Comments on Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fifth Amendment) Regulation, 2016

Reference is invited to public notice dated 9th December,2016 and 3rd January,2017 seeking public comments on proposed draft amendment.

Regulation 2(1) (sss) – Definition of spinning reverse.

"The Capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are synchronized to the grid and able to effect the change in active power.

The proposed definition may be modified to indicate clearly that it should be on line and expected operational time. It is suggested that "within 10 minutes of a dispatch instruction by the system operator " may be appended at end of the clause. This is proposed as per prevailing regulations in other countries.

"The Capacity which can be activated on the direction of the system operator and which is provided by devices including generating stations/units, which are synchronized to the grid and able to effect the change in active power **within 10 minutes of a dispatch instruction by the system operator**.

Regulation 2(2) – It is proposed that definitions as given in Act and other Regulations of CERC

"Words and expressions used in these regulations and not defined herein but defined in the Act or other relevant CERC Regulations shall have the meaning as assigned to t hem under the Act or relevant CERC Regulation."

All definitions which are related to system operation should be in Grid code as it is parent or principle Regulation and if required consistency should be maintained by referring IEGC in the ancillary service regulation or other Regulations.

5.2 (f) (ii) – It is not clear why they should not be any reduction in generation, when frequency is range of from 50.00 – 50.04 Hz.

It is important that that unnecessary fuel should not be burned even for a block in view of its economic and environment effect. If commission had decided that target frequency is 50 Hz , then over generation should be avoided . In recent pasts, the trend of frequency remaining above 50.05 Hz for about 16-20% is due to this relax condition where action both by generator and system operator under ancillary operation starts at 50.05 Hz.

The governor operation (RGMO) in Indian context is different for industry standard FGMO. So it is requested that a graphical representation at explaining set point, droop and restricted mode is given.

The provision of RGMO as stipulated in IEGC 2010 was a temporary provision in view of then prevailing frequency profile and UI vector and it need to be and it will be replaced with FGMO

As mentioned in SOR of IEGC 2010

“Shri A. Velayutham has submitted that the tightening of frequency band from 49.2 – 50.3 Hz to 49.5 - 50.2 Hz is a welcome step in the right direction. However, it is necessary to further move very close to 50 Hz operation. Only then it may be possible to adopt full FGMO operation from present restricted FGMO operation. **Full FGMO may improve System performance through better Primary Control.** Variations in frequency can cause equipment, protection and control malfunction. Also it affects the quality of Industrial product. Internationally the frequency control through Secondary Control is between 20 and 200 mHz. (0.02- 0.2Hz).”

7.0 Statement of Reasons (SOR) on Amendment to IEGC, in 2012 reads as follows:

“3.4 We feel that if the generator is unable to carry out the RGMO in its units, then it should provide grid support through FGMO. It is clarified that the provision is made in view of the difficulties faced by certain generating companies to modify the machines to make them capable of operating in RGMO automatically. The proposed revision intends to allow the generators to operate the units in FGMO with manual intervention till the machine is modified for RGMO operation. We are of the view that the proposed amendment should be retained. **We are also conscious of the fact that ultimately machines have to be operated in FGMO for which the progressive narrowing down of frequency band will help.”**

In present grid condition with frequency remaining around 50 Hz for most of the time, and in view of sufficient generating capacity available, it is suggested that in place of RGMO which require special configuration than industry standard of FGMO, now FGMO should be implemented.

5.2 (h)

Suddenly is a qualitative terms and to check performance of Frequency response, it should be defined in numerical terms of either Δf or $\Delta f/\Delta t$. This is required so that frequency response during normal load variation i.e as required under 5.2(ii) (a) and under this clause for condition during contingency can be quantified and monitored.

Also it is felt that that the relaxation proposed for less than 25 MW is not under purview of CERC. It should be taken care in CEA grid standards.

So it is felt that in place of regulatory exemption, specific old hydro generating stations may be exempted based due to non -feasibility.

(ii) 5.2 (h)

(i) For hydro generation when water is available for more than 100% generation the condition of restricting generation upto 100% will result in water spillage and should not be applied.

While procuring generating machines for hydro station, the developer for complying with CEA regulation has already invested in 110% capacity and beneficiaries are already paying for this, so not utilizing this margin when water is available will lead to un- economic operation. In specific grid like conditions when sufficient spinning reserve is not available in regional/national grid, system operator, can ask them to keep this margin available .But in high hydro season, this margin should not be maintained at the cost of spillage.

(ii) Keeping 5% margin in all machine is uneconomic. System operation should calculate spinning reserve requirement and it can be done easily and allocate this quantity the based on merit order. It will be more economical if pit head stations are exempted from this provision. This is also as per international practice where small inefficient units which are on bar, are assigned this task.

In view of past experience of almost 15 years, it primary response is not coming through regulated entity , either existing provisions of Grid code should be implemented strictly or if necessary some economic incentive need to be provided for frequency response rather than keeping 5% margins on all machine unutlised. If due to non availability of secondary control (AGC) , FGMO response is not forthcoming , the issue of AGC need to be taken up urgently and only after one year of experience , other options like schedule restrictions may be considered.

While proposed draft regulation is not allowing scheduling beyond capacity corresponds to installed capacity (i.e Installed capacity – Auxiliary consumption)for this margin, it is not stated as to how generating company will be restrained from using this margin under deviation mechanism. If generator uses this for over generation(as 12% generation beyond schedule is permitted), at the time of grid requirement, this capacity would not be available to provide intended relief.

6. URS power

- While proposing two day ahead scheduling for utilising URS power in draft amendment , in explanatory memorandum it is not explained what difficulties are being experienced presently in utilisation of URS power . Commission in past had given three orders for utilisation of URS power . After these orders,

whether generating companies or users have expressed any difficulty in utilisation of URS power?

It is stated that to implement provisions of Tariff Policy 2016, the proposed amendment is proposed. However no quantification of available URS power has been done neither its cost and its benefit is described.

It must be kept in mind that with sufficient generation capacity available, there would always be some power which will remain un-requisitioned. Each beneficiary of Central sector generating stations have different demand pattern and power control portfolio. For economic and efficient power procurement with objective to minimise total cost of procurement of power, it would take decision to schedule power from CGS based on merit order, so imaging a situation where there will not be any URS power or taking decision to amend regulation on the basis of quantity of URS power may not be correct. Detailed analysis of variable cost of that URS power along with quantum and time of its availability is also important. With increasing penetration of renewables and obligation to purchase renewable, more and more quantity of URS power would be available depending on its variable cost. So in market environment, regulation should not try to interfere in economic operation. The regulation is perfect when it mimic the situation of free market.

In formulating the time line of two day scheduling, the open access customers and power exchange timing has not been considered. State utilities (beneficiary) is being asked to give its tentative drawl schedule when neither its open access customers nor itself has participated in PX and know what are its cleared volumes. Whether Commission is planning to shift Power Exchange time line also?

C- It may be clarified that whether how URS power which is being proposed to be treated as reallocation will be considered for computation of monthly Transmission charges under POC .Say for 7 day a new beneficiary avail URS of 100 MW power , whether this will be considered as LTA for transmission charges and original beneficiary will get corresponding benefit.

D- It has been proposed that Fixed charge liability would remain with original beneficiary. This was ok when beneficiary was having a right to recall. Now in the proposed amendment, **it right to recall has been withdrawal, then FC liability should also go.** In case generating company able to sale that, it should be recovered by generating company through short term sale.

A comparison of present URS and proposed in term of liability of original beneficiary is given below:

	Fixed cost	Variable cost	Incentive for original beneficiary	Right to recall	Transmission charge LTA
Present	Transferred to availing entity as it is treated as deemed allocation/temporary reallocation	Paid by availing entity	Complete Fixed cost liability corresponding to URS goes	Yes	Original beneficiary keep paying

Proposed	Proposed to be remained with original beneficiary	Paid by buying entity	50% Share in (sale price-Variable cost)	No	No clarity

A detail write up on difficulties in two day scheduling and a mechanism to utilize URS power is enclosed as annexure-I. Timeline mentioned in the proposed draft are not in line with timeline for Power Exchange transaction and it has conflict with time line with open access regulation and procedure issued therein .

	Present	Proposed
ISGS Declaration	0800 D-1	1300 D-2
RLDC to inform beneficiaries	1000 D-1	1500 D-2
Power Market Operation	1000-1500 Hrs	?
Beneficiary to inform schedule from ISGS *(why)	1500 D-1	1700 D-2 (Tentative)
Drawal Schedule by RLDC	1800 D-1	1900 D-2
URS status by RLDC	1800 D-1	1900 D-2
Revision by beneficiary if any	2200 D-1	
URS requisition by State	2300 D-1 and continuous	2000 D-2
Balance UR and Modification in tentative schedule		2100 D-2
Beneficiary to communicate final URS		1200 D-1
ISGS to sell in Power market		1200 D-1
Final Schedule by RLDC		1800 D-1

(*) The purpose of power market operation between 1000-1500 hrs on D-1 need to be understood. The state utility as well as its Open access customer bid in the power market. Only after ascertaining actual volume cleared through power exchange , Discoms/State utility can know how much amount of power it required to schedule from CGS. **This efficiency gain of market both for OA customer and Discom will vanish once new proposed mechanism is implemented.**

From above timeline, it is not clear when beneficiaries tentative schedule given of D-2 becomes its final schedule.

In present scenario of surplus power available, this drastic change of day ahead scheduling to two day ahead scheduling would not help in better utilisation of URS power.

It need to be seen in the context that earlier when power shortages were prevailing and CGS were able to sell this power under UI at high rate , the quantum of URS was less. Once country started getting more generation capacity , URS amount increased. Once surplus power of IPPs reached in power market, all high variable cost generating stations started getting less and less schedule and this benefited ultimate power consumer through lower price. Earlier under 2009 tariff regulation CGS were getting incentives on declared availability so they were not keen to utilize URS as they were getting 50 paise incentive without generating energy.

Commission through its path breaking regulation in the interest of consumers change the incentive payment mechanism form Availability to PLF and consumers are thankful to the Commission for this.

It can be easily established whatever URS power is there, this is due to load generation balance position and directly correlated with variable charges ,and no mechanism is going to help in making any appreciable change in utilisation of URS power. Even ancillary power mechanism is providing an easy exit to this stranded capacity in an economically inefficient way for time being. Once market based ancillary service start , the higher variable cost Ancillary in stack would be replaced by lower variable cost generation.

As brought out in NEP draft of CEA with more and more renewable coming, the PLF of thermal generating stations would keep decreasing and URS power would be increasing. This will send signal to utilities to beware of inefficient long term contracts.

So it is suggested that this proposal which will affect already established scheduling procedure and not expected to benefit much in terms of utilisation of URS power may be dropped.

Proposal (v) at end of clause 19

It is proposed that generating selling under bilateral short term and gone under unplanned shutdown would be allowed only one revision.

As scheduling is being done under day ahead basis, it should be allowed at least one revision per day. This is explained below:

Present situation:

A generator selling under bilateral short term say over a month goes under forced shutdown on 24th January and based on initial estimates , given restoration time of 28th January 00:00 hrs. At present if it revived on 26th January 1600 hrs , it will not be scheduled till 28th January and its injection if any would be considered as over injection and as 12% limit is applicable over schedule, it cannot inject even if plant is ready as its schedule is zero.

Similarly, if it is not revived till say 0900 hrs of 28th January, its full contract is scheduled from 0000 hrs and it had to pay heavy penalty under DSM.

Now it is proposed in draft amendments that it will be given one chance of revision.

The plant revival post a force shutdown is a complex activity and its correct estimation is a difficult thing. The revision of scheduling under force outage was provided to avoid unbalance drawl by buyer entity of STOA in case of forced shutdown. As scheduling is being done on daily basis, it will be prudent that the generator may be asked to give its plant status on daily basis before PX transaction i.e say at 9 AM, so that its buyer can make alternate arrangement.

This will avoid unnecessary deviation from schedule. The same intent was expressed in Statement of reason of first amendments of IEGC amendment while dealing with CEA suggestion on the matter.

" 43.10 On draft Regulation 6.5.19, CEA has suggested the following: "In case of a forced outage all generating stations irrespective of their nature of PPA, whether long term, medium term or short term, should be allowed to revise their schedule with the exception of schedules for day ahead collective transactions cleared through a power exchange. If large number of generating stations supplying power under long term, medium term and short term bilateral contracts are not allowed to revise their schedule under forced outage, it may result in serious grid imbalances."

CEA also submitted that in the UI Regulations, 2010, a limit has been put on under injection by the generator. To do so, the generators must have facility to revise their declaration in case of forced outages. However, this Regulation of proposed IEGC allows only generator with two part tariff and long term contract to revise their schedule in case of forced outage.

*Therefore to have a level playing field and to enable generators to generate close to their schedule, generators supplying through bilateral transactions under open access should be given right to revise declaration in case of forced outages. Since such events are not so common in a well maintained generating station**, a limit say once per day may** also be specified for this purpose.*

43.11 We are in agreement with the views of CEA. The issue of handling Grid imbalance is important and Regulation 6.5.19 has been modified to allow revision of schedules to a generator of capacity of 100 MW or more, in case of short term bilateral transactions, in case of forced outage, with the objective of not affecting the existing contracts, the revision of schedule shall be with the consent of the buyer till 31.07.2010. Thereafter, consent of the buyer shall not be a prerequisite for such revision of schedule."

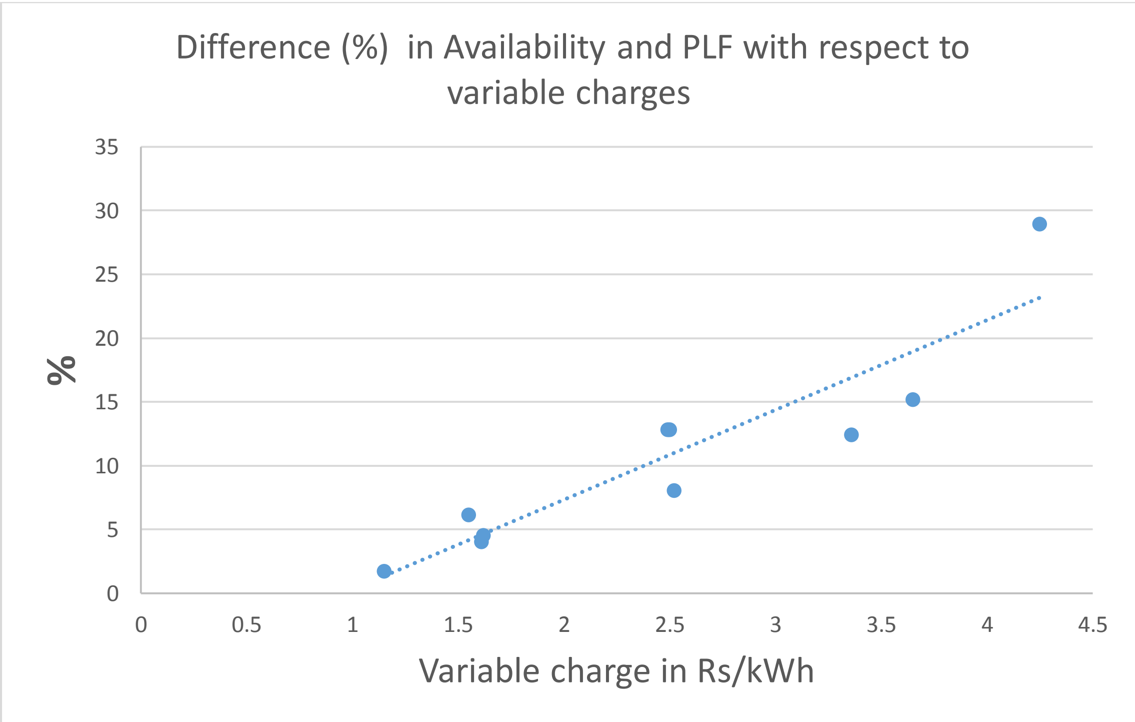
(Vijay Menghani)
Individual

Annexure-1

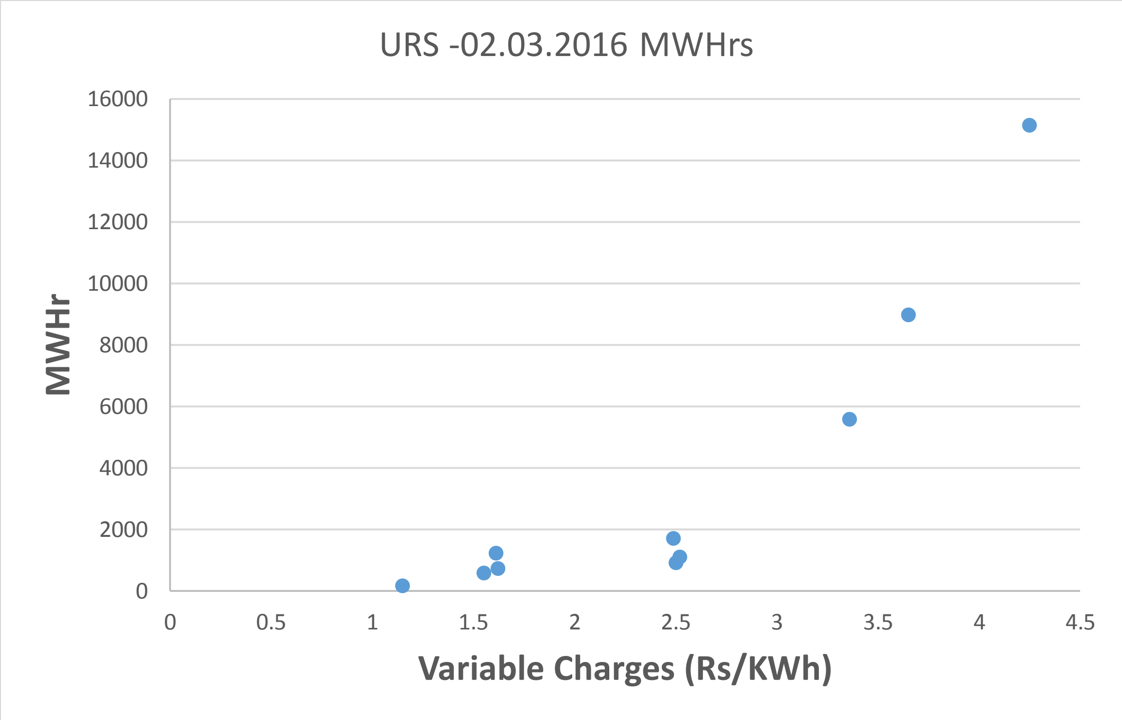
Utilization of URS Power : Difficulties in two day advance scheduling

1. It is to state that the quantum of URS which is existing, is small compared to total power scheduled from central sector generating stations. Also major part of URS is existing in costly stations which is not being scheduled by beneficiaries due to high variable cost. The price of such power is not competitive to make it attractive or saleable in power market. So for this, making a procedure by amending all existing scheduling procedures, timelines which not only require changes in regulatory regime but also has potential of disturbing corridor allocation time lines and power market price discovery, does not appear appropriate. The existing one-day advance scheduling procedure is based on Availability based tariff and Grid code since the year 2000, and just for harnessing small quantum of URS, it may not be appropriate to amend this procedure without consulting all stakeholders. As an estimate, only 1.5 % URS would be available at pit head stations and majority is available at high variable cost plants like Mauda and Jhajjar. Other than this, URS is available at gas based stations due to its high cost and it cannot be sold in the Power Exchange even at Variable cost. It may also be mentioned that major part of the URS is available during off peak hours.

2. An analysis of Regional Energy Accounts of Northern Region in respect of Central Sector generating stations for the year 2014-15 shows that the possible quantum of URS i.e difference between Declared availability and Plant load factor achieved is directly correlated with the variable cost of the generating stations.



3. Also URS available in NR for 2.3.2016 is having a direct correlation with Variable charges



4. The difficulties in implementation of the proposed two-day advance scheduling procedure under which schedule is to be fixed 24 hours in advance are given below:

i) International Experience:

While Day ahead scheduling is adopted in almost all markets, there is no power market wherein two day ahead scheduling is in vogue. So, the proposed scheduling procedure is not in line with international experience.

ii) Renewable Integration requires flexible scheduling:

The power sector is moving toward more and more distributed generation and renewable generation which necessitates flexibility in scheduling. To facilitate this, the scheduling as close to real time system operation is being allowed. In Europe and USA, schedule revision on 5 minutes and 10 minute ahead basis is being allowed. Keeping in view the planning for renewable capacity addition to the extent of 1,75000 MW in India, proposal of 2 day ahead scheduling wherein schedules are to be fixed 24 hours ahead basis, may come in the way of optimum utilization of Renewables.

iii) Hydro generation forecast:

Scheduling process for all ISGS generating stations needs to be on same time line. While it may be feasible for thermal stations to declare availability about 36 hrs ahead of actual operation, with higher uncertainty, for run of the river hydro stations it would be difficult as water availability assessment would be difficult.

iv) Operational Management by SLDC/ DISCOMS:

The uncertainties on Discom's sides are many as load is not entirely under their control. It may vary from projected load due to load forecasting error, weather dependent events and distributed generation. If a drawl schedule of the State is fixed 32 hours earlier than actual operation, it means freezing of schedule. So on the operating day, it cannot increase its schedule if required as its power is already sold. Besides, unbalanced scheduling right wherein generators can reschedule on the 4 block basis but Discoms cannot do it, is not considered justified.

v) Partial Generation schedule revision:
Consider the case of an ISGS indicating its DC as 100 MW, out of which 80 MW is scheduled to Discoms and 20 MW sold in market. If subsequently, generator revises its DC to 90 MW it is likely to pose problems in rescheduling as power Exchange transactions cannot be rescheduled. For DISCOM, balance power available would be 70 MW only, creating difficulties for the Discoms in managing the gap of 10 MW balance power.

vi) Uncertainty of tentative schedule:
Getting tentative schedule from states at 1700 hrs i.e. within two hour of Availability intimation by RLDCs (1500 hrs) practically does not appear feasible. SLDC before finalizing schedule needs to consider availability from its own generating stations and demand or load forecast from Discom(s). At present, five hours are provided for the same (10am to 3 PM).

Also using word “tentative “does not seem correct for initial drawl schedule because after this drawl schedule, power is going to be sold in PX and state cannot reclaim it saying it was tentative. So it is not clear what benefit this tentative schedule will bring as situation will remain fluid and uncertain.

It is not clear what is proposed to be done at 8 PM . Whether original beneficiaries is being given one more chance to take back its own entitlement or all beneficiaries of that particular generator are giving their requisition from URS power.what will be done if original beneficiary seek power from its entitlement at

Also it is not clear that

vii) Commercial implication:
The proposed procedure should also mention the implication if any, of retaining some ISGS capacity by state to manage its forecasting error and not scheduling it initially. As by retaining a capacity and not utilizing it, utility is already paying fixed charges, which itself is a burden on it. The provision in the tariff policy regarding sharing of benefit between ISGS and the beneficiary on 50:50 basis due to sale of URS power in the market, itself is likely to encourage the utilities to surrender their surplus shares in ISGS.

viii) Transmission Corridor allocation:

- Allocating corridor for supply of URS to utilities outside the region under STOA over inter- regional corridor is not in line with non-discriminatory open access principle. It also has potential of market distortion and is considered economically inefficient. STOA transaction is only possible upto 1500 hrs of D-1 day and processed after collective transaction. In the proposed procedure, these are given precedence over collective transaction. Also under present system, URS is known around 2200 hrs of D-1.

- The present sequence of transmission corridor allocation is Allocations/Long Term Access (LTA)**>** Medium Term Open Access (MTOA)**>** Advance/First Come First Served (FCFS) Short Term Open Access (STOA) **>** Power Exchange (PX) Day Ahead Market (DAM) **>**Contingency STOA **>** UnRequisitioned Surplus (URS) scheduling to beneficiaries only as per CERC Regulations/Orders.

ix) Market participation of States:

At present SLDCs are giving their final schedule after results of PX are out and they come to know whether their own buy bids have been cleared and how much volume has been cleared. Then for its uncleared volume, it will revise its schedule from CGSs keeping in view the merit order. This flexibility will not be available to SLDCs in the proposed procedure.

x) Open Access customer issue:

With the implementation of proposed scheduling procedure, DISCOMS are likely to face operational difficulty in managing requirements of open access customers, which revert back to Discom for supply of power in case their bids for purchase of power do not get cleared. As per universal obligation, State Discoms need to supply power to these customers without overdrawing from the grid.

5. Alternative proposal:

a) Both Mechanisms, the one suggested in tariff policy and the other in MOP note, can be implemented under existing scheduling mechanism.

b) At present scheduling is on a floating basis wherein both generators and beneficiaries have right to reschedule. Any mechanism which makes total schedule of state fixed is difficult to implement due to various reasons like load forecasting error, renewable integration and requirement of grid discipline. So part of flexibility in scheduling is to be retained.

c) The URS may be declared by the utilities in a broad manner and all of it may not depend on day-to-day declared capacity, entitlement calculation and requisition by state.

d) URS would be intimated on**" Prior consent basis**" well in advance. This system is working fine in present URS mechanism too.

e) As station wise scheduling is done, State would have choice to indicate its URS from an ISGS in 2 parts:

Part A –. Station-wise and time slot- wise URS as per tariff policy under which power would be sold by generator in power market and there would be no right to recall. This will be given well in advance (say 7 days ahead) on "Prior consent basis" and power can be sold by generator either in bilateral mode or through PX. In PX this need to be **bided in block bid basis else operationally it may not be possible to generate the power.**

Part B – URS as per MOP proposal /existing mechanism where option to recall remains. This part may be given on say 2 day ahead basis and can be utilized for scheduling between 5 PM to 10 PM. At present this time slot is used for day ahead contingency scheduling.

f) There would be no commercial implication for choosing option A i.e for capacity not scheduled initially or not utilized in real time, i.e deemed generation (variable charge) or incentive (additional charges considering deemed generation) should not be payable.

Proposing this will not be in line with CERC Tarff Regulations. Recently the incentive scheme has been amended from availability based incentive to PLF based incentive. If for unscheduled/unutilized portion, deemed generation is given then schedule plus deemed generation may be equal to availability and it may amount to Availability based incentive.

As an illustration, Delhi may intimate its URS from different ISGS in 2 parts as under, for implementation, as per existing scheduling procedure and revised provision in the Tariff policy.

Part A:

Station	Capacity	Days	Time (Hrs.)
APCL Jhajjar	267	1-15 March	00-24
Auriya Gas	74	1-15 March	00-24
Farakka	23	1-15 March	00-24
Dadri Gas	93	1-15 March	00-24
NCCPP DADRI	630	1-15 March	00-24
Anta Gas	45	1-15 march	00-24
Kahelgaon Stage 1	52	1-15 March	00-1200;2200-2400

Part B:

Station	Capacity allocated	Capacity for URS(MW)	Days	Time hrs
Kahelgaon Stage 1	52	52	1-15 March	1200-2200
Meija Unit 6	52	52	1-15 March	00-0800
Kahalgaon Stage 2	160	80	1-15 March	00-0800

(Vijay Menghani)
Individual