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Remuneration towards Frequency Regulation Service Provision in India through a Novel Capacity Linked Mechanism

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In India, the frequency regulation service has been provided by the generators, operating under the Free Governor Mode of Operation (FGMO), with certain regulatory basis prescribed by the Central Electricity Regulatory Commission (CERC) in Indian Electricity Grid Code (IEGC). No incentive is being provided towards the capacity reserved for frequency regulation service. In this paper, a capacity linked mechanism has been proposed in order to encourage the participants to provide regulation service.

Keywords: *unscheduled interchange mechanism, frequency regulation service, free governor mode of operation.*

1.0 INTRODUCTION

The power industry in India is at the verge of restructuring with the enactment of Electricity Act 2003 [7]. The Indian power system has been divided into five interconnected regional electricity boards (REBs), viz. Northern Regional Electricity Board (NREB), Eastern Regional Electricity Board (EREB), Western Regional Electricity Board (WREB), Southern Regional Electricity Board (SREB) and North Eastern Regional Electricity Board (NEREB). Each REB consists of some Interstate Generating Stations (ISGSs), Central Generating Stations (CGSs), Independent Power Producers (IPPs) and State Electricity Boards (SEBs). A gradual transition is taking place from the existing long term bilateral contracts (between states and IPPs/ ISGSs/CGSs for risk aversion) to power trading between states/Distribution companies (DISCOMs) with Short Term Open Access (STOA). In order to faciliate trading through a common platform, unbundling of SEBs and setting up of Power Exchange (PX), are paving the way for restructuring along with the increased complexity. It is essential for the System Operator (SO) to maintain system reliability and security and in market scenario, these can be achieved through the provision of Ancillary Services (AS). Frequency regulation is one of the ancillary services to be provided by market participants for maintaining frequency within Normal Operating Band (NOB).

The prevalent situation for frequency regulation in the Indian scenario is based on certain regulatory norms, having some pros and cons. In this paper, a mechanism to incentivise the procurement of frequency regulation service has been proposed to take care of the demerits of the prevailing method, incorporating the lost opportunity cost and usage cost.

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2.0 CONS OF PREVAILING FREQUENCY REGULATION MECHANISM

The only way to regulate frequency is to continuously maintain the balance between demand and supply on real time basis. It can be achieved through the automatic generation control and faster load curtailment/addition by load serving entities. In India, as per the CERC guidelines [9], all the generators are complied to operate under Free Governor Mode of Operation (FGMO) at all the time. In real time, the Unscheduled Interchange (UI) mechanism encourages the beneficiaries to make an immense profit out of it by managing its demand and captive generation in a strategic manner. Though, the UI mechanism and FGMO look simple, however, these have some shortcomings as described below.

The first and foremost technical shortcoming during operation under FGMO is the huge wear and tear losses to arrest transient swings in grid frequency. If a generator is not being compensated or provided incentives for its operation under FGMO to follow frequent load fluctuations, it will not be motivated for providing this service.

According to the CERC regulation [9], *a generator will be compensated upto 105% of the Declared Capacity in an interval and 101% of the Declared Capacity in average over the day through the UI mechanism, and in sections 4.8 (c) and 5.2 (f) of IEGC* [9], *it prescribes a compulsory operation of all generators under FGMO with no deliberations*. This will motivate the generators to set the load limiters in such a way that it delivers 105% of the Declared Capacity (DC) in an interval and 101% of the DC in average over a day. Hence, it will not be preferable for the generators to deliver power to its full capacity under FGMO, whenever required, due to lack of incentives. This may be the reason why generators are not operating in compliance with the CERC prescribed rules for the frequency regulation under sections 4.8 (c) and 5.2 (f).

The main commercial shortcoming is the inadequate compensation made towards the regulation service provision. UI is the only method adopted for compensation irrespective of the quality of performance. The quality of regulation service provided by the generators varies with respect to their droop, declared capacity, scheduled generation, settings of load limiters and dead band. The quality of performance mainly concerns about the response time. Also, when a generator has a higher incremental cost than the UI rate, while supplying the extra load, it will only pick up the minimum amount as per the regulation of the CERC and wait until the frequency goes below its threshold value for further supply of extra load. Therefore, the response time deteriorates due to lack of proper remuneration.

As per section 1.6 (iii) of the IEGC, the gas turbine/combined cycle power plants and nuclear power stations shall be exempted from sections 4.8 (c), 4.8 (d), 5.2 (e), 5.2 (f), 5.2 (g) and 5.2 (h) till the Commission reviews the situation [9]. Therefore, the gas turbine/combined cycle power plants and nuclear power stations would not participate in FGMO, though gas turbine stations can have the capability of operating with a droop of four percent.

There is a certain amount of compensation towards up regulation service, but no compensation for down regulation service. The CERC prescribed the regulation for FEMO as if it has to be reserved for the purpose of system security and therefore, it should be compensated in accordance with the reservation and must be shared among the participants those cause frequency fluctuations from the nominal value. The sharing must be based on the magnitude and randomness of the deviation from the scheduled value.

The RLDC, which acts as the Regional System Operator (RSO) does not forecast the necessary regulation requirement to maintain the reliability of the system. It is important to have the knowledge of regulation requirement for the system beforehand for procurement of regulation service from the generators.

3.0 PROPOSED CAPACITY LINKED REMUNERATION MECHANISM

The normal frequency operating band at present is 49.0 Hz to 50.5 Hz, which is maintained by adopting the Unscheduled Interchange (UI) mechanism along with some regulations prescribed for the FGMO by CERC. The balance between load and generation is maintained by self dispatch of generation and demand, encouraged through the frequency linked UI rate. The curve that represents the amended UI price vector is shown in Fig. 1 [11].

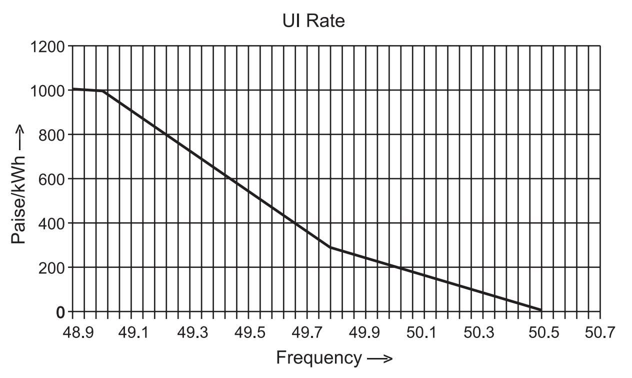

FIG. 1 UI PRICE VECTOR CURVE

The present frequency regulation prescribed by the CERC in Indian Electricity Grid Code (IEGC) is briefly described as follows [9];

1. It is mandatory for all generators, except the gas turbine/combined cycle power plants and nuclear power stations, to operate their units under Free Governor Mode of Operation (FGMO) with no deliberations, *viz.* setting the load limiters and introducing the dead band).

2. All generators, except the gas turbine/ combined cycle power plants and nuclear power stations, operate with a droop of 3% to 6%.

In order to achieve more transparency in the method and gain confidence of generators to provide adequate amount of Frequency Regulation (FR) service, it is necessary to shift the cap on generation in a suitable manner. Also, the generators must have been compensated for its loss of opportunity due to the capacity reserved for FGMO. The lost opportunity cost can be recovered by paying an incentive as fixed charge. The variable charge will be recovered by the UI mechanism as per the prevailing mechanism.

3.1 Setting up cap on generation for remuneration of FR service

The compensation up to 105% of the DC for an interval and 101% of DC for a day in average leads to a cap on generation. This guideline, by CERC, is set to avoid gaming of generators by declaring lower capacity in order to gain more in real time through UI mechanism. But, no generator will reserve its capacity to operate under FGMO, if it is not getting any incentive. Therefore, it is necessary to shift the cap for compensation from the present level to a suitable level decided based on the droop, scheduled generation, declared capacity and 105% of the maximum continuous rating (MCR). The compensation can be made to the reserved generation level determined by the flowchart as shown in Fig. 2. The proposed cap for compensation will be equal to the generation under FGMO when it is greater than 105% of DC and less than 105% of MCR, which is the only exception from the existing practice.

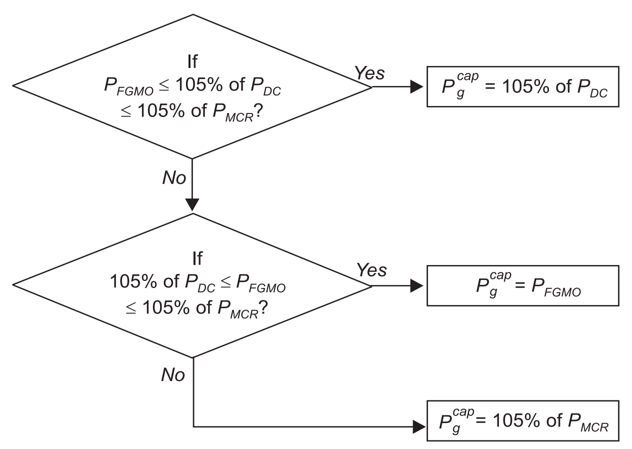

FIG. 2 FLOW CHART FOR SETTING THE CAP ON GENERATION FOR COMPENSATION OF FR SERVICE.

The power delivered under FGMO can be given by

$$P_{FGMO} = P_{SG} - \frac{\Delta f^{ru}}{R} \quad (1)$$

where, P_g^{cap} is the cap up to which the generators will be compensated for their reserve to provide frequency regulation service, P_{SG} is the scheduled generation, P_{DC} is the declared capacity of the generator, P_{MCR} is the maximum continuous rating of the generating unit, Δf^{ru} is the maximum allowable decrement in frequency in Hz from the normal frequency within the NOB and R is the droop/regulation in Hz per pu MW.

When all the generators would operate under FGMO with above cap, the frequency drop will be lesser than that with the cap as adopted under the present regulation. The change in frequency with respect to change in the load can be described mathematically as follows [1].

$$\Delta f = -\frac{M}{\beta} \quad (2)$$

where,

$$\beta = D + \frac{1}{R} = D + m \quad (3)$$

M is the pu MW change in total load in the area, β is area frequency response characteristic (AFRC), D is the sensitivity of frequency dependent load to change in frequency expressed in pu MW per Hz, R is the droop value expressed in Hz per pu MW.

The compensation towards provision of frequency regulation service will have two parts (i) fixed charges and (ii) variable charges or usage charges. Fixed charges compensate the lost opportunity cost for the capacity reserved towards frequency regulation service provision and variable charges compensate the fuel cost.

3.2 Recovery of lost opportunity cost as fixed charges

The capacity reserved for frequency regulation service must be compensated for its loss of opportunity cost to participate in the energy market. In case of the Indian power industry scenario, the capacity put under FGMO must be compensated on fixed charge basis as incentive. This incentive has to be decided by the CERC on the basis of governor type, droop, MCR and dead band of the units in service. Table 1 shows different types of turbines available with their type, droop and dead band along with the assumed fixed charges for the up and down regulation services.

In Fig. 3, $P_r^{-\Delta f}$ is the load set point up to which the governor acts freely without imposition of load limiter for the up regulation service provision. Above $P_r^{-\Delta f}$, the load limiter acts to limit the governor action up to the power

TABLE 1

FIXED CHARGES FOR DIFFERENT TYPES OF GENERATING UNITS

Governor type	Mechanical			Electro hydraulic		
Turbine MCR (MW)	< 20	20 - 150	> 150	< 20	20 - 150	>150
Over all droop (%)	3 - 5					
Dead band, % of rated speed	0.40	0.20	0.10	0.15	0.10	0.06
Fixed charges (paise/kWh) for regulation up service (c_0^{ru})	40	60	80	60	80	100
Fixed charges (paise/kWh) for regulation down service (c_0^{rd})	20	30	40	30	40	50

delivery point of P_g^{max}, which is equal to 105% of MCR. In Fig. 4, $P_r^{\Delta f}$ is the load set point above which the governor acts freely without imposition of load limiter for the down regulation service provision. Below $P_r^{\Delta f}$, the load limiter acts to limit the governor action upto the minimum power delivery point of P_g^{min}. $P_r^{-\Delta f}$ and $P_r^{\Delta f}$ can be computed by using equations (4) and (5), respectively.

$$P_r^{-\Delta f} = P_g^{\max} + \frac{\Delta f^{ru}}{R} \tag{4}$$

$$P_r^{\Delta f} = P_g^{\min} + \frac{\Delta f^{rd}}{R} \tag{5}$$

where, Δf^{ru} and Δf^{rd} are the maximum allowable decrease and increase in the frequency from its nominal value within the NOB, R is the droop or regulation in Hz per pu MW.

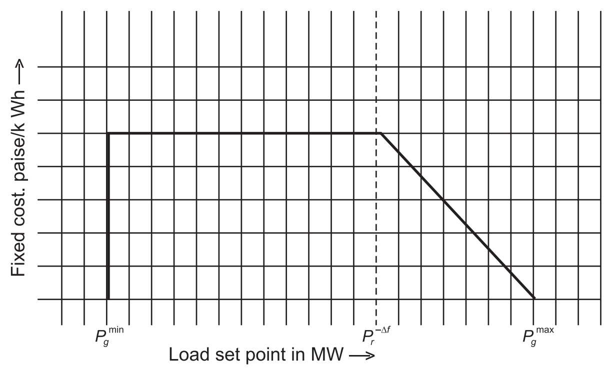

FIG. 3 FIXED CHARGES FOR UP REGULATION SERVICE.

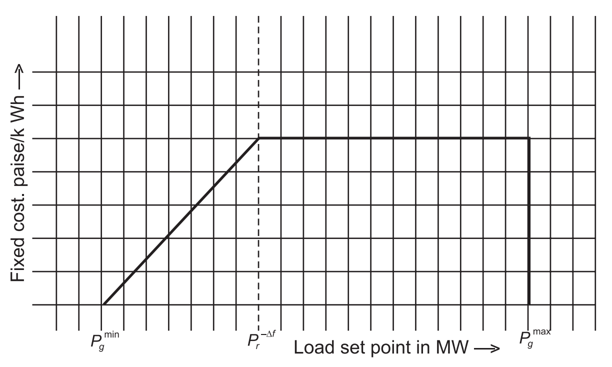

FIG. 4 FIXED CHARGES FOR DOWN REGULATION SERVICE.

The curves in Figs. 3 and 4 can be represented mathematically, as follows.

$$FC_{RU} = \begin{cases} c_0^{ru};\ \forall P_g^{\min} \le P_r \le P_r^{-\Delta f} \\ c_1^{ru};\ \forall P_g^{-\Delta f} \le P_r \le P_g^{\max} \end{cases} \tag{6}$$

$$FC_{RD} = \begin{cases} c_0^{rd};\ \forall P_r^{\Delta f} \le P_r \le P_g^{\max} \\ c_1^{rd};\ \forall P_g^{\min} \le P_r \le P_r^{\Delta f} \end{cases} \tag{7}$$

where,

$$c_1^{ru} = \left(\frac{c_0^{rd} P_g^{\max}}{P_g^{\max} - P_r^{-\Delta f}} \right) - \left(\frac{c_0^{ru}}{P_g^{\max} - P_r^{-\Delta f}} \right) P_r \tag{8}$$

$$c_1^{rd} = \left(\frac{c_0^{rd}}{P_r^{\Delta f} - P_g^{\min}} \right) P_r - \left(\frac{c_0^{rd} P_g^{\min}}{P_r^{\Delta f} - P_g^{\min}} \right) \tag{9}$$

c_0^{ru} and c_0^{rd} are the fixed charges as mentioned in Table 1. P_r is the operating load set point of the generating unit. FC_{RU} and FC_{RD} are the fixed charges per unit capacity of reserve for the up and down regulation services, respectively.

Therefore, by using equations (4) to (9), fixed charge per unit for providing frequency regulation service can be determined. It will vary from unit to unit depending upon the operating load set point of the generating unit. The fixed charges (lost opportunity charge) are expressed in paise/kWh. The capacity reserved for an interval can be compensated based on the flow chart shown in Fig. 5.

FR_{res}^{up} and FR_{res}^{down} are the capacity reserved for the up and the down frequency regulation service, which must be compensated. FR_{res}^{up} and FR_{res}^{down} are the fixed charges to be paid towards the compensation of the capacity reserved for the up and the down regulation services and the lost opportunity to keep reserve for the up regulation. Δf is the deviation of average system frequency over an interval from its nominal value.

After the computation of fixed charges for the capacity reserved for the frequency regulation services, it is necessary to recover it from the market participants. The total fixed charges can be prorated over the participants according to their deviations from scheduled drawal/dispatch in that particular interval.

$$Tot_{dev}^{sch} = \Delta P_g + \Delta P_d \tag{10}$$

$$\Delta P_g = \sum_{i=1}^{n_g} \Delta P_{gi} \tag{11}$$

$$\Delta P_d = \sum_{j=1}^{n_l} \Delta P_{di} \tag{12}$$

$$PF_{gi} = \frac{\Delta P_{gi}}{Tot_{dev}^{sch}} \tag{13}$$

$$PF_{di} = \frac{\Delta P_{di}}{Tot_{dev}^{sch}} \tag{14}$$

$$RFC_{gi} = PF_{gi} \text{ x } FC_{res} \tag{15}$$

$$RFC_{dj} = PF_{dj} \text{ x } FC_{res} \tag{16}$$

where, Tot_{dev}^{sch} is the sum of the total deviation of generation and drawal from the scheduled quantity that deteriorates the frequency. ΔP_g and ΔP_{gi} are the total deviation by generators and deviation by i^{th} generator from its schedule. ΔP_d and ΔP_{dh} are the total deviation by load serving entities and deviation by j^{th} load serving entity (LSE) from its schedule. PF_{gi} and PF_{dj} are the participation factor for i^{th} generator and j^{th} LSE, at which the participants will pay towards the fixed charges for capacity reserve of frequency regulation service. RFC_{gi} and RFC_{dj} are the fixed charges recovered from i^{th} generator and j^{th} LSE. FC_{res} is the total fixed charges paid towards the provision of the frequency regulation service.

3.3 Recovery of usage cost

The capacity reserved for FR service provision can be used instantaneously in real time, whenever required by the system. Therefore, a usage charge should be paid to the service providere based on the quantity utilised in a particular interval.

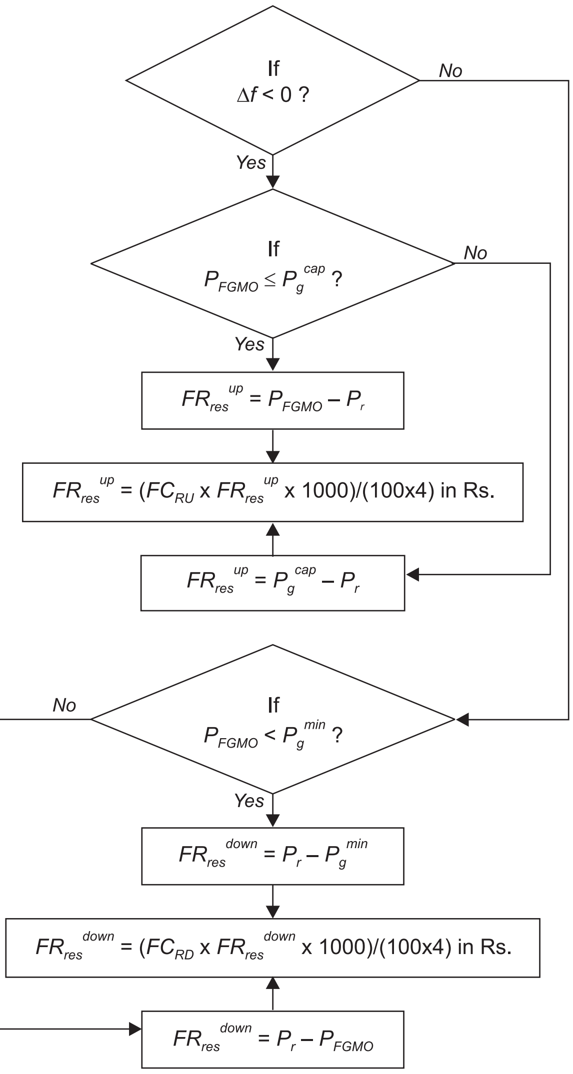

FIG. 5 FLOWCHART FOR COMPUTING LOST OPPORTUNITY COST COMPONENT OF REMUNERATION TOWARDS FR SERVICE.

Prevalent UI mechanism can be used to make the payments and recovery for the deviation from schedule that helps in frequency improvement and deterioration. By using UI price vector as shown in Fig. 1, UI rate can be computed at the average frequency during each interval. At 50 Hz, the UI rate is 150 paise/kWh and the rate has an incremental slope as the frequency decreases. It has been observed that, the average incremental costs of available generating units are less than the UI rate at 50 Hz. So, there will be no loss to generators, when operating under FGMO when the system frequency is below its nominal value. But, in case of liquid fuel generators, the average incremental cost varies from 434 paise/kWh to 680 paise/kWh. Hence, mostly these generators will operate when the system frequency will decrease drastically near about 49.5 Hz, at which these will get benefited from the UI charges.

The usage charges can be computed using UI mechanism and the algorithm used to determine the generation through unscheduled interchange from different units is shown in Fig. 6.

IF $P_g^{AG} \leq P_g^{cap}$

$$P_g^{UI} = P_g^{AG} - P_g^{SG}$$

ELSE

$$P_g^{UI} = P_g^{cap} - P_g^{SG}$$

END

FIG. 6 ALGORITHM USED TO DETERMINE THE GENERATION THROUGH UNSCHEDULED INTERCHANGE

Unscheduled interchanges in demands of the LSEs can be computed as

$$P_d^{UI} = P_d^{AD} - P_d^{SD} \tag{17}$$

P_g^{AG} is the actual generation in the interval, P_g^{AD} and P_g^{SD} are the actual and scheduled demand, respectively. P_g^{UI} and P_d^{UI} are the unscheduled volume of generation and demand.

In real time, the total load can never be equal to the total generation due to system loss. Hence, there will be a surplus or deficit of UI money. The surplus or deficit money can be shared among the receiving and paying entities on 50:50 basis and distributed based on their unadjusted payments and receipt to make the UI balance zero.

4.0 CASE STUDY

The advantages of the proposed remuneration mechanism over the existing mechanism have been demonstrated on the Northern Regional Electricity Board (NREB) system. In this system, central generating stations (CGSs) and inter-state generating stations (ISGSs) are considered as generators and states are considered as load serving entities. Table 2 shows the states and inter regional links with their scheduled/actual demand and scheduled/actual import/export in a typical interval when the average frequency is 49.62 Hz [13].

TABLE 2

SCHEDULED/ACTUAL DEMAND AND IMPORT/EXPORT OF STATES AND INTER-REGIONAL LINKS

States	SD* (MW)	AD# (MW)
Punjab	3471.1	3749.895
Haryana	1868	2717.747
Rajastan	1788.4	2256.834
Delhi	2167.7	2162.93
Uttar Pradesh	3121.8	3853.076
Uttarakhand	359.5	101.8697
Himachal Pradesh	–84.5	–151.684
Jammu and Kashmir	932.6	570.607
Chandigarh	216.2	192.9759
NFF	5.8	2.97957
Railway	59.5	63.696
MP (Au-Mlnpur)	0.0	70.704
MP (Kota/Mrk-Ujjain)	0.0	0.0
Nepal (Tnk-Mhngar)	8.7	0.0
Bihar	24.25	17.472
ER-NR Link	–1260.02	–1955.68
WR-NR	–276.111	–750.387
Total	**12402.92**	**12903.03**
ΔP_d = 500.11 MW		

*Scheduled Demand #Actual Demand

Utilising the algorithm as described in Fig. 2, the generation cap up to which the compensations are to be availabe has been computed. This cap will help to maintain more reserve for frequency regulation service as well as encourage generators to follow the load variation through FGMO without any hesitation. In Table 3, declared capacity, scheduled generations and actual generations are shown. The reserves under the present practice and with the proposed cap on generation have been computed, which are shown in Table 4.

TABLE 3

DECLARED CAPACITY, SCHEDULED GENERATION AND ACTUAL GENERATION

Units Committed	DC#	SG*	AG**
NTPC			
Singrauli (1 x 200 + 2 x 500)	1215	1215	1222.3
Rihand-I (2 x 500)	935	935	938.17
Rihand-II (2 x 500)	960	960	968.01
Dadri (T) (4 x 210)	785	785	808.29
Unchahar-I (2 x 210)	392	392	399.49
Unchahar-II (2 x 210)	397	397	400.65
Unchahar-III (1 x 210)	200	200	202.81
Dadri (G) (4 x 130.19)	505	466.9	504.75
Auraiya (G) (4 x 111.19)	415	343.5	339.07
Anta (G) (3 x 88.71)	256	240.3	250.22
NHPC			
Baira Siul (3 x 60)	179	60	60.864
Salal (6 x 115)	645	645	648.38
Tanakpur (3 x 31.4)	93	93	93.408
Chamera-I (3 x 180)	534	534	540.22
Chamera-II (3 x 100)	297	297	297.6
URI (4 x 120)	474	474	476.36
Dhauli Ganga (4 x 70)	277	277	284.58
Dulhasti (3 x 130)	386	386	395.64
BBMB			
Bhakra (5 x 108 + 3 x 157)	926	926	929.15
Dehar (4 x 165)	580	580	581.22
Pong (5 x 66)	325	325	323.78
NPC			
NAPP (1 x 220)	131	131	130.54
RAPP (B) (2 x 220)	242	242	240.54
Nathpa Jhakri (6 x 250)	1482	1482	1484.4
Tehri (3 x 200)	490	490	567.23

#Declared capacity *Scheduled generation **Actual generation

Frequency dependency of loads is assumed to vary linearly with the frequency. Thus, one per cent increase in the frequency leads to one per cent increase in the load and vice versa. Therefore, the value of D in equation (3) has been take as 0.015 pu MW/Hz. I/R in equation (3) depends upon the reserve available for FGMO operation and has been found to be 0.0487 pu MW/Hz with the present cap and 0.1029 pu MW/Hz with the proposed cap. By using equation (2), with the computed value of β ffrom equation (3) and assuming 0.0294 pu MW increment of load in the region, the change in the frequency from its nominal value is found to be –0.46 Hz and –0.25 Hz with the present and the proposed cap, respectively. It can be observed from the above analysis that the proposed cap helps in keeping the frequency more

TABLE 4

FR RESERVE FOR PRESENT AND PROPOSED CAP SETTING

Units Committed	FR res (Proposed)	FR res (Present)
NTPC		
Singrauli (1 x 200 + 2 x 500)	45	45
Rihand-I (2 x 500)	115	46.75
Rihand-II (2 x 500)	90	48
Dadri (T) (4 x 210)	97	39.25
Unchahar-I (2 x 210)	49	19.6
Unchahar-II (2 x 210)	44	19.85
Unchahar-III (1 x 210)	20.5	10
Dadri (G) (4 x 130.19)	79.898	63.35
Auraiya (G) (4 x 111.19)	123.5	92.55
Anta (G) (3 x 88.71)	39.137	28.5
NHPC		
Baira Siul (3 x 60)	72	72
Salal (6 x 115)	79.5	32.55
Tanakpur (3 x 31.4)	5.91	4.65
Chamera-I (3 x 180)	33	26.7
Chamera-II (3 x 100)	18	14.85
URI (4 x 120)	30	23.7
Dhauli Ganga (4 x 70)	17	13.85
Dulhasti (3 x 130)	23.5	19.3
BBMB		
Bhakra (5 x 108 + 3 x 157)	135.55	46.3
Dehar (4 x 165)	113	29
Pong (5 x 66)	21.5	16.25
NPC		
NAPP (1 x 220)	88	6.55
RAPP (B) (2 x 220)	176	12.1
Nathpa Jhakri (6 x 250)	93	74.1
Tehri (3 x 200)	140	24.5
Total	**1748.995**	**828.65**

stable than the present cap. With the present cap, frequency settles at 49.54 Hz and with the proposed cap, frequency settles at 49.75 Hz when all the available reserve is obtained trough FGMO for the same load change. In Table 5, system data along with the frequency correction for three cases, *viz.* without FGMO, with FGMO (present cap) and with FGMO (proposed cap) are shown.

TABLE 5

SYSTEM DATA AND FREQUENCY CORRECTION

Area rating in MW	17002.77		
Scheduled load in MW	12877		
Load increase in MW	500.1094		
Load increase in pu MW	0.029413		
D in pu MW/Hz	0.015147		
	Without FGMO	With FGMO	
		Present	Proposed
$1/R$ in pu MW/Hz	0	0.0487	0.1029
Δf in Hz	–1.942	–0.46	–0.25
f in Hz	48.058	49.54	49.75

In Table 4, the committed generating units are represented by '1' and those, which are not committed, are represented by '0'. Also, the cap upto which the compensations are available, along with the load set point of each unit in a particular operating interval is also shown. Capacity reserved for the frequency regulation service, along with the fixed charge for each unit, have been computed using the algorithm given in Fig. 5 and equations (4) to (9), as described in section 3.2. These are shown in Table 6. Net fixed compensation for each unit and total for the generators has been shown along with net capacity reserve and fixed charge for the system.

The recoveries of fixed charges from different participants have been computed, using equations (10) to (16), which are shown in Table 8. It can be observed from Tables 7 and 8 that the net recovery is equal to the net payment towards the fixed charges for the frequency regulation service provision.

The usage charges for FR service provision have been computed using UI mechanism as described in Fig. 6 and equation (17). The payments and recovery to and from the participants for the proposed and the present cap settings are shown in Tables 9 and 10, respectively. It is observed that the recovery by the UI mechanism is always higher than the payments when the frequency is below nominal frequency. Hence, the surplus UI amount has been distributed in the ratio of 50:50 among receiving and paying entities and prorated over their unadjusted UI amount. In Tables 9 and 10, both the unadjusted and adjusted UI payments and recovery with the proposed and the present approaches are shown. In case of the adjusted UI payment and recoverey, the surplus is zero i.e. the net balance in UI acount is zero.

From Tables 9 and 10, it can be observed that the payment towards usage with the present

TABLE 6

FIXED CHARGES FOR FREQUENCY REGULATION SERVICE PROVISION FOR SINGRAULI GENERATING STATION

Unit capacity (MW)	**UC**	**Load set point (MW)**	**Cap on unit (MW)**	**c_0^{ru} (paise/ kWh)**	**FR reserve (MW)**	**FC (paise/ kWh)**	**Net FC (Rs)**
200	1	202.5	210	100	7.5	7.5	140.63
200	0	0	0	100	0	0	0
200	0	0	0	100	0	0	0
200	0	0	0	100	0	0	0
200	0	0	0	100	0	0	0
500	1	506.25	525	100	18.75	9.375	439.45
500	1	506.25	525	100	18.75	9.375	439.45
Total		**1215**	**1260**		**45**		**1019.53**

approach is much more than the proposed approach because of the substantial frequency reduction in case of the proposed approach through FGMO as compared to the prevailing scenario. In present scenario, Rs. 18,53,438.00 has to be paid as usage charge, where as with the proposed scenario, Rs. 13,15,141.00 has to be paid, thus resulting in, a reduction of Rs. 5,38,297.00 with an additional fixed charge payment of Rs. 1,70,245.20. Therefore, the proposed method seems to be much more effective from technical and economical point of view.

For illustration prupose, only the detailed results of Singrauli generating station have been shown in Table 6. Brief results for other stations are shown in Table 7.

TABLE 7

FIXED CHARGES FOR FREQUENCY REGULATION SERVICE PROVISION

Generating Station	Load set point (MW)	FR reserve (MW)	Net FC (Rs)
Singrauli	1215	45	1019.53
Rihand-I	935	115	6612.6
Rihand-II	960	90	5062.6
Dadri (T)	785	97	7000.8
Unchahar-I	392	49	3573
Unchahar-II	397	44	2881
Unchahar-III	200	20.5	1250.7
Dadri (G)	466.88	79.9	6129.2
Auraiya (G)	343.5	123.496	13716.8
Anta (G)	240.3	39.138	2302.14
Baira Siul	60	72	10800
Salal	645	79.5	3434.94
Tanakpur	93	5.91	139.044
Chamera-I	534	33	1008.33
Chamera-II	297	18	405
URI	474	30	703.12
Dhauli Ganga	277	17	387.052
Dulhasti	386.01	23.4999	531
Bhakra	926	135.55	7873.45
Dehar	580	113	9673.6
Pong	325	21.5	525.3
NAPP	131	88	22000
RAPP (B)	242	176	44000
Nathpa Jhakri	1482	93	2883
Tehri	489.99	140.001	16333.2
Total		**16333.2**	**170245.2**

TABLE 8

RECOVERY OF FIXED CHARGES FOR FR SERVICE PROVISION

Participants	Participation factor	Recovery (Rs)
Generating Station		
Singrauli	0	0
Rihand-I	0	0
Rihand-II	0	0
Dadri (T)	0	0
Unchahar-I	0	0
Unchahar-II	0	0
Unchahar-III	0	0
Dadri (G)	0	0
Auraiya (G)	0.0018	312.8534
Anta (G)	0	0
Baira Siul	0	0
Salal	0	0
Tanakpur	0	0
Chamera-I	0	0
Chamera-II	0	0
Uri	0	0
Dhauli Ganga	0	0
Dulhasti	0	0
Bhakra	0	0
Dehar	0	0
Pong	0.0005	86.1583
NAPP	0.0002	32.4859
RAPP (B)	0.0006	103.1074
Nathpa Jhakri	0	0
Tehri	0	0
State		
Punjab	0.1157	19689
Haryana	0.3525	60007
Rajastan	0.1943	33079
Delhi	0	0
Uttar Pradesh	0.3034	51646
Uttarkhand	0	0
HP	0	0
J & K	0	0
Chandigarh	0	0
NFF	0	0
Railway	0.0017	296.33
MP (Au-Mlnpur)	0.0293	4993.2
MP (Kota/Mrk-Ujjain)	0	0
Nepal (Tnk-Mhngar)	0	0
Bihar	0	0
ER-NR Link	0	0
WR-NR	0	0
Total		**170245.2**

TABLE 9

PAYMENT AND RECOVERY OF USAGE CHARGES FOR FR SERVICE PROVISION WITH PROPOSED APPROACH

	Unadjusted		Adjusted	
Participants	**Payment (Rs)**	**Recovery (Rs)**	**Payment (Rs)**	**Recovery (Rs)**
Generating Station				
Singrauli	4236.49	0	4525.08	0
Rihand-I	1839.68	0	1965	0
Rihand-II	4648.54	0	4965.19	0
Dadri (T)	13516.2	0	14436.9	0
Unchahar-I	4346.76	0	4642.85	0
Unchahar-II	2118.25	0	2262.54	0
Unchahar-III	1630.76	0	1741.84	0
Dadri (G)	21964.8	0	23461	0
Auraiya (G)	0	2570.914		2416.786
Anta (G)	5756.99	0	6149.14	0
Baira Siul	501.415	0	535.571	0
Salal	1961.55	0	2095.17	0
Tanakpur	236.779	0	252.908	0
Chamera-I	3609.73	0	3855.61	0
Chamera-II	348.205	0	371.924	0
Uri	1369.61	0	1462.9	0
Dhauli Ganga	4398.99	0	4698.64	0
Dulhasti	5594.49	0	5975.58	0
Bhakra	1828.08	0	1952.6	0
Dehar	708.017	0	756.245	0
Pong	0	708.0169	0	665.5709
Napp	0	266.9572	0	250.953
Rapp (B)	0	847.2989	0	796.5029
Nathpa Jhakri	1392.82	0	1487.7	0
Tehri	44819.8	0	47872.8	0
State				
Punjab	0	161799.3	0	152099.3
Haryana	0	493116.3	0	463553.8
Rajastan	0	271832.1	0	255535.6
Delhi	2785.64	0	2975.39	0
Uttar Pradesh	0	424403.9	0	398960.7
Uttarkhand	149513	0	159698	0
HP	38987.4	0	41643.1	0
J & K	210078	0	224388	0
Chandigarh	13475.5	0	14393.5	0
NFF	1636.8	0	1748.29	0
Railway	0	2435.114	0	2289.128
MP (Au-Mlnpur)	0	41032.48	0	38572.56
MP (Kota-Ujjain)	0	0	0	0
Nepal (Tnk-Mhngar)	5048.97	0	5392.9	0
Bihar	3933.56	0	4201.5	0
ER-NR Link	403744	0	431246	0
WR-NR	275239	0	293987	0
Total	**1231269**	**1399012**	**1315141**	**1315141**
UI Surplus	**167743**		**0**	

TABLE 10

PAYMENT AND RECOVERY OF USAGE CHARGES FOR FR SERVICE PROVISION WITH PRESENT APPROACH

	Unadjusted		Adjusted	
Participants	**Payment (Rs)**	**Recovery (Rs)**	**Payment (Rs)**	**Recovery (Rs)**
Generating Station				
Singrauli	5970.52	0	6377.22	0
Rihand-I	2592.68	0	2769.29	0
Rihand-II	6551.22	0	6997.47	0
Dadri (T)	19048.4	0	20346	0
Unchahar-I	6125.92	0	6543.21	0
Unchahar-II	2985.26	0	3188.61	0
Unchahar-III	2298.24	0	2454.79	0
Dadri (G)	309551	0	33063.7	0
Auraiya (G)	0	3623.209		3405.996
Anta (G)	8113.37	0	8666.04	0
Baira Siul	706.648	0	754.784	0
Salal	2764.43	0	2952.74	0
Tanakpur	333.695	0	356.426	0
Chamera-I	5087.21	0	5433.74	0
Chamera-II	490.728	0	524.155	0
Uri	1930.2	0	2061.68	0
Dhauli Ganga	6199.53	0	6621.83	0
Dulhasti	7884.36	0	8421.43	0
Bhakra	2576.32	0	2751.82	0
Dehar	997.814	0	1065.78	0
Pong	0	997.8137	0	937.9943
Napp	0	376.2248	0	353.67
Rapp (B)	0	1194.105	0	1122.518
Nathpa Jhakri	1962.91	0	2096.62	0
Tehri	63164.9	0	67467.5	0
State				
Punjab	0	228025	0	214354.8
Haryana	0	694952.7	0	653290
Rajastan	0	383095	0	360128.3
Delhi	3925.82	0	4193.24	0
Uttar Pradesh	0	598115.7	0	562258.4
Uttarkhand	201710	0	225064	0
HP	54945.2	0	58687.9	0
J & K	296064	0	316232	0
Chandigarh	18991.2	0	20284.8	0
NFF	2306.75	0	2463.88	0
Railway	0	3431.825	0	3226.085
MP (Au-Mlnpur)	0	57827.39	0	54360.61
MP (Kota-Ujjain)	0	0	0	0
Nepal (Tnk-Mhngar)	7115.56	0	7600.25	0
Bihar	5543.59	0	5921.21	0
ER-NR Link	568999	0	607758	0
WR-NR	387896	0	414319	0
Total	**1735238**	**1971639**	**1853438**	**1853438**
UI Surplus	**23401**		**0**	

5.0 CONCLUSION

Frequency regulation service is one of the ancillary services provided by generators to balance the continuous small variation in the demand. In the Indian power sector, FGMO is the sole mechanism to provide this service as per the stipulations prescribed by CERC in IEGC. There are cerain shortcomings as discussed in this paper, which discourages the participants to provide this service. In this paper, a capacity linked compensation method has been proposed to encourage participants for keeping reserve towards FGMO service. The results demonstrate the effectiveness of the proposed approach over the existing practice in terms of both technical and economical benefits.

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