of beneficiaries through regional power committees and there after obtain the approval of the commission. In cases where the project developer quantifies the gains likely to be obtained (in the project report) by spending additional CAPEX after cut-off date, Hon'ble commission may allow for carrying out such works without the consent of beneficiaries. Third party audit may be done to verify the claims of the project developer before approval of the commission. In no case IDC and IEDC shall be allowed after the COD. If generation / transmission developer has to carry out some works after COD, he should be penalized to the extent by not allowing additional 0.5% RoE for completion within target period. Due to the components like IDC and IEDC, any expenditure after CoD should not be normally permitted. The only way out is bench marking the project cost and this cost should be based on the project commissioned through competitive bidding route. Such benchmark cost should act as a ceiling.

5.4.1

The pass thru provision has to be removed. ***The Govt. owned companies and IPPs supplying 100% power to DISCOMs to through long terms PPAs were being allotted dedicated coal blocks, which will ensure availability of fuel and at reduced cost. With this arrangement, pass thru clause is not required.*** Two ways of determining the fuel cost may be evaluated. The commission may fix up normative cost by studying the past data and the cost of fuel should in any case be at least 50% cheaper due to reduction in overheads of CIL (Coal India Ltd.) and cost of rail transportation. Coal washaries can also be setup at the mine head. The second way of determining the cost of fuel is the cost plus approach with benchmarking. The fuel prices of coal (60% of the generation for the country coming from coal) affects the power tariff in significant way and thereby the procurement cost of the DISCOM adversely. It is advisable to have a common regulator for coal and power to sort out unilateral price raise by the coal companies. Till then it is preferable to have a common ministry for department of coal and department of power.

Allotment of coal blocks would result in low fuel price and high availability of fuel which may help in avoiding generation loss due to coal supply issues and cheaper fuel with better GCV (Gross Calorific Value) and loss of GCV before firing will be minimum. Hence, pass through clause can be removed.

Further, the generating company may procure fuel at high cost in case non-availability from the designated source or may use the blending with imported coal which may increase the fuel cost i.e., energy charges, thus impacting merit order procurement and merit order scheduling which are based on fuel cost / variable cost. At present, the available generation in the country is much higher that the demand and in most cases the distribution companies may not require additional generation from fuel purchase through e-auction or imported coal or higher level of blending. Therefore, the generating company should offer DC (Declared Capability) with designated fuel and additional DC with e-auction fuel and additional DC with likely blending ratio through imported coal. Thus, the choice lies with discoms to choose only DC with designated fuel or declared capabilities with other variates. There must be total choice in scheduling. There must be two levels of permissions to be obtained from beneficiaries / discoms – weekly permission for procurement through e-auction and blending through imported coal; day-ahead permission through requisition against various DCs offered, both options should be followed. An indicative price for each DC should be given to enable merit order requisition by the Discom. At present discoms are making huge losses as sources of power and price for various fuel wise DCs are not made available before the fact and sudden surprises seen after the fact when the monthly bills are presented. Such kind of authoritative hegemony by the generating companies should be prevented as discoms are helpless due to sole responsibility of providing 24x7 power supply rests with discoms.

5.5.3

Capital cost of hydro generation in Cr./MW need not always be higher than corresponding thermal generation due to factors like terrain, topography, geographical and seismic conditions etc. However, due to flexibility in operation in the context of high RE, hydro and pumped storage plants in particular shall be used for grid balancing and should be compensated adequately, even if the capital costs are high.

5.8.4 and 5.8.5

The generating company may procure fuel at high cost in case non-availability from the designated source or may use the blending with imported coal which may increase the fuel cost i.e., energy charges, thus impacting merit order procurement and merit order scheduling which are based on fuel cost / variable cost. At present, the available generation in the country is much higher that the demand and in most cases the distribution companies may not require additional generation from fuel purchase through e-auction or imported coal or higher level of blending. Therefore, the generating company should offer DC (Declared Capability) with designated fuel and additional DC with e-auction fuel and additional DC with likely blending ratio through imported coal. Thus, the choice lies with discoms to choose only DC with designated fuel or declared capabilities with other variates. There must be total choice in scheduling. There must be two levels of permissions to be obtained from beneficiaries / discoms – weekly permission for procurement through e-auction and blending through imported coal; day-ahead permission through requisition against various DCs offered, both options should be followed. An indicative price for each DC should be given to enable merit order requisition by the Discom. At present discoms are making huge losses as sources of power and price for various fuel wise DCs are not made available before the fact and sudden surprises seen after the fact when the monthly bills are presented. Such kind of authoritative hegemony by the generating companies should be prevented as discoms are helpless due to sole responsibility of providing 24x7 power supply rests with discoms.

5.8.6 to 5.8.8

As per the present regulations, the energy charges are directly pass through based on the formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. The beneficiaries verify the bills or claims of the energy charge rate while making payment.

In addition to using coal from captive coal blocks allocated by GoI, the generating company may procure fuel at high cost in case non-availability from the designated source or may use the blending with imported coal which may increase the fuel cost i.e., energy charges, thus impacting merit order procurement and merit order scheduling which are based on fuel cost / variable cost. At present, the available generation in the country is much higher that the demand and in most cases the distribution companies may not require additional generation from fuel purchase through e-auction or imported coal or higher level of blending. Therefore, the generating company should offer DC (Declared Capability) with designated fuel and additional DC with e-auction fuel and additional DC with likely blending ratio through imported coal. Thus, the choice lies with discoms to choose only DC with designated fuel or declared capabilities with other variates. There must be total choice in scheduling. There must be two levels of permissions to be obtained from beneficiaries / discoms – weekly permission for procurement through e-auction and blending through imported coal; day-ahead permission through requisition against various DCs offered, both options should be followed. An indicative price for each DC should be given to enable merit order requisition by the Discom. At present discoms are making huge losses as sources of power and price for various fuel wise DCs are not made available before the fact and sudden surprises seen after the fact when the monthly bills are presented. Such kind of authoritative hegemony by the generating companies should be prevented as discoms are helpless due to sole responsibility of providing 24x7 power supply rests with discoms.

In such complex arrangements of procuring the fuel, use of various transportation systems – rail, road, water transport, MGR, etc., variation of GCV and loss of heat at several points, it is difficult to verify various component costs out of the fuel cost. However, avoiding verification and allowing costs as pass through is not prudent. For the purpose of merit order requisition, the landed cost of fuel including blending ratio, costs source-wise of e-auction, imported coal etc. are required at the time of scheduling. Otherwise, merit order gets distorted. Hence, generating plant owner should be able to provide projected costs with an accuracy of 5% or a complex formula based on normative component costs to evaluate normative fuel cost.

7.2.1 to 7.2.6

In these sections, the consultation paper has proposed three part tariff with the following components,

a) Fixed Cost (FC) based on target availability
b) Variable part of fixed cost (VFC) based on the difference of availability and dispatch
c) Energy Charge (EC) reflecting fuel cost based on dispatch.

An example case is constructed to examine the efficacy of computations as described below,

Average DC for the day DCavg = $\frac{1}{96}\sum_{i=1}^{i=96} DC\ (i)$

Ex-Bus installed capacity XCap = Installed Capacity (1 – percentage normative auxiliary consumption / 100)

First compute normative availability factor for the day: DCavg / Xcap * 100

Assume target availability of 85% given by CERC. If target availability is less than 85%, fixed cost has to be recovered on pro-rata basis and at 85% or above 100% cost is recoverable.

Fixed cost to be recovered per day (AFC / 365 or 366) = 10 Cr for 1st April. Since availability computed for the day is higher than 85%, 10 Cr. is fully recoverable.

Cut-off PLF of 60% **assumed** and the same will be decided by CERC.

60% (i.e., 6 Cr.) AFC to recover through part – A above and 40% of AFC to be recovered through variable charge (i.e., 4 Cr.) part – B above.

Daily generation (MWH) = $\sum_{i=1}^{i=96} schedule\ (i)$

Compute scheduled PLF based on scheduled generation for the day as,

100*scheduled generation in MWH / (24 x Ex-Bus installed Capacity)

Ex-Bus installed capacity = Installed Capacity (1 – percentage normative auxiliary consumption / 100)

Compute schedule PLF for each of the beneficiary based on Ex-Bus entitlement. The variable cost has to be applied on those beneficiaries whose scheduled PLF requisition is more than 60%.

Energy in KWH of each beneficiary exceeding 60% PLF requisition say X1, X2, X3 KWH for three beneficiaries out of 5 total beneficiaries.

Part – A (6 Cr.) has to be booked on all the 5 beneficiaries in the ratio of their entitlements.

Part –B (4 Cr.) has to be booked on 3 beneficiaries in the ratio of X1:X2:X3.

The booking for 2 days for 1st and 2nd April is computed in a similar manner for 20 Cr cumulatively. Standalone charges for 2nd April can be computed by difference.

Incentive shall have to be calculated at the end of the month and payable only in case schedule PLF of the generator is > 85%.

Since the distribution companies are mostly loss making and generating companies have low schedules and operating at lower PLF than 85%, incentive payment to generators could be only for those days when the requisitions are more than 85% of the DC i.e., schedule from long term customers (firm beneficiaries) = > 0.85 DC. Only few generators become eligible for the incentive payments. World over most generators even do not recover full fixed cost on most of the days and part or full recovery possible only on those days when market prices are high due to high demand.

7.3.1 to 7.3.4

Thermal generators older than 25 years have fully recovered the capital cost and can carryon for at least another 10 years and the power is available to beneficiaries at a price equal to fuel charge plus O&M cost. With additional expenditure on R&M, useful life extension is possible and O&M cost can be controlled.

7.6.1

No bundling of renewable generation with conventional power generation to be considered. However, it is worthwhile to consider **bundling with energy storage options, hybrid RE, RTC-RE etc.**

7.6.2 and 7.6.3

RE generation should be procured only through competitive bidding and no feed-in tariff determination as it is seen in the recent years that prices obtained through competitive bidding are far less than feed-in tariffs. Feed-in tariffs / regulated tariff will give advantage to Govt. owned companies and eliminate competition in the sector. The principle of level playing field has to be ensured especially since power sector is in deep trouble with lots of stressed assets.

7.6.4 to 7.7.1

Since installed capacity of the country is around 365 GW while peak demand met is in the order of 170 GW, India has surplus generation and it is estimated that the demand growth forecasted by CEA do not warrant any additional requirement of thermal generation (coal / lignite) till 2027. Further, RE generation is likely to be added to the extent of 175000 MW by 2022 and the progress of RES addition is highly encouraging. In view of this, no coal / lignite need to be added further till next decade. Instead of encouraging bundled generation involving thermal + RE (which is likely to distort merit order) generation, India has to progressively move towards RTC-RE generation which can replace the conventional generation. We can also have bundled generation with Hybrid RE plus energy storage. Further, bundled power plants (thermal + RE) will lead to procurement of additional RE generation by existing thermal plant owners through regulated route rather than competitive bidding which will lead to higher costs and inefficiencies apart from merit order related issues.

Provided scheduling and despatch of such conventional and renewable generating plants shall be done separately – may not help in improving merit order or bringing down costs and improving efficiencies. Further, the most important requirement of competitive bidding will be bypassed and cripple distribution companies.

In case an existing beneficiary of firm power from a generating plant which completed useful life, do not opt for RE power to be installed by the same developer in the same location, the existing beneficiary is loosing the benefit of getting cheaper power (at O & M plus fuel cost). The RPO obligation might have already been fulfilled by him though procurement from different and may be cheaper sources. The linking of RPO obligation / sourcing of RE power from the particular developer may distort merit order procurement as well as may result in excess procurement also by the discom. Such a step of bundling a cheaper power plant (which has completed useful life and supplying power at variable cost) with also cheaper RE power (now a days the price discovery indicates RE power is as competitive as thermal power) will result in backing down of very cheap conventional generation in case of high RE generation at the same location to maintain the schedule which is a distortion of merit order. In the bundled power plant, the conventional part is regulated and option to get RE power part from competitive bidding is eliminated as both parts have to be regulated. The developer will try to get reduced tariff by bundling cheaper conventional plants with new RE power plants without prudent cost mechanism through cost subsidization. Efficiency improvements are thus not achieved. This provision is helping Government owned generating companies to enter into RE power domain by a backdoor entry eliminating competition and avoiding participation in competitive bidding. Once again private sector participation in RE power will be jeopardized and reduced volume available in RE will lead to discovery of higher prices in competitive bidding. Some power plants in the private sector (e.g. Dahanu Power Plant) or IPPs with long term PPAs are completing their useful life in a short while and it is discriminatory if they are not allowed similar arrangement to bundle these plants with RE power and provide similar offers by bypassing competitive bidding. This provision is clearly seen by market participants to provide backdoor entry to some Government companies into RE pie thorough regulated route at a time when competitive bidding is giving progressively reduced price discovery in the recent years. At present, the advantage given to Government companies in conventional generation vis-à-vis private companies in conventional generation has large disparity in regulated price vis-à-vis price discovered through competitive bidding led to unviability of private sector IPPs leading to NPAs in private sector and also costly power procurement by distribution companies from the recent and upcoming projects from the government owned companies whose tariff is regulated. Even though regulatory commissions emphasize that they were adopting cost plus tariff with benchmarking, the regulated tariffs are much higher and not benchmarked against price discovered through competitive bidding. This led to non-viability of distribution companies also. The viability of power sector depends upon viability of distribution companies. Low retail tariffs, and supplying power to agricultural consumers and domestic consumers (including BPL category) at low tariff requires power procurement at low cost from generating companies which is possible only through competitive bidding and completely eliminating regulated tariffs to Government owned generating companies. **Hence, all new power procurement has to be through competitive bidding without which the retail prices cannot be reduced.** While non-tariff income of distribution companies is passed on to consumers to reduce the tariff, the same is not done in case of Government owned generation and transmission companies especially at the central level. If the non-tariff income from Government owned generation / transmission companies is passed on to the distribution companies, the present low retail tariff and subsidies can be viable. **For making distribution companies viable, two important steps need to be taken immediately 1) all power procurement though only competitive bidding and Government owned generation and transmission companies should come though only competitive bidding and those projects which are regulated presently should lower the tariff (by reducing ROE, passing of non-tariff income etc.) be benchmarked with prices discovered in competitive bidding.**

8.2

Section 8.2 from the consultation paper is reproduced below,

"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.

Competitive bidding is ensuring that power is procured for long / medium / short term with least cost option. During dispatch also, merit order requisition from various sources of contracted power is being done by the distribution companies. At DNHPDCL, optimization of power procurement is done with setting the objective function as minimization of total bill for the day using fixed cost, variable cost, incentive / penalty, pay / take implications etc. by modeling each and every PPA from which scheduling is done. Multiple optimization algorithms are available through GAMS (Generalized Arithmetic Modeling System) software which require customization to model the PPA terms and conditions. Discoms should have appropriate software toola to enable merit order procurement. Under decentralized dispatch, SLDC need not have to schedule generation under merit order dispatch mechanism. SLDC should only ensure that day-ahead balancing is done. Discom anyway will be ensuring merit order procurement by going for procurement all power (long term / medium term / short term) through competitive bidding mechanism or PX. The power procurement from regulated power plants / sources should henceforth be discontinued.

8.3 & 8.4

These clauses may be deleted and URS power on day-ahead basis on weekly / monthly / annual basis can be dealt through the mechanism suggested in the consultation paper under Clause 10.3(a) and 10.3(b).

9

In the case of privately owned generating station with part of the capacity covered under Section 63 (Competitive Bidding), part of the capacity under merchant power and a part of capacity sold to a distribution company through regulated tariff, the regulated tariff should not be determined considering the entire plant and then deducing for the part of the plant. It is better to benchmark the capital cost of the entire plant based on the competitive bidding price as the ceiling and then the tariff for the regulated part to be determined and regulated tariff should be lower than the price discovered through competitive bidding if Government allocates captive coal mine (25 years PPA with Discom). If the prices discovered through competitive bidding is through a bid for low volume, then such price may not be reasonable and such price can be used as only a ceiling price. The regulated tariff can be higher than price discovered through competitive bidding only in case of government promoting a particular technology / fuel or development of a particular area etc. In case of a portion of power offered to the home state by the IPP, such power in any case would be cheaper than the price discovered through competitive bidding.

10.3 (a) and 10.3(b)

These provisions are essential in the present context of surplus power. The URS power on day-ahead basis even could be considered under this method.

10.4, 10.5(a), 10.5(b)

The existing hydro & pumped storage plants (PSP) already built, have beneficiaries and these beneficiaries can use flexible generation for balancing RE generation as well as for peaking power as per then discretion. New Hydro / PSP project can be built for the sole purpose of supplying reserve power / balancing power can be considered under Ancillary Services (AS) and the administration (scheduling), real-time dispatch etc.) of the AS shall be under NLDC / RLDCs.

10.6 Gas / RLNG / Liquid Fuel plants

Similar to the hydro / PSP plants as above.

New capacities to be built can be used under Ancillary Services. Further, the Discom should be permitted to surrender the capacities (in case of costly fuel like RLNG / Liquid fuel / non-APM gases) allocated to them by GoI or procured by them from IPPs and the central commission can consider recovery of the tariff under Ancillary Services only. This mechanism would help in complementing with cheaper RE power not only in balancing but also in cost optimization. The commission may also consider Hybrid Regulated Virtual Power (HRVP) plants with components of RE, Energy Storage, and costly non-APM Gas / RLNG / Liquid fuel based plants for balancing as well as to match ramp up / ramp down requirements. Such HRPV may be a better option to save stranded assets under costly non-APM / RLNG rather than considering bundled RE and coal generations as proposed in Section 34. Under HRVP, RE and hybrid RE components as well as energy storage plants shall be procured only through competitive bidding. While regulated part shall be only for stranded capacity included from non-APM / RLNG / Liquid fuel based generation surrendered by Discoms and such generation shall either replace energy storage or shall be used as an Ancillary Service. Only AS part shall be despatched by NLDC / RLDCs. These components need not be co-located and combining these components through regulatory approval is only for the purpose of reducing the tariff and also to book the tariff under reliability requirements.

11

As suggested in 11.4 and as envisaged in the tariff policy 2016, appropriate commission shall have to evolve benchmark capital cost as reference to allow reasonable capital cost to generators or transmission licensees. Such benchmark capital cost has to be based on the price discovered through competitive bidding projects. Benchmarking of individual component costs should not be done whereas benchmarking the cost based on overall tariff is recommended. In case of existing plants, or plants whose investment approval is already done, additional capitalization beyond CoD shall be permitted in case of through suggested in Section 11.6 (iii) only. The purpose of Hon'ble Commission allowing additional 0.5% RoE is to ensure completion of projects on time. Hence, any expenditure related to IEDC and IDC for delays should not be admitted. Only those works related to environmental norms, PAT scheme can be permitted beyond CoD and up to cut-off date without penalizing on 0.5% RoE. As suggested in 11.6 (iv), O&M allowance shall be reduced to the extent of works done under special allowance granted by the Commission. Expenditure under 11.6 (v) shall be approved after prudent check. All expenditure of the regulated plants shall be approved subject to third party independent audit. However, 11.7 is OK.

11.8

Benchmarking of capital cost is a complex mechanism due to different technologies / fuel involved and subjectivity in investment approvals. Hence, all procurements shall be through competitive bidding only and regulated tariff only in case of the projects in difficult / notified areas such as J&K, naxal affected areas and hydro projects in difficult terrains, new technologies promoted by Government etc.

Benchmarking of capital cost shall be only on the basis of prices discovered by competitive bidding. Looking at the way prices reduced over the years, in the telecom sector, competitive bidding ensures value additions in the initial period of evolving technologies and in the later years reduced costs to the consumers. Similar development took place in the logistic sector where customized services, efficient and faster services emerged in the initial years and cheaper and competitive services in the later years. In the transportation sector, the taxi fares are regulated by the RTO which were pinching the consumers. When the competition came, the fares drastically reduced with OLA / UBER etc. and the consumer is immensely benefitted. Even in power generation, competitive prices are discovered with the advent of IPPs. Private generation is much cheaper if procured through competitive bidding while regulated private generation, for instance Mumbai is much costlier. The regulated publicly owned generation even with captive coal

blocks is much costlier compared to IPP generation. If the Discoms have to be viable, all procurements have to be through competitive bidding process.

12

The options of extending useful life of generating plants / transmission lines either through renovation and modernization or through special allowance will lead to reduced cost to the consumer. However, in the case of capital cost to be incurred under the R&M option is based on RLA (Residual Life Assessment) and project report which has to be *examined through third party audit* which would change the capital base. Reassessment of life shall be done at the beginning of every tariff period and provision for additional capital expenditure through a provision as prescribed in Ind AS and corresponding treatment of depreciation thereof. In case of special allowance allowed to generating plants after 10^{th} year of operation, the benefits to be shared with beneficiaries have to be quantified.

16 & 17

Since debt is becoming cheaper with present regime of low interest rate along with low inflation and high liquidity, debt component can be increased to 80% of capital cost (instead of 70%). This would reduce overall tariff and benefit consumers. Developers should be encouraged to raise debt from international sources (FII) as low cost debt available from FII / IFC etc.

18

In case of delay in commissioning (as per the targets set by Commission), there can be disincentive in RoE. Only those works related to environmental norms, PAT scheme can be permitted beyond CoD and up to cut-off date without penalizing on 0.5% RoE. Further, penalty of 1% of RoE can be imposed in case of delay in commissioning of FGMO / RGMO, communication system etc. High RoE presently is due to many regulated projects. Once most of the projects come through competitive bidding, market forces are likely to exert downward pressure on the IRR of the new projects.

20.3

IWC is presently normative and based on several components out of which O&M expenses is a major part and O&M expenses when treated as a % of capital cost (hydro plants) may lead to higher IWC (especially for delayed hydro projects due to IDC and IEDC). Cost of maintenance spares is a component of IWC and expressed as a % of O&M cost (For example, for hydro 15% of O&M, for thermal 20% of O&M etc.) which will increase IWC in case of projects with high O&M cost. It is worthwhile to delink cost of maintenance spares from IWC.

21.2

O&M expenses of hydro station is given as a % of a capital cost which includes IDC and IEDC. Thus delayed projects will get benefit of higher O&M charges. The anomaly should be corrected.

Further, overlapping of O&M expanses and compensation allowance (thermal) may lead to higher tariff as some of the works under compensation allowance may lead to lower O&M expenses and discount for the same is not accounted in O&M expenses.

21.7

Some of the plants viz., peakers and plants with very less schedule may have less operating hours and consequently reduced O&M cost. Such differentiation has to be made based on the operating hours. Treatment of income from other businesses have to be accounted prudently to reduce the O&M expenses. O&M expenses incurred in the regulated business may also help other business areas of the company such as common facilities, manpower etc.

23. Blending of Imported Coal

Some of the regulated generators using domestic coal will resort to purchase of high cost e-auction coal or blending with imported coal (% of blending varies and not known to Discoms apriori). In case designated fuel is domestic coal, the generating stations may have to restrict generation to the extent of available coal from the designated source. In case of alternative arrangements such as e-auction coal, blending with imported coal, variable cost shoots up and burdens the generators with high cost generation. Further, since the variable cost is not known at the time of scheduling, Discom suffers from inability to schedule in a merit order way. When the variable cost is known post facto, the cost of generation is even higher than generation from those plants with 100% imported coal (total tariff of imported coal based Mundra UMPP is 2.40 Rs. / KWH while that of Mauda-I is 4.80 Rs./KWH). The regulated power plants are having long term PPAs and captive coal mines or linkages with CIL despite which the tariffs are higher. **Hence, blending shall be avoided unless there is heavy demand for power in the present surplus scenario. In case blending is required, % of blending, costs, etc. shall be decided 1 month in advance in the OCCM of the region so that merit order scheduling will not suffer. Allowing pass through of fuel is not recommend at all.**

27

Incentive mechanism for transmission system (AC and HVDC) has to be reviewed based on the data collected from transmission owned by various state system. In many states AC transmission availability generally exceeds 99% and hence incentive should be for NATAF > 99%. Inter-regional lines and those lines subject to congestion / high loading conditions (based on the advice of NLDC / RLDC) shall have separate availability norms with higher incentive to ensure day-ahead market function without congestion. Similarly, back-to-back HVDC links shall also have higher NATAF.

Different incentives may be provided for generators during peak and off-peak hours. All generators whose PLF is equal to or more than availability factor shall only be eligible for incentive. There must be disincentives also along with incentive for all generators. A scheme for disincentive mechanism shall also be worked out.

31
At present, generating and transmission companies owned by central government are having other streams of income such as consultancy services etc. using the same infrastructure and manpower. Such non-tariff income should be passed-on to the beneficiaries. This is especially important as Discoms are struggling for their survival.

It is seen that, funds from PSDF are not used to help the Discoms, instead the funds are being used elsewhere (e.g., generators and railways) for indirect support.

34. Renewable Generation by existing Thermal Generation Stations

In case an existing beneficiary of firm power from a generating plant which completed useful life, do not opt for RE power to be installed by the same developer in the same location, the existing beneficiary is losing the benefit of getting cheaper power (at O & M plus fuel cost). The RPO obligation might have already been fulfilled by him though procurement from different and may be cheaper sources. The linking of RPO obligation / sourcing of RE power from the particular developer may distort merit order procurement as well as may result in excess procurement also by the discom.

Such a step of bundling a cheaper power plant (which has completed useful life and supplying power at variable cost) with also cheaper RE power (now a days the price discovery indicates RE power is as competitive as thermal power) will result in backing down of very cheap conventional generation in case of high RE generation at the same location to maintain the schedule which is a distortion of merit order.

In the bundled power plant, the conventional part is regulated and option to get RE power part from competitive bidding is eliminated as both parts have to be regulated. The developer will try to get reduced tariff by bundling cheaper conventional plants with new RE power plants without prudent cost mechanism through cost subsidization. Efficiency improvements are thus not achieved. This provision is helping Government owned generating companies to enter into RE power domain by a backdoor entry eliminating competition and avoiding participation in competitive bidding. Once again private sector participation in RE power will be jeopardized and reduced volume available in RE will lead to discovery of higher prices in competitive bidding. Some power plants in the private sector (e.g. Dahanu Power Plant) or IPPs with long term PPAs are completing their useful life in a short while and it is discriminatory if they are not allowed similar arrangement to bundle these plants with RE power and provide similar offers by bypassing competitive bidding. This provision is clearly seen by market participants to provide backdoor entry to some Government companies into RE pie thorough regulated route at a time when competitive bidding is giving progressively reduced price discovery in the recent years.

At present, the advantage given to Government companies in conventional generation vis-à-vis private companies in conventional generation has large disparity in regulated price vis-à-vis price discovered through competitive bidding. This led to unviability of private sector IPPs leading to NPAs in private sector and also costly power procurement by distribution companies from the recent and upcoming projects from the government owned companies whose tariff is regulated. Even though regulatory commissions emphasize that they were adopting cost plus tariff with benchmarking, the regulated tariffs are much higher and not benchmarked against price discovered through competitive bidding. This led to non-viability of distribution companies also.

The viability of power sector depends upon viability of distribution companies. Low retail tariffs, and supplying power to agricultural consumers and domestic consumers (including BPL category) at low tariff requires power procurement at low cost from generating companies which is possible only through competitive bidding and completely eliminating regulated tariffs to Government owned generating companies. Hence, all new power procurement has to be through competitive bidding without which the retail prices cannot be reduced. While non-tariff income of distribution companies is passed on to consumers to reduce the tariff, the same is not done in case of Government owned generation and transmission companies especially at the central level. If the non-tariff income from Government owned generation / transmission companies is passed on to the distribution companies, the present low retail tariff and subsidies can be viable. **For making distribution companies viable, two important steps need to be taken immediately 1) all power procurement though only competitive bidding and Government owned generation and transmission companies should come though only competitive bidding and those projects which are regulated presently should lower the tariff (by reducing ROE, passing of non-tariff income etc.) be benchmarked with prices discovered in competitive bidding.**

36 Energy Storage

Energy storage options at transmission level and generation level have to be procured only through competitive bidding.

37.5 Delay in CoD

In case of delay in CoD, IDC and IEDC may impact total project cost adversely. Therefore, benchmarking capital cost with tariff discovered through competitive bidding and penalties for delays in project implementation may have to be introduced.

37.21

Peak period for each power plant may vary based on the planned and forced maintenance of the units in the power station and also other stations. For each power station, peak period has to be defined in the LGBR prepared by RPCs.

38

The pass thru provision has to be removed. ***The Govt. owned companies and IPPs supplying 100% power to DISCOMs to through long terms PPAs were being allotted dedicated coal blocks, which will ensure availability of fuel and at reduced cost. With this arrangement, pass thru clause is not required.*** Two ways of determining the fuel cost may be evaluated. The commission may fix up normative cost by studying the past data and the cost of fuel should in any case be at least 50% cheaper due to reduction in overheads of CIL (Coal India Ltd.) and cost of rail transportation. Coal washaries can also be setup at the mine head. The second way of determining the cost of fuel is the cost plus approach with benchmarking. The fuel prices of coal (60% of the generation for the country coming from coal) affects the power tariff in significant way and thereby the procurement cost of the DISCOM adversely. It is advisable to have a common regulator for coal and power to sort out unilateral price raise by the coal companies. Till then it is preferable to have a common ministry for department of coal and department of power.

Allotment of coal blocks would result in low fuel price and high availability of fuel which may help in avoiding generation loss due to coal supply issues and cheaper fuel with better GCV (Gross Calorific Value) and loss of GCV before firing will be minimum. Hence, pass through clause can be removed.

Further, the generating company may procure fuel at high cost in case non-availability from the designated source or may use the blending with imported coal which may increase the fuel cost i.e., energy charges, thus impacting merit order procurement and merit order scheduling which are based on fuel cost / variable cost. At present, the available generation in the country is much higher that the demand and in most cases the distribution companies may not require additional generation from fuel purchase through e-auction or imported coal or higher level of blending. Therefore, the generating company should offer DC (Declared Capability) with designated fuel and additional DC with e-auction fuel and additional DC with likely blending ratio through imported coal. Thus, the choice lies with discoms to choose only DC with designated fuel or declared capabilities with other variates. There must be total choice in scheduling. There must be two levels of permissions to be obtained from beneficiaries / discoms – weekly permission for procurement through e-auction and blending through imported coal; day-ahead permission through requisition against various DCs offered, both options should be followed. An indicative price for each DC should be given to enable merit order requisition by the Discom. At present discoms are making huge losses as sources of power and price for various fuel wise DCs are not made available before the fact and sudden surprises seen after the fact when the monthly bills are presented. Such kind of authoritative hegemony by the generating companies should be prevented as discoms are helpless due to sole responsibility of providing 24x7 power supply rests with discoms.