RECOMMENDATIONS REGARDING IMPLEMENTATION OF AVAILABILITY BASED TARIFF (A.B.T.) IN INTRA-STATE SYSTEMS

1. Availability Based Tariff (ABT), with a unique Unscheduled Interchange (UI) component, was recommended for Central Sector generation and private generation by M/s ECC, USA after a nation-wide, World Bank/ADB-sponsored study in 1993-94. Govt. of India then agreed to its early implementation, as a covenant of World Bank/ADB loans to Power Grid Corporation of India. After constitution of the Central Electricity Regulatory Commission (CERC) in 1998, the matter came under the purview of CERC, which after due process in 1999 has issued its orders and regulations on this subject starting from January 2000. ABT has since been implemented at inter-State level (i.e. for Central generating stations), region-by-region during 2002 and 2003.

2. Following improvements have been brought about in operation of regional grids by ABT:

   (i) Grid frequency has dramatically improved from 48-52 Hz range to 49.0-50.5Hz range for most of the time.
   (ii) A higher consumer demand is being met, due to built-in incentives to maximise generation in peak-load hours.
   (iii) Generating stations are being operated according to real merit-order, on region-wide basis, through decentralized scheduling.
   (iv) Hydro-electric generation is being harnessed more optimally than done previously.
   (v) States' share in Central generating stations have acquired a new meaning and grid discipline is encouraged.
   (vi) Open access, wheeling of captive generation and power trading have been enabled by placing in position the mechanism (UI) for handling deviations/mismatches.

(vii) States meet their occasional excess demand by over-drawing from the regional grid and paying applicable UI charges to the under-drawing States.

3. The intra-State generating stations are not yet on ABT, due to which opportunities for further optimisation are being lost. For example, the intra-State stations (other than those owned by the still-bundled SEB) have no incentive presently to maximise their generation in peak-load hours and to back down during off-peak hours. They are also not induced to respond to grid contingencies. Scheduling disputes between generating stations and State LDCs could arise, particularly in case of IPPs. With the present focus on commercial aspects, it is very desirable that ABT is applied to all intra-State stations (except those embedded in vertically bundled licensees' systems) as well, whether SEB-owned or otherwise, for optimised utilisation of intra-State resources.

4. Optimum utilisation of pumped storage capacity is another area of concern. The 4x100 MW Kadamparai scheme belonging to TNEB has been fully utilised since introduction of ABT in Southern Region. Water is pumped up in off-peak hours when UI rate is low, and power is generated during peak-load hours when UI rate is high. On the other hand, in the absence of intra-State ABT/UI in Maharashtra, a similar commercial signal is not available to Tata Power, and their 150 MW Bhira pumped storage scheme is still not being utilised optimally. Srisailam pumped storage scheme in Andhra Pradesh too has not received due priority, as APGenco has no UI.

5. The foregoing has been duly appreciated by the Central Government and the following has been stipulated in the National Electricity Policy notified on 12.2.2005:

"5.7.1(b) The ABT regime introduced by CERC at the national level has had a positive impact. It has also enabled a credible settlement mechanism for intra-day power transfers from licensees with surpluses to licensees experiencing deficits. SERCs are advised to introduce the ABT regime at the State level within one year."

6. As and when an SEB is unbundled and the State's distribution system is divided into zones, it would be essential that each zone has a schedule for power that it is to receive through the State grid. The intra-State system would then look very much like the present regional system : a number of generating stations supplying power through a transmission grid to a number of beneficiaries, with scheduling, metering and energy accounting carried out by a load dispatch centre. It would only be logical to replicate the regional system (of shares/allocations, scheduling, metering, UI, etc), which is already tried and proven.

7. The UI liability of a State, after unbundling, would depend on judicious scheduling for the intra-State entities and their dynamic response. This can all be centralised at the State LDC adopting a disciplinarian approach, but it has the risk of being resisted and flouted. Highly reliable communication, SCADA, AGC etc would also be required, with associated cost and complications. A more pragmatic approach, therefore, would be to delegate the responsibilities to the intra-State entities for decentralised action, with UI mechanism providing the required frame work for keeping all entities on track. In other words, it would be desirable to apply UI on all intra-State entities which are supposed to have a schedule.

8. While for a total compatibility with the system presently operating at the inter-State (regional) level, it would be desirable to adopt the same system in-toto for intra-State entities, it is recognized that there could be valid reasons, State-specific, to deviate from the regional mechanism. It is recommended that the concerned SERCs examine the following issues in detail, in association with the respective SEB/STU and pragmatically decide their approach.

9. <u>Structure and components of ABT</u>

The present ABT for Central generating stations comprises of three (3) components : capacity charge, energy charge and UI. This structure is rational and appropriate for the conditions prevailing in India, and should straight-away be adopted for all intra-State generating stations. However, incentive may be linked to plant availability, instead of linking to PLF (as is presently done for Central Stations). Linking of incentive to PLF effectively converts the incentive into a supplementary energy charge, and distorts the merit order. Most Central stations being pit-head (and, therefore, not being required to back down during off-peak hours), do not face a major problem on this account. On the other hand, many intra-State generating stations would be at load-centres and/or will be liquid fuel-based. They would have a high variable cost, would often be scheduled to back down during off-peak hours, and would, therefore, have a lower PLF. Linking of incentive to PLF in their case would be counter-productive and it would only be logical to link the incentive to plant availability. Para 144 and 145 of CERC order dated 29.3.2004 in petition no. 67/2003 may also be seen in this connection (copy enclosed).

Certain issues have come up recently in ABT for Hydro stations, particularly in NER. It is suggested that SERCs may exercise caution while extending ABT to intra-State Hydro stations, or wait for resolution of these issues by CERC (for Central stations).

10 <u>Norms and parameters for tariff:</u>

Various norms and parameters in the present ABT for Central generating stations have been fixed by CERC primarily considering the past performance of NTPC and NHPC plants. It is possible that the performance level of the intra-State power plants, due to a variety of factors, may not match those of NTPC and NHPC. In such cases, it would be appropriate to adopt different norms and parameters, atleast for a transition period. CEA have also prescribed certain norms recently, and these too may be considered by SERCs.

11. <u>Treatment of secondary oil consumption</u>

It has been a practice so far in India to treat secondary oil consumption as a component of energy charge. However, secondary oil is consumed only when a coal/lignite-fired unit has to back down below about 60% or has to be started up/shut down. During normal operation, secondary oil should not have to be fired at all. In other words, during normal operation (above 70% load), the variable cost of a generating unit would comprise of only the coal cost. In order to get the energy charge to reflect the unit's correct variable cost (and thereby to give the unit a better merit-order position), it would be desirable to treat secondary oil consumption as a component of plant's fixed cost, and recover it through capacity charge instead of energy charge. This is particularly important for load-centre stations which would be required to back-down during off-peak hours due to their comparatively higher variable cost, and may be considered by SERCs at an appropriate stage.

12. <u>Relationship between capacity charge and plant availability</u>

It has been suggested in para 9 above that the incentive may be linked to plant availability. Once this is done, incentive can as well be merged with capacity charge. The relationship between capacity charge payment for the year and average plant availability can then have three possible shapes, as shown in figure-I. It is our majority view that shape (c) is more equitable than the others.

13. <u>Time block for UI</u>

In the inter-State ABT, UI is determined for each 15-minute time block. This inherently requires 15-minute wise energy metering on all interchange points of each regional constituent. Similar special energy meters shall be required for all intra-State constituents if the same 15-minute time block is to be applied intra-State. As some States already have meters for 30-minute time-block, a question has been raised as to whether the intra-State time block can be of 30 minutes.

The primary idea of UI is to price the deviations from schedules according to prevailing (i.e., real time) system conditions. The time block should, therefore, be as small as practicable, and a 5-minute time block would be still better, theoretically. 15-minute has been a satisfactory compromise, as regional grid operation over the last 2-3 years has shown. As such, we recommend that all States adopt a time block of 15 minutes only, which would also enable direct back-to-back accounting with regional UI. However, implementation of intra-State UI should not get delayed on this account alone. It is, therefore, suggested that following procedure may be adopted as an interim arrangement for determination of UI charges for those intra-State entities who are having 30 - minute meters on their periphery.

Energy actually drawn in a 30 - minute block	=	A
Scheduled energy for that block	=	B
UI energy for the 30 - minute block	=	(A-B)
Average frequency (regional) for first 15 minutes	=	C
Average frequency (regional) for second 15 minutes	=	D
UI rate corresponding to C	=	E
UI rate corresponding to D	=	F

UI charge for the intra-State entity, for the 30 - minutes block =(A-B)x (E+F)/2.

14. Maximum and minimum UI rates

The minimum UI rate at regional level is zero, corresponding to the variable cost of overflowing hydro-electric stations. The same should be adopted for intra-State system as well, whether a State has intra-State hydro stations or not. (A detailed explanation of interplay between UI rate and system marginal cost is given in "ABC of ABT - a Primer on Availability Tariff" written by Shri Bhanu Bhushan).

Similarly, the maximum intra-State UI rate should basically be same as the ceiling regional UI rate, to enable back-to-back operation of regional and State UI pool accounts. For example, suppose a DISCOM overdraws by 10 MW from State grid, due to which the State overdraws 10 MW from the regional grid, while frequency is 49.0 Hz. The State shall have to pay to regional UI pool account for the overdrawal at the ceiling rate, which is Rs. 5.70 per kWh presently. This amount should in turn be paid by the defaulting DISCOM into the State UI pool account. UI rate for the DISCOM should also, therefore, be Rs. 5.70 per kWh.

The present regional ceiling UI rate was specified by CERC when diesel price was about Rs. 22 per litre. Now that the diesel price is around Rs. 32 per litre, it may be necessary to increase the ceiling UI rate. This matter is, however, in CERC's jurisdiction, and it is being mentioned here only to apprise SERCs about the possibility of such an increase so that necessary provision is kept in the concerned intra-State regulations.

15. Threshold frequencies for UI rate

In the present relationship between frequency and regional UI rate specified by CERC, the minimum UI rate (zero) is reached at 50.5Hz and the maximum (ceiling) UI rate is reached at 49.0Hz. The experience with such frequency thresholds has generally been satisfactory. In any case, the intra-State UI has to necessarily have the same frequency threshold as regional UI, for back-to-back operation of regional and State UI pool accounts.

16. <u>Adjustment for intra-State transmission losses</u>

In para 14 above, it is assumed that transmission losses in intra-State grid are not affected by the deviations from schedules (UI) of the intra-State entities. While this simplifying assumption could be adopted to begin with, the impact of intra-State UI on transmission losses would have to be taken into account when one starts getting into the details. For example, 10 MW overdrawal by a DISCOM may cause (depending on topology and power flow scenario) an increase in intra-State transmission loss by 0.3 MW. Consequently, the resulting overdrawal of the State from regional grid would be 10.3 MW, and the full coverage of State's UI liability would require that the UI rate applied to the DISCOM be 3% higher than the regional UI rate.

The incremental transmission loss would, however, change with power flow pattern, requiring detailed studies/computations and may still be very subjective. It is, therefore, recommended that this particular aspect be deferred for some time, and for the present, intra-State UI rate relationship with frequency be kept same as that at the regional level.

17. <u>Entities to be covered in ABT</u>

In the first instance, intra-State ABT should be implemented for

i) all SEB/STU-owned generating stations above 10 MW
ii) all State Government-owned/State generating company- owned generating stations above 10 MW
iii) all IPPs, i.e. private/JV-owned and any other power stations above 10 MW, which are contracted to supply power to SEB/STU/State Govt/DISCOMs

iv) all DISCOMs, as and when SEBs are unbundled, and entities like NDMC, BEST.

v) distribution licensees who are supplied power from identified generating stations as per an allocation.

18. <u>UI (not the full ABT) could be implemented for</u>

i) all entities availing “Open Access”

ii) all parties availing wheeling of captive generation

iii) all generating stations below 10 MW, (as a general guideline), which are connected to the State/DISCOM grid, including non-conventional

iv) Merchant power plants, pumped-storage plants,

v) all entities/consumers with captive/co-generation, particularly those with a possibility of feeding power back into the grid

vi) licensees with own generation, e.g. TPC, BSES, AEC, CESC.

It is not desirable to implement ABT separately for the power plants of licensees, as long as the concerned licensee (such as TPC and BSES in Mumbai) continues as a vertically integrated utility. Covering the licensee under the UI mechanism (operating on its periphery) would suffice for inducing merit-order operation of embedded generation.

19. For implementation of ABT and UI mechanism within a State, the activity on the critical path would be installation of special energy meters on the periphery of all entities which are to be covered by ABT and UI. It is recommended that the meters already field-proven, and fully conforming to the specification used in case of Gujarat be ordered by the respective SEB/STU on priority. Other preparatory action can follow.

20. In conformity with section 166(4) of the Electricity Act, 2003, the SERCs may request the respective State Governments to constitute a Coordination Forum at the State level, which may also oversee the implementation of intra-State A.B.T., if so decided.

21. <u>Implications of not implementing A.B.T. for Intra-State Stations</u>

As mentioned earlier, the A.B.T. as implemented for Central generating stations comprises of three components : (a) Capacity charge, (b) Energy charge, and (c) UI. Payment of capacity charge for reimbursement of the annual fixed cost is linked to average plant availability achieved over the year, which induces the plant owner to maximise its availability, without encouraging over-generation during off-peak hours. A power plant not on A.B.T. would either have a single-part tariff (i.e. a constant paise/kWh rate), or a two-part tariff (e.g. K.P. Rao formula). In case of single-part tariff, with a composite paise/kWh rate combining fixed and variable costs, the plant owner would have a perpetual incentive to maximise the generation, even during off-peak hours when his plant should in fact be backing down depending on its position in variable cost-based merit order. He would resist if the SLDC gives him a schedule with backing down in off-peak hours, and three possibilities would arise, as follows:

(a) SLDC issues a schedule with backing down by this station during off-peak hours, and the station generates energy according to the given schedule: The Station owner would suffer a revenue loss on account of energy not generated.

(b) SLDC issues a schedule with backing down by this station during off-peak hours, but the station does not back down: The station will earn extra profit, while the State would under-draw from the regional grid, and in the process suffer a loss (paying a higher rate to the station for the extra energy, and getting paid a lower rate for the same energy quantum from regional UI account).

(c) SLDC is forced by the station owner to give full schedule for the station (ignoring merit-order), and consequently requisitions only a part of State's entitlement in Central stations during off-peak hours; The State would again suffer a loss, and SLDC could be blamed for scheduling costlier energy while forgoing cheaper energy from Central stations.

The result of the above would be a perpetual tussle between the SLDC and the generating station, and the ultimate result would be a loss for the State as a whole, one way or the other. The situation would somewhat improve in case the station is on K.P. Rao tariff (in which full fixed charges are paid even in case of backing down). However, the experience between 1992 and 2002 clearly shows that K.P. Rao tariff did not address all the problems and indisciplined behaviour by utilities could not be curbed. In particular, there was nothing to discourage SEBs from overdrawing during peak-load hours and underdrawing during off-peak hours. There were perpetual commercial disputes as well. While most of the problems at the inter-State level have been addressed by implementation of A.B.T. for Central stations, similar problems would arise between intra-State entities if sufficient care is not taken while unbundling the SEBs. Specifically, the intra-State mechanism must have features which (a) encourage generation maximisation during peak-load hours, (b) encourage backing down of generation as per merit order during off-peak hours, (c) discourage DISCOMs from over-drawing during peak-load hours.

A.B.T. would directly provide all these. If an SERC proposes to adopt a variant, it would have to see how the above features are incorporated in the proposed mechanism.

22. Implications of Adopting a Balancing Mechanism different from Regional UI

Some States are contemplating balancing mechanisms differing from the concept of frequency-linked U.I. rate. The implications are explained below through an example.

Suppose two States A and B have a thermal station each, both having a variable cost of 150 paise/kWh. Suppose both have been scheduled to generate at 90% of their available capability during off-peak hours on a certain day. Also suppose that State-A has adopted UI mechanism totally identical to the regional UI mechanism, but State-B has adopted a different balancing mechanism concept in which the price of balancing power, instead of being a function of frequency, is calculated by the SLDC from time to time. Suppose it is 210 paise/kWh at a certain time, while frequency is 49.9 Hz and corresponding regional UI rate is 180 p/kWh. In State-A, the thermal station would see the frequency and ramp up its generation from 90% to 100% of available capability (say 500 MW), at an incremental expenditure of 150 paise/kWh. The 50 MW over-generation would result in 50 MW of underdrawal by State-A, for which it would receive UI charges @ 180 paise/kWh from regional UI pool account, which would get passed on to the thermal station. There would thus be a saving of 30 paise/kWh on 50 MW for the thermal station of State-A, which would work out to Rs.15000 per hour. Other utilities in State-A would not have any financial impact on the above account.

The situation in State-B would be more complex. The thermal station may want to increase its generation, since it would get 210 paise/kWh against an incremental fuel expenditure of 150 paise/kWh. But this would result in a loss for State-B DISCOMs; they would pay 210 paise/kWh to the thermal station for its extra generation, but would receive only 180 paise/kWh from regional UI pool account for the resulting underdrawal. Due to this anomaly, the SLDC of State-B may not permit the thermal station to increase its generation beyond the given schedule (90%), and the State as a whole would miss an opportunity for some financial gain. In other words, generally speaking, State-B may not gain anything by adopting a balancing mechanism differing from regional UI.

There would be another issue to resolve. If a DISCOM in State-B overdraws, it would pay 210 paise/kWh into the State UI pool account for the energy overdrawn. The State would have to pay only 180 paise/kWh to the regional UI pool account for the consequent overdrawal from regional grid. What is to be done with the 30 paise/kWh differential ? And it could be negative as well ! These complications also can be avoided by extending the regional frequency-linked UI rate to all intra-State entities on back-to-back basis.

23. Revenue Balancing between DISCOMs

Because of differing consumer mix, different DISCOMs in a State may have differing daily load curve, differing average consumer tariff and differing realisation percentage. If power is supplied to all DISCOMs at identical rates (as would normally be the case immediately after SEB unbundling), it could mean widely differing amounts for meeting their own expense. Some DISCOMs may have much bigger gaps than others (it being unlikely that any DISCOM would be able to meet all its obligations on its own). This situation may be further aggravated if DISCOMs have to as well pay UI charges on back-to-back basis, as has been recommended.

However, it needs being appreciated that revenue balancing between DISCOMs is necessary, whether UI charges apply on them or not. The prudent approach would be to treat all DISCOMs similarly, in respect of generation allocation, power supply tariff, UI charges, etc., to ensure that similar incentives apply for all. In particular, UI mechanism should not be distorted in any manner. Only then would each DISCOM be properly incentivised to take due care in its load forecasting, daily requisitioning, load management planning and load curtailment if grid situation so requires. All revenue balancing between DISCOMs may be achieved through diversion of Government subsidy to the DISCOMs which are relatively more negative.

Allocation of intra-State generating station capacity between DISCOMs, as also allocation of the States' entitlement in Central stations between DISCOMs, have to be done very judiciously. These should be on 24-hour basis only. In case it is found that a DISCOM has a surplus in peak-load hours as well, some of its allocation should be diverted to the needy DISCOMs, but only on a permanent, 24-hour basis, and by the authority which is responsible for original allocation.

However, no restrictions should be imposed on DISCOMs regarding trading of any off-peak or occasional surplus, either on bilaterally contracted basis or as UI. Only in case of an allegation of sale of power by a DISCOM to earn money while its own consumers are being load-shed, should be SERC/ State Government look into the matter. At times of low frequency, a DISCOM may be justified in not supplying power to non-paying consumers, either to curtail its overdrawal (and UI liability) or to improve its finances (by earning some UI). SERCs could specify frequency thresholds for different consumer categories, above which they should not be shed.

24. Captive/Co-generation and non-conventional sources

A.B.T. is basically meant for large power plants whose capacity is assigned to one or more beneficiaries on a 24 - hour, long-term basis. It presumes that the plant operator is able to declare the plant availability on day-ahead basis, and is then able to supply power as per the schedule advised by his beneficiaries. As such, A.B.T. is not an appropriate/practicable mechanism for captive/co-generation, or for non-conventional sources of energy (wind, solar, biomass, mini-hydel, etc.), which are mostly unpredictable regarding their power supply capability. For example, payment of capacity charge in A.B.T. is dependent on MW availability declaration. If a figure cannot be committed for the whole of the next day, capacity charge itself cannot be determined. Further, the actual generation could vary widely, from the given schedule (e.g. due to changes in wind speed), and a plant could run up huge UI liability.

A.B.T. should therefore not be applied for such plants. They may continue on the single-part tariffs as presently specified by SERCs, or the entire power supplied by them into the grid may be treated as UI (and paid for by the concerned DISCOM at the frequency-linked UI rate). The logic for the latter is fairly simple. If a DISCOM receives one MW from a captive plant or wind farm, its drawal from the State grid would reduce by one MW. If it goes in underdrawal mode, it would receive UI payment for one MW, which it can pass on to the captive plant/wind farm, and remain financially immune.

25. UI for Open Access

Open access, as contemplated in the Electricity Act, 2003, means supply of power by entity-A to entity-B through the electricity grid. Power injection by A may not be constant, and may differ from contracted amount, by a varying degree from time to time. Similarly, power drawal by B may also vary and differ from the contracted amount. For example, the contract between the two parties may stipulate that A has to inject 10 MW, and B has to draw 9.5 MW (after accounting for transmission loss in the electricity grid). The actual injection and drawal may however be 9.0 and 10.0 MW respectively. Commercial treatment of such a situation, which is dynamic, could be very complex. The matter, however, becomes fairly simple if it is stipulated that B has still to pay to A for 10 MW at contracted rate, A has to pay at the UI rate to UI pool account for one MW of under-supply, and B has to pay at the UI rate for 0.5 MW of over-drawal to the UI pool account. This has already been specified by CERC for inter-State open access, and the same approach should be stipulated by the SERCs for intra-State open access. This necessarily requires installation of special energy meters for all open access customers, for recording energy 15-minutes block wise.

26. A.B.T. is generally not suitable for end-consumers of SEBs/ DISCOMs. As and when they are allowed open access, they would have to pay charges for contracted energy as per tariff bilaterally agreed with their supplier, and the UI charges for deviations from contracted schedule. This has to be duly taken care of while extending open access to end-consumers.

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