स्वांतत्र्याचा अमृत महोत्सव

MAHAVITARAN
Maharashtra State Electricity Distribution Co. Ltd.
(A Government of Maharashtra Undertaking)
(CIN: U40109MH2005SGC153645)

DR. MURHARI KELE
Director (Commercial)

Ref. No. CE/PP/CERC GC 2022/ № 2 7 2 5 1 **DATE:** 18 OCT 2022

To,
The Secretary,
Central Electricity Regularity Commission,
3 rd & 4th Floor, Chanderlok Building,
36, Janpath, New Delhi-110001,

Sub: Submission of comments /suggestions on proposed Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022.

Ref: 1) No. L-1/265/2022/CERC dated 07.06.2022

Respected Sir,

This has reference to the public notice under ref. (1) seeking the comments on proposed Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022. In this regards, please find herewith MSEDCL's comments/suggestions attached herewith as **Annexure A**.

It is kindly requested to consider, same while finalizing the proposed Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022.

Thanking you.

Yours Faithfully,

Encl: As above.

Director (Commercial)
MSEDCL

Copy to:
Chairman & Managing Director, MSEDCL, CO,Mumbai

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Name of Stakeholder – **MSEDCL**

Sr. No.	Clause No.	Draft Regulations	Suggestion of Stakeholder
	Chapter 2:- Resource Planning Code		
1	Regulation (5)- Integrated Resource Planning, Sub regulation (2)- Demand (i)	Demand Forecasting: - (i) Each distribution licensee within a State shall estimate the **demand** in its control area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, for the next **five (5)** years starting from **1st April of the next year** and submit the same to the STU by **31stJuly every year**. The demand estimation shall be done using trend method, time series, econometric methods or any state of the art methods and shall include daily load curve (hourly basis) for a typical day of each month.	It is submitted that DISCOMs shall be allowed to revise its Demand Estimation and Generation Adequacy **once in every quarter** in case there is a change in the demand and supply trend.
2	Regulation (5)- Integrated Resource Planning, Sub regulation (3)- Generation Resource	(a)After the demand estimation as per sub-Regulation (2) of this Regulation, each distribution licensee shall (i) assess the existing generation resources and identify the **additional generation** resource **requirement** to **meet the estimated demand** in different time horizons, and (ii) prepare generation resource **procurement plan.** (b) Assessment of the existing generation resources shall be done with due regard to their **capacity contribution to meet the peak demand.** **(c)** Generation **resource procurement planning** (specifying procurement from resources under State control area and regional control area) shall be undertaken in different time horizons, namely **long-term, medium term and short-term** to ensure	It is submitted that peak demand occurs for very short duration hence assessment of generation resources on the basis of peak demand may result in additional burden of fixed cost to the DISCOMs. Hence the assessment of the existing generation resources shall be done with due regard to their **Average Peak demand.** It is also submitted that, keeping Reserve margin for every DISCOM in the country may lead to a large capacity in idle condition which further will increase the fixed cost burden on DISCOMs. Hence it is suggested that keeping extra reserve margin beyond the reserves

		(i) **adequacy** of generation resources and (ii) **planning reserve margin** (PRM) taking into account loss of load probability and energy not served as specified by CEA. (f) After considering the demand forecasting and the generation resource procurement planning carried out based on the principles specified under this Regulation, **each distribution licensee shall ensure demonstrable generation resource adequacy** as specified by the respective SERC for the **next five (5) years** starting 1st April of the next year. Failure of a distribution licensee to meet the generation resource adequacy target approved by the SERC shall render the concerned distribution licensee liable for payment of **resource adequacy non- compliance charge** as may be specified by the respective SERC (g) For the sake of uniformity in approach and in the interest of optimality in generation resource adequacy in the States, FOR may develop a **model Regulation stipulating inter alia the methodology for generation resource adequacy assessment, generation resource procurement planning and compliance of resource adequacy target by the distribution licensees**	specified in CERC Ancillary Service Regulations may be avoided. Though DISCOMs can provide a plan under resource adequacy showing sufficient available generation to meet the forecasted demand, ensuring that the generation availability is met in real time is beyond control of the Distribution Licensee. Therefore it is suggested that it would not be justified to impose resource adequacy non-compliance charges on DISCOMs. It is submitted that **resource adequacy non-compliance charges should not be imposed** on distribution licensees having sufficient contracted generation capacity.
Chapter 5:- Commissioning and Commercial Operation Code			
3	Regulation (27) Declaration of Commercial Operation (DOCO) and Commercial	A **generating station** or unit thereof or a **transmission system** or **an element thereof** or **ESS may declare** commercial operation as follows and inform CEA, the concerned RLDC, the concerned RPC and its beneficiaries: (c) **Transmission** System	In case a transmission element is commissioned as per schedule and corresponding generating station or upstream and downstream network is not available to connect to the commissioned transmission element, then in such case, the

	Operation Date (COD) , Sub regulation (1)	(i) The commercial operation date in case of an Inter-State Transmission System or an element thereof shall be the **date declared by the transmission licensee on which the Transmission System or an element thereof is in regular service at 0000 hours after successful trial operation** for transmitting electricity and communication signal from the sending end to the receiving end as per Regulation 23 and submission of declaration as per Regulation 26(3) of these regulations: Provided that the commercial operation date of a transmission element which is a part of Associated Transmission System (ATS) shall be **declared only after successful trial run of the last element of the said ATS:** Provided further that where only some of the transmission elements of the ATS have achieved successful trial run and the Connectivity grantee under GNA Regulations seeks commercial operation of such element for utilization by such grantee and is agreed by the Central Transmission Utility, the commercial operation date of such transmission elements of the ATS may be declared by the transmission licensee as per this Regulation: Provided also that where only some of the transmission element(s) of the ATS have achieved successful trial run and if the operation of such transmission elements are certified by the concerned Regional Power Committee(s) for improving the performance, safety and security of the grid, the commercial operation date of such transmission element(s) of the ATS may be declared by the transmission	entity (generating station or transmission company) responsible for delay in commissioning of upstream and downstream network or generating station **shall be responsible to bear the charges of the commissioned transmission element. Hon'ble APTEL has clearly stated in its various judgements**. Hence there is no need to approach the Commission in such cases. The clause may be modified accordingly.

		licensee as per this Regulation: Provided also that in case a transmission system or an element thereof executed under regulated tariff mechanism is prevented from regular service on or after the scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate petition along with a certificate from the CTU to the effect that the transmission system is complete as per the applicable CEA Standards, for approval of the commercial operation date of such transmission system or an element thereof: Provided also that in case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee may declare deemed COD of the ISTS in accordance with the provisions of the Transmission Service Agreement after obtaining a certificate from the CTU to the effect that the transmission system is complete as per the specifications of the bidding guidelines and applicable CEA Standards. (ii) The COD of a transmission element of the transmission system under Tariff Based Competitive Bidding shall be declared only after declaration of COD of all the pre-required transmission elements as per the Transmission Services Agreement: Provided that in case any transmission element is required in	

		the interest of the power system as certified by concerned RPC(s), the COD of the said transmission element may be declared prior to the declaration of COD of its pre- required transmission elements.	
		Chapter 6 Operating Code	
4	Regulation (30) Frequency Control and Reserves , Sub regulation(2)	The NLDC, RLDC and SLDC shall ensure that the grid frequency remains close to 50 Hz. And ensure that the frequency is restored within the allowable band of 49.95-50.05 Hz. at the earliest	As per existing IEGC-2010 (Amendments thereof) the frequency band is **49.90 to 50.05 Hz** which is very well proven to be a safe band for the grid. Hence it is requested to continue with the same frequency band of **49.90-50.05 Hz** in the proposed Grid Code Regulations.
5	Regulation (31) Operational Planning , Sub regulation (2)	**Demand Estimation** (a) **Each SLDC** shall carry **out demand estimation as part of operational planning** after duly factoring in the demand estimation done by STU as part of resource adequacy planning referred to in clause (2) of Regulation (5) of these regulations. **Demand estimation by SLDC shall be for both active power and reactive power incident** on the transmission system based on the **details collected from distribution licensees,** grid-connected distributed generation resources, captive power plants and other bulk consumers embedded within the State. (b) **Each SLDC shall develop methodology for daily, weekly, monthly, yearly demand estimation in MW** and **MWh** for operational analysis as well as resource adequacy purposes. Each SLDC, while estimating demand may utilize state of the art tools, weather data, historical data and any other data. For this purpose, all distribution licensees shall	Based on the various initiatives taken by MoP, MNRE, state designated agencies and further the renewable policy of State government, the penetration of renewable energy like solar, wind, biomass etc. have broadly impacted the overall demand estimation of distribution licensee/SLDC. As it is broadly known that most of the renewable power is not firm power, it is necessary that **separate guidelines for demand estimation of RE rich state may be issued** by appropriate forum so as to bring uniformity in demand estimation by all States/DISCOMs. It is further suggested that **Energy Storage System (ESS) may also be included as a part of renewable energy sources** to maintain peak demand of the area and the demand forecasting may be estimated considering the charging/

		maintain historical database of demand. (c) **The demand estimation by each SLDC shall be done on day ahead basis with time block wise granularity for the daily operation and scheduling**. In case, SLDC observes major change in **demand in real time** for the day, it shall immediately submit the revised demand estimate to concerned RLDC for demand estimate correction. (d) **Each SLDC shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVAr** on monthly and quarterly basis for the nodes 132 kV and above for preparation of scenarios for computation of TTC and ATC by the concerned RLDC and NLDC. (e) **SLDC shall also estimate peak and off-peak demand** (active as well as reactive power) on weekly and monthly basis for load - generation balance planning as well as for operational planning analysis, which shall be a part of the operational planning data. The demand estimates mentioned above shall have granularity of a time block. The estimate shall cover the load incident on the grid as well as net load incident taking into account embedded generation in the form of roof-top solar and other distributed generation. (f) **Based on the demand estimate furnished by the SLDCs, each RLDC shall prepare the regional demand estimate and submit to NLDC**. NLDC, based on regional demand estimate furnished by RLDCs, shall prepare national demand estimate. (g) Timeline for submission of demand estimate data by SLDCs to respective RLDC and RPC shall be as follows:	discharging of ESS cycle.

		TABLE 5: TIMELINE FOR DEMAND ESTIMATION **Daily demand estimation** **10:00 hours** of previous day **Weekly demand estimation** **First working** day of previous week **Monthly demand estimation** **Fifth day of** previous month **Yearly demand estimation** **31st August** of the previous year (h) **SLDCs, RLDCs and NLDC shall compute forecasting error for daily, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in future.** The computed forecasting errors shall be made available by SLDCs, RLDCs and NLDC on their respective websites.	
Chapter 7 Scheduling and Despatch Code			
6	Regulation (45) General Provisions, Sub regulation (6)	**Adherence to Schedule**: Each regional entity shall regulate its generation or demand or both, as the case may be, so as to adhere to schedule of net injection into or net drawal from the inter-State transmission system	MSEDCL is serving around 2.81 Crore consumers with sales of around 1.31 Lakh MUs. With such huge amount of power flow in the system, it is almost impossible to match projected day-ahead demand with real time demand. Hence, even if MSEDCL makes all possible efforts to adhere to the schedule, the forecasted demand is bound to have some amount of error when compared to actual demand. It is therefore submitted that the current

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			practice of **changing schedule for ISGS station in the 7th /8th time block onwards may be continued** so as to provide enough flexibility to DISCOMs to correct any deviations caused in forecasting with respect to real time data. This would also support DISCOMs in curtailing deviation charges to large extent.
7	Regulation (45) General Provisions, Sub regulation (7)	**Area Control Error:** The concerned Load Despatch Centre and other drawee regional entities shall keep their Area Control Error close to zero (0) by deploying reserves and automatic demand management scheme	It is observed that during most of time blocks in a day, there is surplus power available at intra-state generating station which is backed down to match Load-Generation as per Merit Order Desparch (MOD) stack. It is submitted that to keep area control error close to zero in real time, SLDC **should primarily make use of power available from back down stations as per MOD principle, followed by the reserves made available by the ancillary services providers.** Deployment of **ADMS (load shedding) shall always be the last resort**. Hence it is requested that ADMS may be implemented only when it is utmost necessary under a situation when the power flow is causing threat to the grid.
8	Regulation (46) Security Constrained Unit Commitment , Sub	The objective of Security Constrained Unit Commitment (SCUC) **is to commit a generating station or unit thereof, for maximization of reserves in the interest of grid security,** without altering the entitlements and schedule of	It is submitted that Technical Minimum(TM) of the generating station and Merit Order Despatch (MoD) shall work in synchronization for ensuring availability of reasonable power to

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	regulation (1)	the buyers of the said generating station in the day ahead time horizon	consumers. Some facts that are observed about ISGS schedule less than TM are as follows: Some buyers are scheduling power for short duration (mainly during evening peak hours when market prices are high) and for remaining time blocks they are keeping the schedule as "Full Surrendered". It is also noted that Power from ISGS stations is sometimes scheduled by DISCOMs only to sell it in RTM and get the benefit of higher price instead of using it for self-consumption. In such case other beneficiaries which are in need of power during evening peak are compelled to provide required TM schedule to the station so as to keep the unit on-bar and to avoid costly power purchase from other sources during evening peak. This could be minimized by keeping one unit on-bar and another in off-bar as it will be required to provide necessary TM schedule for one unit only. During evening peak the beneficiary can schedule off-Bar and URS power to meet its's requirement. But in real time this is not happening and the other buyers take undue commercial gain by scheduling power during high market price without supporting the station during off peak hours. This leads to increase in power purchase

			cost of one state who is giving continuous TM support, as compared to the other beneficiary of the stations who schedules power only when market prices are high without taking the burden of TM support. This SCUC mechanism cannot extend its support to station like "Solapur" which is having highest variable cost. Hence it is suggested that to have win-win situation if any beneficiary want to schedule power from CGS stations, then these beneficiary should be compelled to schedule at least 55% of its share for all time blocks during the day. It means that if any beneficiary reduced its scheduled from CGS to zero in any of the time blocks during the day, the scheduled for all the remaining blocks will be zero. In case of unexpected change in demand, buyer/beneficiary may be allowed to schedule between 0 and 55% with consent of RLDC, provided there is no issue of providing technical minimum to the generators. This will avoid undue benefit to one beneficiary at cost of another beneficiary
9	Regulation (46) Security Constrained Unit	The SCUC may be undertaken on **day ahead basis, in respect of the generating stations** or units thereof, for which tariffs are determined by the Commission under	To maintain flexibility to the buyer, **generators** having PPA with DISCOMs **shall not be allowed to bid its power in day-ahead**

	Commitment , Sub regulation (4)	section 62 of the Act, as per the following process: (a) By 1330 Hrs of D-1 day, 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turn down level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in power exchanges, received till 1300 Hrs of the D-1 day. (b) Beneficiaries of such stations, whose units are likely to be scheduled below minimum turndown level for some or all time blocks of the D day, shall be permitted to revise their requisitions from such stations by 1630 Hrs of D-1 day, in order to enable such units to be on bar. The revised requisition from the said generating stations, once confirmed by the beneficiaries by 1630 Hrs of D-1 day, shall be final and binding after 1630 Hrs of D-1 day and further reduction in drawal schedule shall not be allowed from such stations for such time blocks. (c) After 1630 Hrs, the NLDC in coordination with RLDCs shall prepare the final list of such generating units that are likely to go below their minimum turndown level and such generating units shall be stacked as per merit order, that is, in the order of the lowest variable charge to the highest variable charge. The generating units so identified shall be considered for undertaking SCUC. (d) If the NLDC in coordination with RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i)	**market without consent of buyer**. This would enable DISCOMs to schedule power from these generators if there is unexpected increase in demand. However, they can be allowed to bid in RTM market. Beneficiaries shall be allowed to revise schedule of ISGS station subject to Technical Minimum of that plant. **Any buyer shall be allowed to take responsibility of TM schedule of unit** (scheduling URS/Off-Bar power) provided other beneficiaries will not take undue advantage of market rates during evening peak. URS power available can be scheduled by the beneficiaries as per the current practice of **revising the schedule from 7th and 8th block onwards**. NLDC can use SRAS and TRAS by scheduling it from 4th time block

		extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security; (iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of clause 4 of this Regulation, so as to bring such units to their minimum turndown level, in order to maximize availability of on-bar units, by 1800 Hrs. of D-1 day and update the list on the respective RLDC website. (e) In order to maintain load generation balance consequent to scheduling of incremental generation as per sub-clause (d) of clause 4 of this Regulation, the NLDC in coordination with RLDCs, shall make commensurate reduction in generation from the on-bar generating station(s), subject to technical constraints, starting with the highest variable charge in the stack of generating stations maintained for the purpose of SCED in accordance with these regulations. (f) The generating station from which incremental energy has been scheduled as per sub-clause (d) of clause 4 of this Regulation shall be paid from the Deviation and Ancillary Services Pool Account, for the energy charge equivalent to the incremental energy scheduled, and the generating station from which reduction in generation has been directed as per sub-clause (e) of clause (4) of this Regulation shall pay back to the Deviation and Ancillary Services Pool Account, the energy charge equivalent to the decremental energy. (g) The URS power over and above the minimum turn	

		down level, available in the generating station or unit thereof, brought on-bar under clause 4(d) of this Regulation shall be deemed to be available for use as SRAS or TRAS or both in terms of the Ancillary Services Regulations. (h) UNIT SHUT DOWN (USD) (i) The generating stations or units thereof, identified by NLDC in co-ordination with RLDCs, as per Clause (4) (c) of Regulation 46 of these regulations, but not brought on bar under SCUC, shall have the option to operate at a level below the minimum turn down level or to go under Unit Shut Down (USD). (ii) In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD, by entering into a contract(s) covered under the Power Market Regulation or by arranging supply from any other generating station or unit thereof owned by such generating company subject to honoring of rights of the original beneficiaries of the said generating station or unit thereof from which supply is arranged	
10	Regulation (47) Procedure For Scheduling and Despatch for Inter State Transactions , Sub regulation(1)	(i) The generating station whose tariff is determined under Section 62 of the Act, may sell its un requisitioned surplus as available at 10 AM in the day ahead market.	The proposed clause provides that the generating station whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus (URS) as available at 10 AM in the Day Ahead Market of Power Exchanges.

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11	Regulation (47) Procedure For Scheduling and Despatch for Inter State Transactions , Sub regulation(4)	**Revision of schedules on request of regional entities:** (a) SLDCs, regional entity generating stations, regional entity ESSs, beneficiaries, buyers or cross-border entities may revise their schedules under GNA as per clause (b) and clause (c) of this Regulation in accordance with their respective contracts. Provided that **scheduled transactions under T-GNA once scheduled cannot be revised** other than in case of forced outage as per clause (7) of Regulation 47 of these regulations. (b) The request for revision of scheduled transaction for 'D' day, shall be allowed to be made in any time block **starting 2 PM on 'D-1'** day subject to the following: (i) In respect of a generating stations whose tariff is determined under **Section 62 of the Act, upward revision of schedule shall be allowed starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un-requisitioned surplus after finalization of schedules under day ahead market.** (ii) In respect of a generating stations whose tariff is not determined under Section 62 of the Act, revision of schedule shall be in terms of provisions of the respective contracts between the generating stations and beneficiaries or buyers. (c) Based on the request for revision in schedule made as per sub-clauses (a) and (b) of Clause 4 of this Regulation, any revision in schedule made in odd time blocks shall become effective from 7th	In the existing ISGC, a similar provision for sale of URS power is available subject to the consent of the beneficiary. The proposed proviso is doing away with the requirement of the consent of the beneficiary which inter-alia means that the Discoms/Beneficiaries will not be able to recall such power if such power has been sold in the DAM by the Generators. Further, the provision does not envisage any waiver of fixed charge liability. In such case, the beneficiary will not be able to avail the benefit of the Generation if it doesn't schedule the power within the stipulated time, despite the payment of fixed charges by the beneficiary. In addition to above following demerits are foreseen on account of above provision: 1. **Management of variable RE in the Grid**: With the high penetration of RE in states like Maharashtra, variability in supply is inevitable. Therefore, it is essential to have on-bar capacity with the Discoms to serve its demand. In case if URS power is not available to the Discoms, the Discoms will get exposed to market risk and may not meet its demand which in turn may either lead to load shedding or increased power purchase cost. This

		time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one. (d) While finalizing the drawal and despatch schedules, in case any congestion is foreseen in the inter-State transmission system or technical constraints of a generating station, the concerned RLDC shall moderate the schedules as required, under intimation to the concerned regional entities	ultimately results in additional burden to its consumers. 2. **Management of variation in Demand**: The demands of the Discoms vary with the seasons and time of day requirements. With the proposed clause, the Discoms will have to depend on the Real Time Market (RTM) to meet its demand variation during the day. At times it is observed that there isn't sufficient quantum of volume available in RTM. Under such conditions, the Discoms may get exposed to volume risk, leading to load shedding. 3. **Optimisation of Power Purchase Cost**: The proposed clause provides for sale of URS power without consent of the beneficiary and it also proposes in Regulation 47(4)(b)(i) that only upward revision of schedules will be allowed for Generators u/s 62 after 2 p.m. As per the existing arrangement, the Discoms are able to optimize their power purchase cost by replacing their costlier plant with the purchase from the market. Discoms place bid quantum equivalent to the Declared capacity of costlier plants and if market price is less than the variable cost, such generator is asked to back down by Discom. With the provision of only upward revision, it is not possible for such cost optimisation through market conditions. Discom will have to necessarily schedule the

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			costly power from their contracted Generators to avoid any volume risk associated with the market. This will take away the opportunity to reduce power purchase cost through participation in the market. 4. **Breach of PPA conditions**: The Generator and Discoms are bound by the PPA entered into between them and the tariff is determined by the Hon'ble Commission u/s 62. The PPA provides rights to the Discom to schedule power subject to the regulations of the Hon'ble Commission. The tariff is being bifurcated into two parts i.e. fixed charges and energy charges. The fixed charge liability arises only based on the availability declared by the generating station at the disposal of the beneficiary. However, with the proposal of sale of URS power, the Generator will not be available to declare its availability at the disposal of the beneficiary. Hence, the proposed clause not only contravenes the terms and conditions of the PPA, but also the basic premise of the determination and levy of the fixed charges by generators.
			In view of the above, it is requested that the URS power should be made available to the Discoms to meet its contingency requirements and if at all such power is to be sold by

			Generators in the market, such sale should be subject to consent of the Discoms. Further both upward and downward revisions shall be allowed as per present practice i.e. 7th /8th time block and Generators shall be allowed to sell URS power in RTM market with sharing of gains with the beneficiaries