ENERGY ANALYTICS LAB
Department of Management Sciences
Indian Institute of Technology Kanpur

ISSN: 2583-2409 (O)
Volume 6 | Issue 2
October 2023

Power Chronicle

Editorial

The proposed implementation framework for SCUC lays down a framework for system constitutions especially the generators and the beneficiaries. In doing so, the procedure effectively moves the gate closure for the beneficiaries (read discoms) for a greater proportion of the demand to 8:00 AM on a day ahead basis while allowing for flexibility to recall part of the capacity made available due to avoided shutdown of a marginal unit. Given the higher cost of such units, such a flexibility offers limited economic benefit to the beneficiaries, subject to market conditions. Given the increasing share for VRE sources, it is suggested that 90-95% of the unscheduled DC of the generating station may be allowed for participation in the DAM-Energy market by the respective generators, giving up to 5-10% room for the beneficiaries to address uncertainties associated with VRE. A pilot for SCUC may be implemented for a period of 3 months to ensure that the system constituents can ensure timely availability of information, develop scheduling strategies and make a seamless transition. The existing framework for arranging alternate supply due to a generator undergoing reserve shutdown (RSD) falls on the beneficiaries. This completely passes on the risk to the latter. The SCUC propose to shift this risk completely to the generators. SCUC provides a system wide service, thus associated risks from RSD could be shared amongst the generator, the beneficiaries and the system operator causer pay principle (with some amount of risk sharing across the three). Demand response (DR) plays very important role in ensuring system balance. The prevailing approach, in general, has not been able to give adequate attention to DR, both at planning as well as operational level including the SCUC proposal. Development of an ecosystem DR across states is an urgent need of the hour. Regulatory and policy framework for ensuring that such programs can contribute not only to address market volatility but also provide required services to ensure secure operation of power system. Power Exchanges (PXs) have played a crucial role in expanding and deepening the competitive segment of the Indian electricity market. The country has three PXs, one of them has excelled in attracting a larger share of the key market segment while the others have also discovered a niche segment for themselves. The competitive advantage of the competing PXs has been driven by their business and operational practices. The CERC staff paper suggesting market coupling is based on the theoretical foundations that coupling will result in better outcome. However, in practice this would also drive down innovation and more so the competitive advantage earned by the respective PXs in their dominant segments. The PXs driven market is coupled across market areas, by design. However, coupling of PXs may bring its own implementation challenges especially those on account of clearing and settlement. The long-run may witness pressure to water down the eligibility requirements for 'bid gathering agencies', who would deliver them to a unified market platform. Risk of non-serious players entering the segment and damaging the faith of market participants would weigh on the minds of regulators as well as policymakers.

Anoop Singh
Founder & Coordinator, Energy Analytics Lab

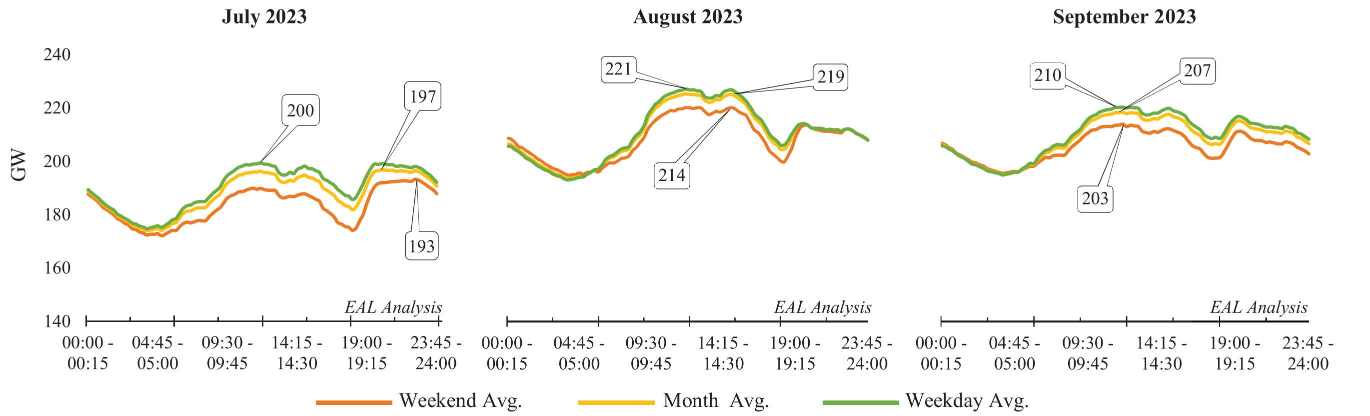
Access Online
eal.iitk.ac.in

☞ Register at **eal.iitk.ac.in** to access data and resources

Publisher: Energy Analytics Lab (EAL)
Department of Management Sciences
Indian Institute of Technology Kanpur, Kanpur – 208016 (India)

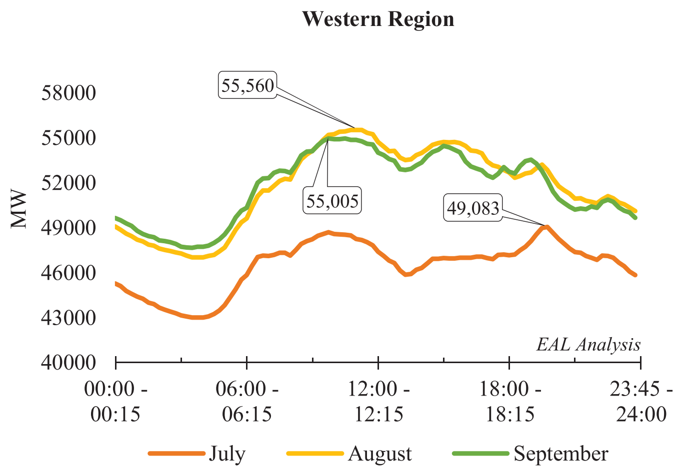
Power System Overview & Analysis

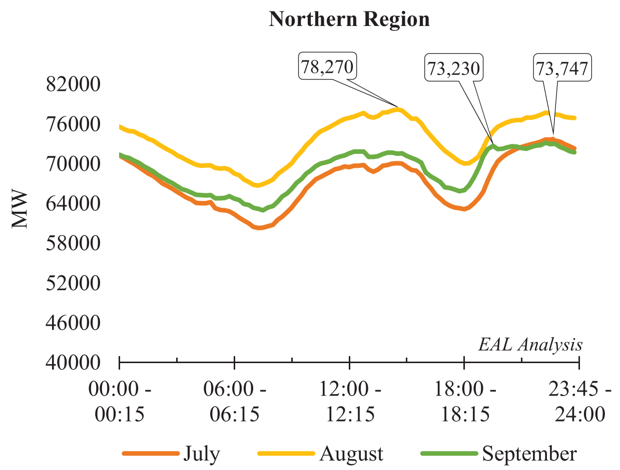
All India Demand Met Profile

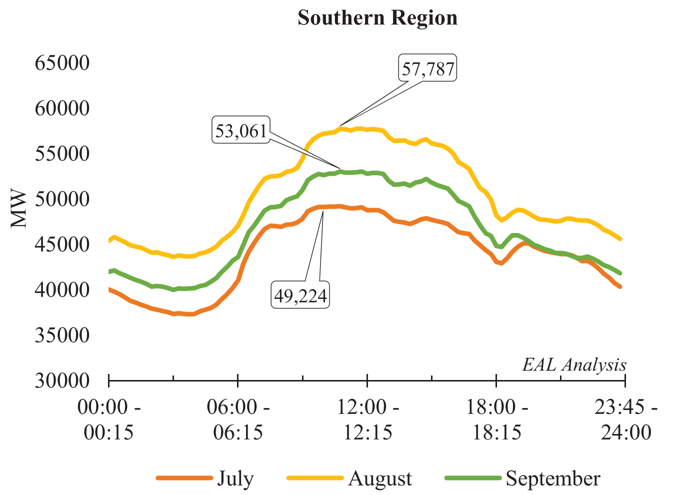


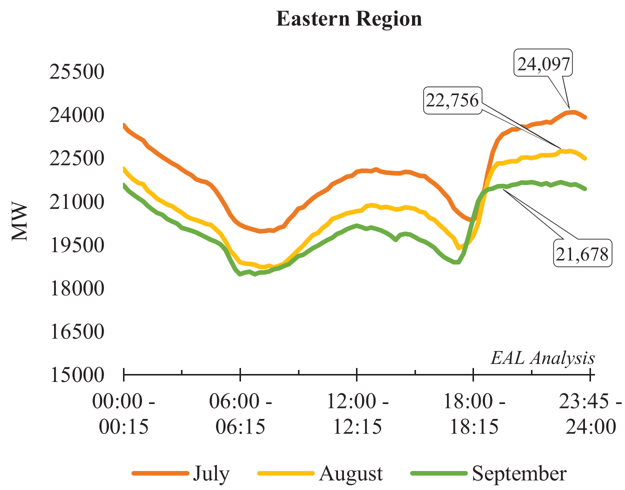
From July to September quarter, all India peak demand reached 239.98 GW (12:15 - 12:30) on 1st September, 2023, about 18.50% higher than the previous year's peak demand recorded at 202.5 GW (11:45 - 12:00) on 10th September, 2022, during the same quarter.

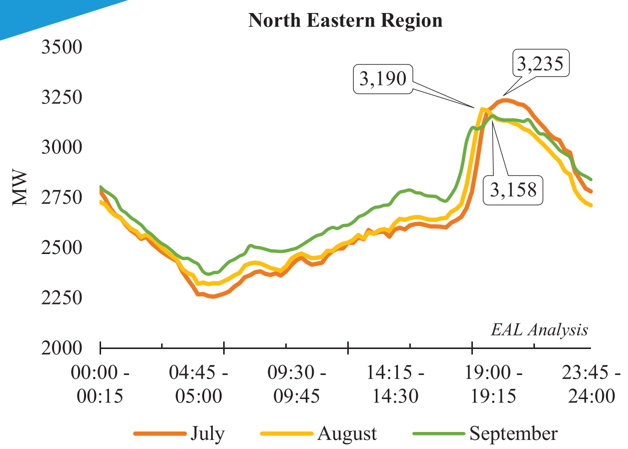
Region-wise Demand Met Profile







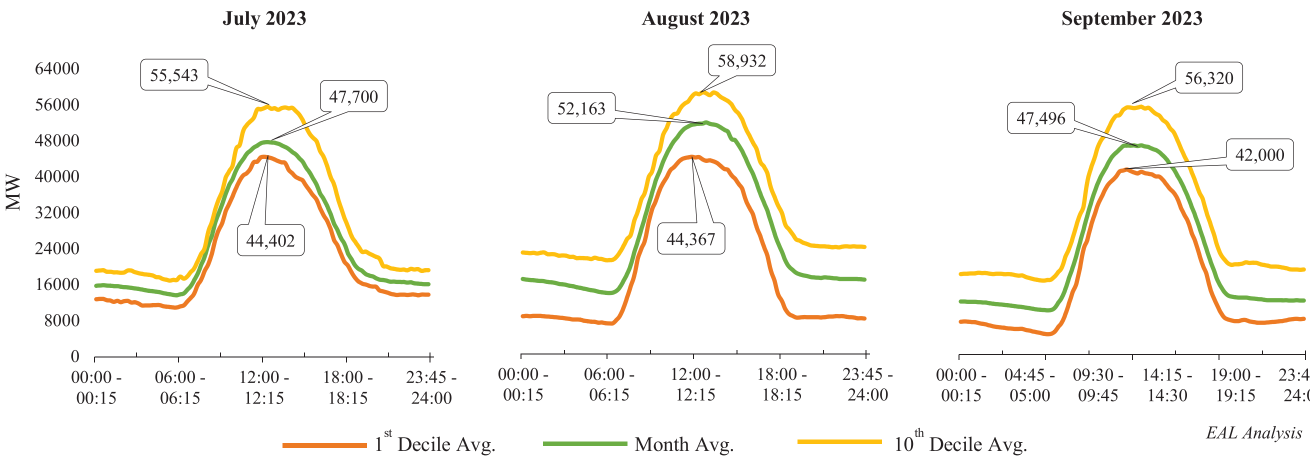




- Significant increase in demand can be observed for North Eastern region from 18:00 to 21:00 hrs & Southern region from 10:00 to 16:00 hrs in all the three months.
- Gradual decrease in demand can be observed for Northern & Eastern regions from 04:00 to 08:30 & 15:00 to 17:45 hrs in all the three months respectively.
- Average demand is found to be higher for Northern region as compared to the other regions in the month of August.

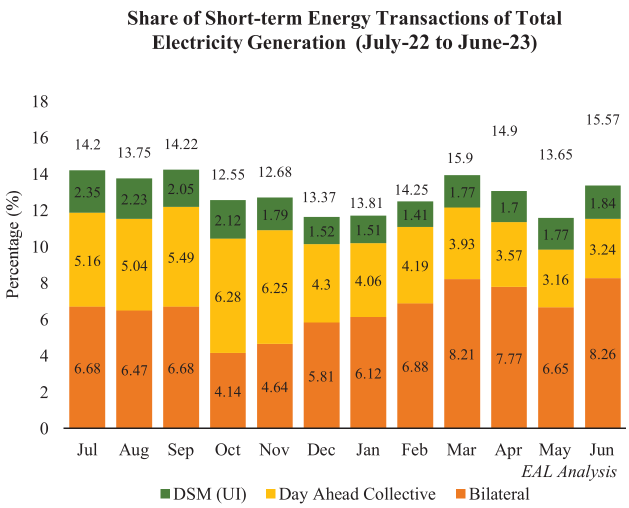
Demand and generation profiles at National, Regional and State-level can be accessed on EAL's web portal.

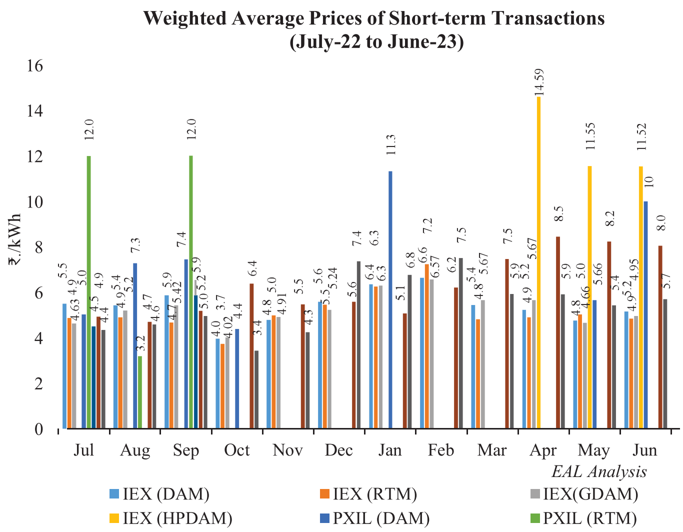
All India Renewable Energy (RE) Generation Profile



All India peak RE generation reached 58.95 GW (12:45 - 13:00) on 2nd August, 2023, about 22.50% higher than the previous year's peak of 48.12 GW (13:15 - 13:30) on 23rd August, 2022.

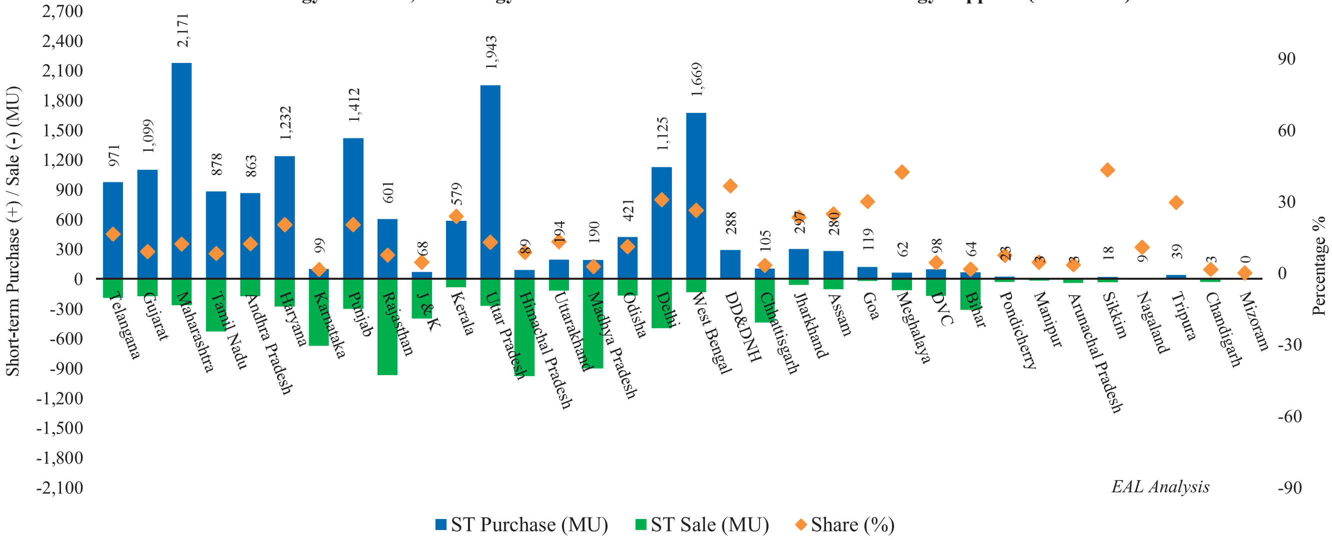
Short-term Energy Transactions





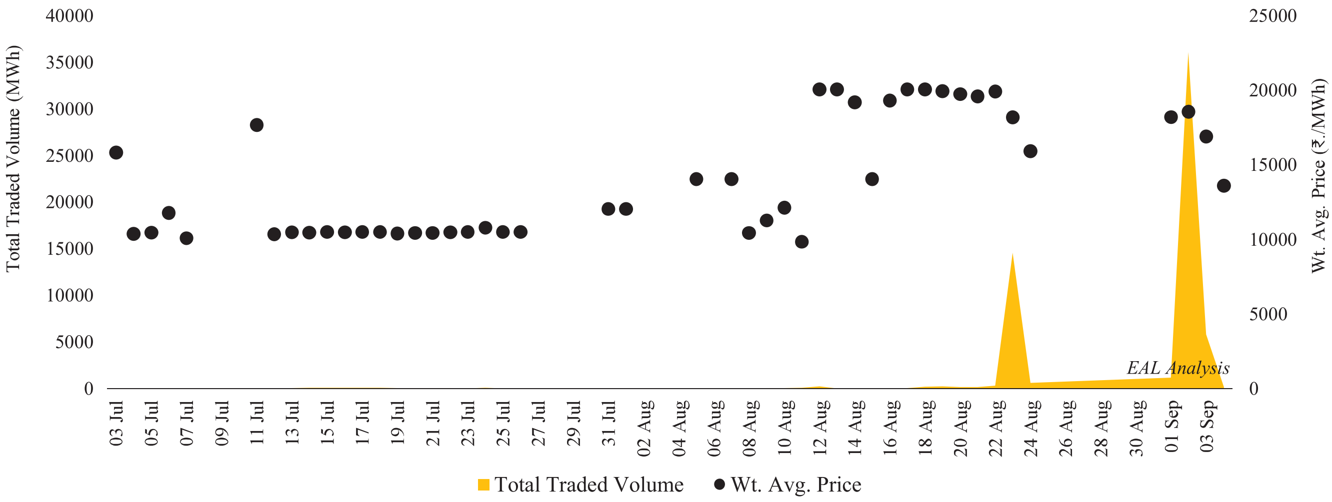
Monthly Short-term (ST) Purchase and Sale Quantum across States

ST Energy Purchase, ST Energy Sale and share of ST Purchase in Total Energy Supplied (June 2023)



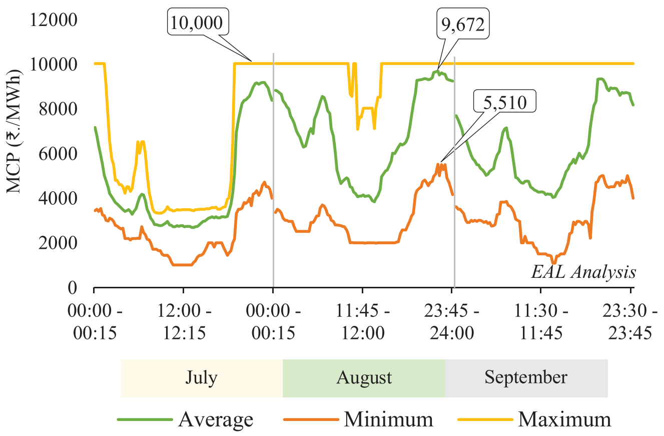
Power Market Overview & Analysis

HP-DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

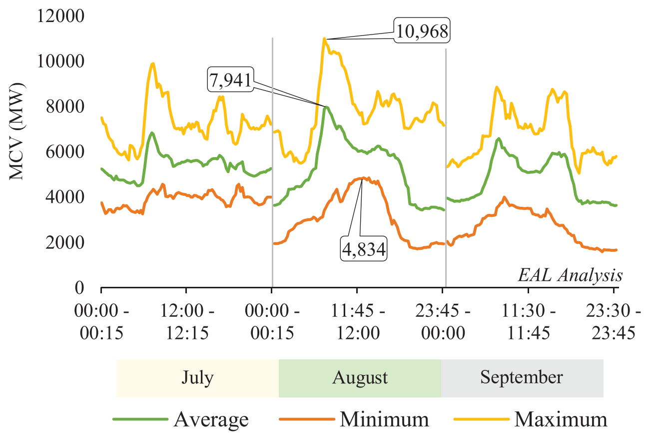


DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

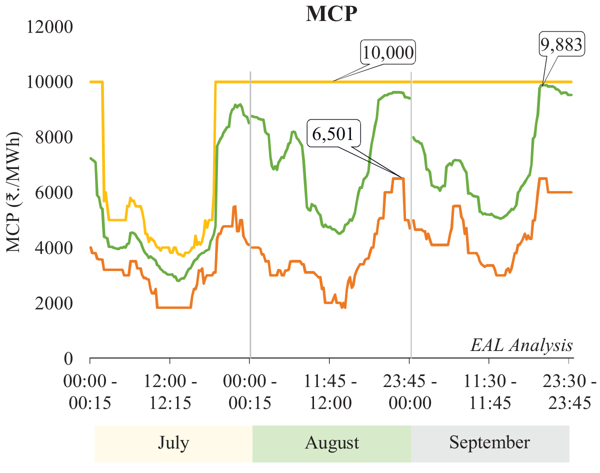
DAM Monthly Average, Maximum & Minimum MCP

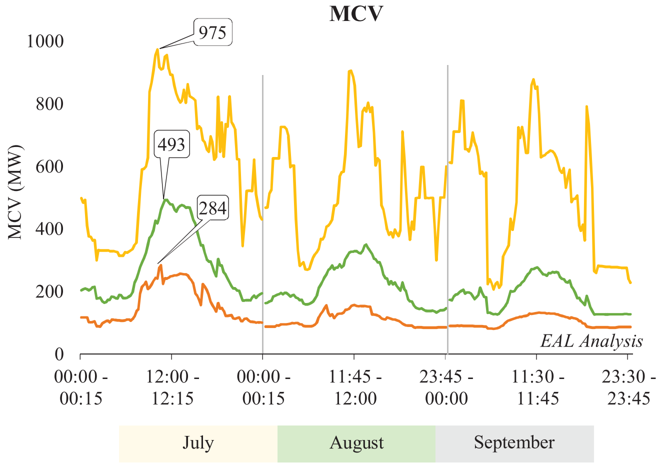


DAM Monthly Average, Maximum & Minimum MCV

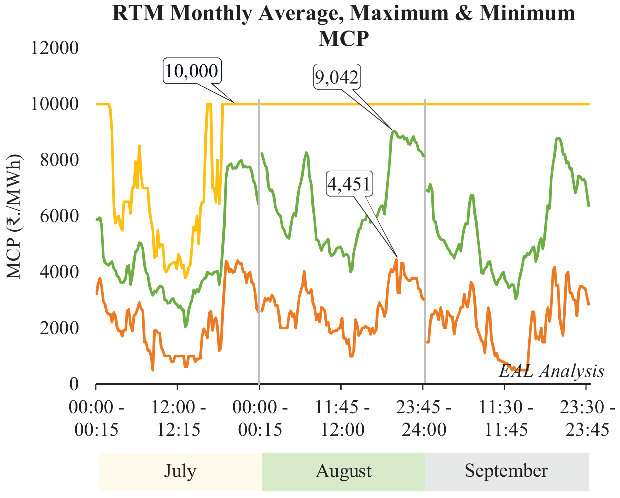


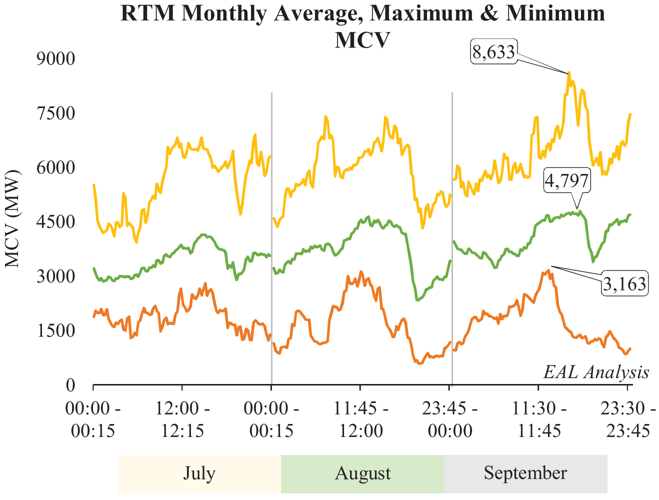
G-DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)



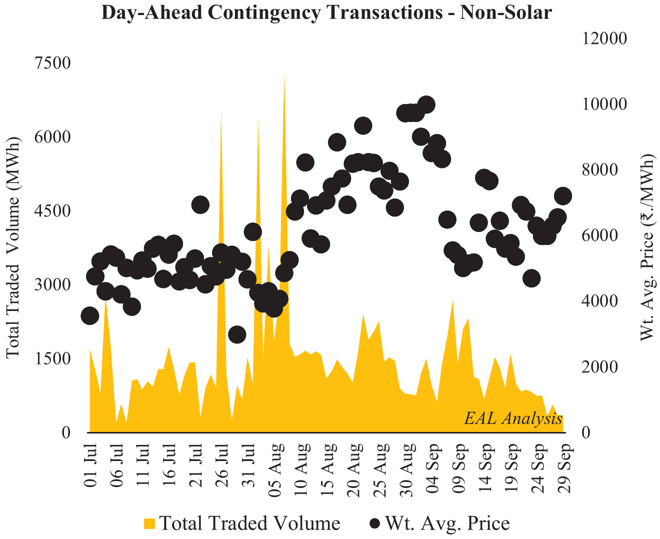


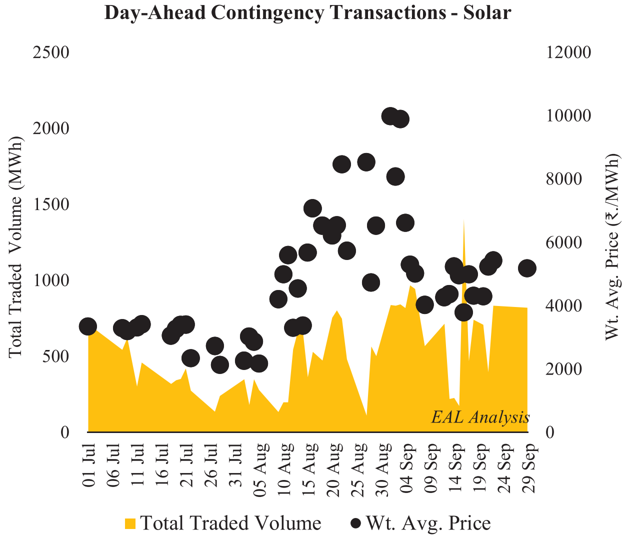
RTM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)





Green Term-Ahead Market (G-TAM)

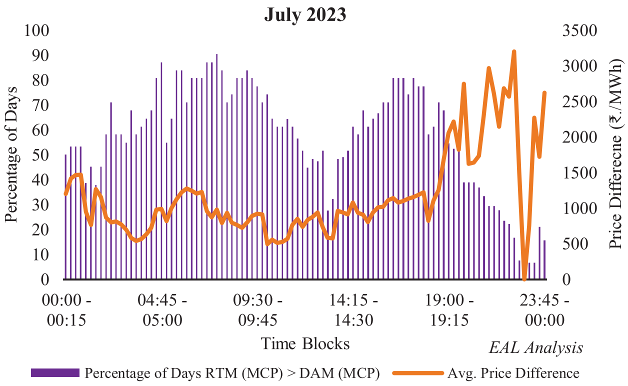


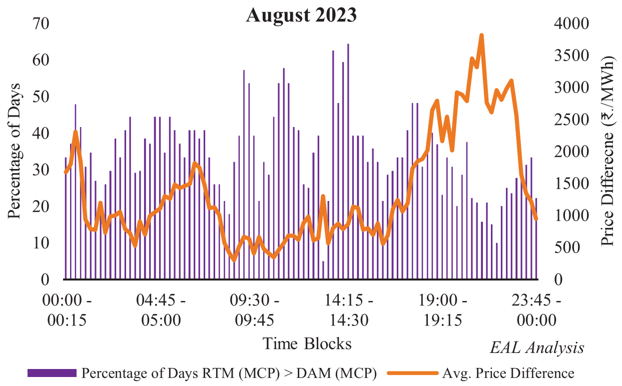


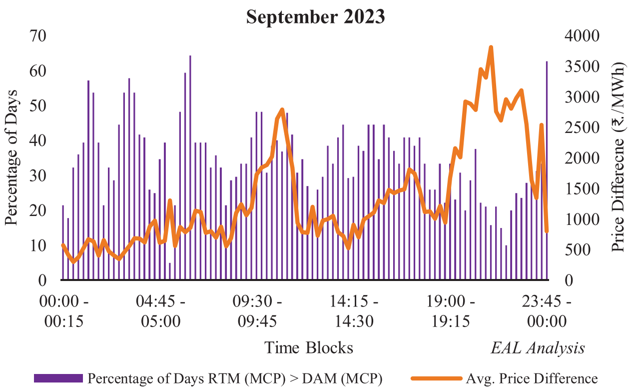
ENERGY ANALYTICS LAB

For more information Click here

Price Difference b/w RTM vs DAM



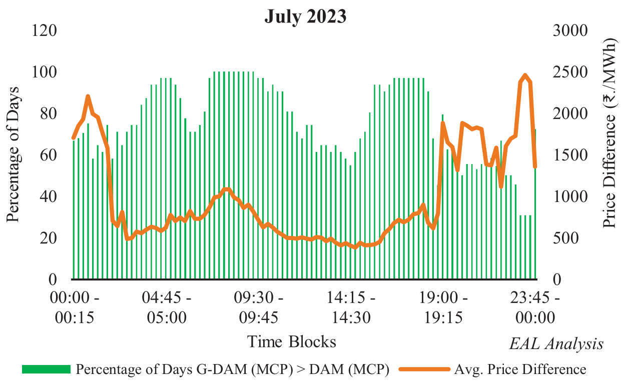


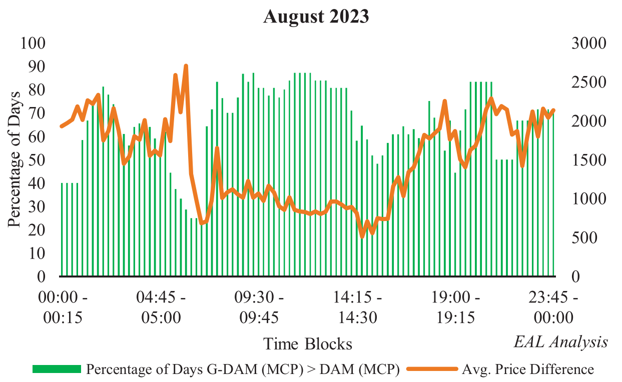


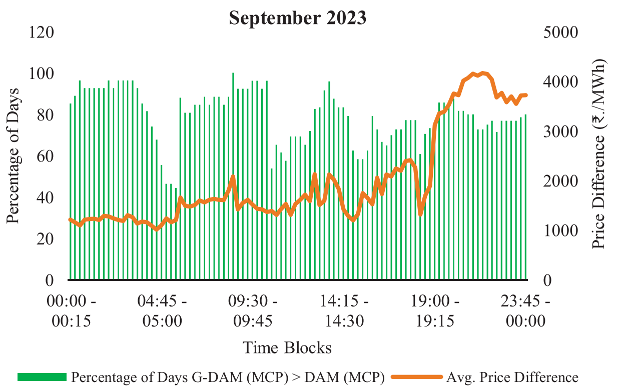
EAL Analysis

- The analysis is based on comparison between the average price difference of RTM and DAM, when MCP of RTM is greater than DAM for the second quarter of year 2023-24.
- The graph shows the percentage of days, price for RTM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- It has been observed that the price difference is more during non-solar hours.
- The average price difference between RTM and DAM is Rs. 1.28/ kWh for the quarter.

Price Difference b/w G-DAM & DAM







EAL Analysis

- The analysis is based on comparison between the average price difference of G-DAM & DAM, when MCP of G-DAM is greater than DAM for the second quarter of year 2023- 24.
- The graph shows the percentage of days, price for G-DAM is greater than DAM on the primary axis & the average price between the two on secondary axis.
- It has been observed that the price difference is higher during morning hours for the month of July & August and during non-solar hours in all three months.
- The average price difference between G-DAM & DAM is observed to be Rs. 1.48/ kWh for the quarter.

Energy Analytics Lab

For more information Click here

Regulatory & Policy Perspective

Grid-India (Detailed Procedures for Security Constrained Unit Commitment (SCUC), Unit Shut Down (USD), and Security Constrained Economic Despatch (SCED) at Regional Level), 2023 [Draft]

Grid-India notified "Detailed Procedures for Security Constrained Unit Commitment (SCUC), Unit Shut Down (USD), and Security Constrained Economic Despatch (SCED) at Regional Level" on 07th September, 2023. The key highlights of the draft are mentioned below:

- This document aims to clarify the roles and duties of different parties involved and provide a framework for operation of SCUC, USD and SCED. SCUC focuses on boosting reserves for grid security, while SCED strives to optimize electricity generation to achieve National Merit Order after gate-closure for RTM.
- The procedure is applicable to thermal generating stations within regional entities whose tariff is determined u/s 62 of the EA, 2003 and also to the other regional thermal generating stations willing to participate in SCUC/ SCED. Thermal generating stations opting for SCUC are mandated to participate in SCED as well.
- The procedure defines the roles of NLDC, RLDC and RPC w.r.t the SCUC, SCED, USD and the settlement/ compensation mechanisms for the generators.
- The list of generating stations along with their synchronization time and date, need to be operational in the next two days will be published two days in advance at 10:00 hrs. Also, the list of units required to operate on the following day under different conditions (hot, warm, and cold) will be published on the NLDC website daily at 15:00 hrs, including the date and time.
- The following figure shows the timelines for SCUC.

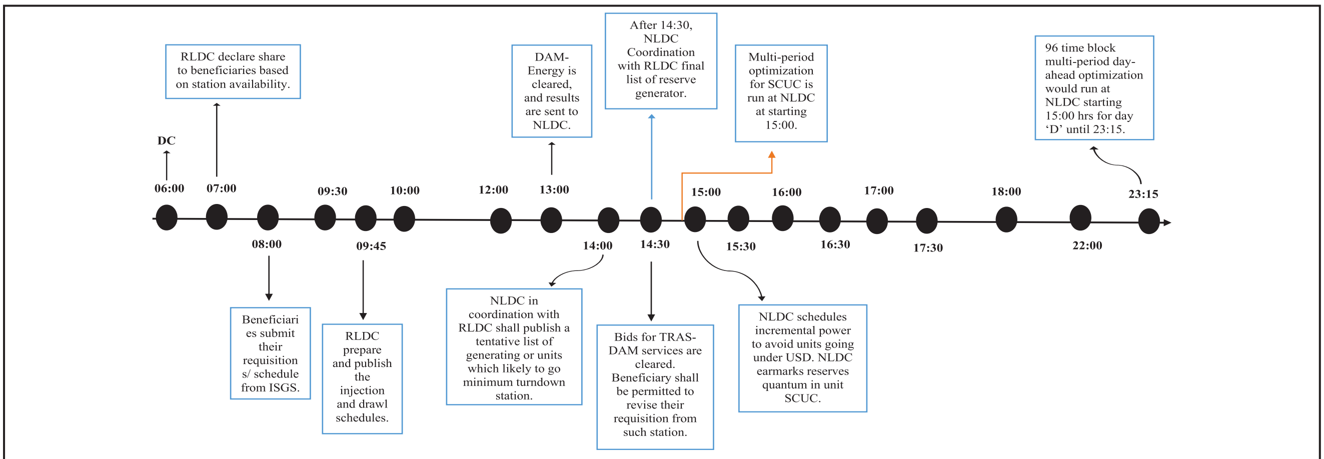


Figure 1: Timeline for SCUC

- The beneficiaries can revise their schedule for the units scheduled below the turndown level by 14:30 hrs. of D- 1 and if not revised or not scheduled under SCUC, the units can either operate below the minimum turndown level or undergo USD.
- NLDC indicates the reserve quantum earmarked in each unit brought on bar under SCUC by 15:00 hrs to the scheduling system. This quantum of power identified as reserves is not available for scheduling by beneficiaries or for sale by the generating station through the energy market. The document also mentions the running of a 96 time block multi-period day-ahead optimization at NLDC for day 'D' until 23:15 hrs.
- The draft procedure outlines the compensation process for SCED generators experiencing Heat Rate Degradation (HRD). NLDC will release a monthly "National Statement of Compensation" due to Part Load Operation on account of SCED based on SCED statement of respective RPC. The SCED generator will receive compensation for HRD within 7 working days from the National Pool Account (of SCED) based on the monthly statement.

EAL Opinion

- **Economics of Security Constrained Unit Commitment (SCUC):** The preliminary results of an ongoing study at Energy Analytics Lab (EAL), IIT Kanpur show that additional saving in power procurement cost may emerge with the adoption of for SCUC. The study used three month's data from five states in the northern region and estimated overall costs under alternate market arrangements.

- **Master Repository of NOAR:** It is suggested that the NOAR may share the data of variable charge/ compensation charge for respective plants participating in SRAS, TRAS, SCUC & SCED and publish it in the public domain (on its scheduling/ reporting portal). This will enable the discoms to dynamically optimize their own schedule as well, specifically the schedule of their own generating stations.

- **Effective Gate Closure for Discoms:** As per Clause 6.2 and Clause 6.3 of the draft procedure, *"Regional Load Despatch Centres (RLDCs) would prepare the entitlements and declare the share of each beneficiary on D-1 [by 07:00 hrs]. **Beneficiaries shall submit their requisitions/ schedules from ISGS on D-1 [by 08:00 hrs]."*** (emphasis added)

  *"Based on the station availability and the schedules submitted by beneficiaries/procurers, **RLDCs shall prepare and publish the injection and drawl schedules [by 09:45 hrs]. The power station then can participate in Day-ahead Energy Market (DAM-Energy) and/or Day-ahead TRAS Market (DAM-TRAS).** The DAM-Energy shall be cleared [by 13:00 hrs], and Power Exchanges would convey DAM results to NLDC after clearing of market"* (emphasis added).

  The above provision effectively advances "gate closure" for the beneficiaries to the extent of the capacity that may be cleared in the DAM-Energy market[1]. Given the increasing share of renewables across states, there is greater uncertainty for the beneficiaries to take informed decision on schedule about 20+ hours in advance. It is suggested that 90% of the unscheduled declared capacity of the generating station may be allowed for participation in the DAM-Energy market by the respective generators. Beneficiaries may be given a leeway for rest of the capacity (10% of the residual capacity) till RTM-Energy. These limits may be periodically revisited, based on experience of the stakeholders.

- **Pilot for SCUC:** Since SCUC is being implemented first time, it is suggested that a pilot may be introduced initially in order to understand the practical implications and challenges thereof. Based on the experience over a period of, say, 3 months the final procedure can be frozen after necessary fine tuning.

- **Availability of Generator in Shut down condition to be on-bar:** Since signal for restart (hot/ warm/ cold) and shutdown may be given anytime within a block (i.e. not necessary at the interchange of the blocks), the relevant duration should be measured from the expiry of the current block in which the instruction to the generator is given by the load despatch centre. It is suggested that the following clarification may be **added** in the Clause 6.13 of the draft procedure *"The unit/ station should be available on, after the respective duration of revival (4 hrs. 8 hrs. or 12 hrs.) according to the type of start-up (hot, warm or cold), counted from the end of the block in which the respective instruction is given to the generator."*

- **Reduced minimum shutdown duration for a generator:** The Clause 6.14.4, *"A generator can submit a lower time limit than the above to NLDC/RLDCs, and the same would be considered."* need further clarification. Would such an exception needs to be specified each day or it needs to be specified periodically by a generator, till it is updated by the generator.

  Also, it may be clarified whether the above Clause is applicable only for minimum shutdown time or it will be applicable for the minimum dispatch duration as well.

- **Reserve requirement calculated on the basis of supply availability?** Clause 6.8 of the proposed draft states that *".. The following shall be factored while calculating the TRAS Reserve Requirement "Z", for the purpose of SCUC for the next day.*

  6.8.1 The reserves created due to action of SCUC in the previous 7 days
  6.8.2 The reserves anticipated to be available in Section 62 plants
  6.8.3 Advance reserves procured, and reserve position intimated by the states.

[1] Beneficiaries can revise the schedule upwards for those plants which would have a schedule lower than minimum technical turndown level.

ENERGY ANALYTICS LAB

Thus, the reserve requirement for the next day 'considers' the availability of the reserve supply. **A method, independent of the supply, to ascertain reserve requirement for the next day should be developed and elaborated in the document.**

- **Change in the overall economics of the power procurement:** As per Clause 6.17 of the proposed draft, *"Typically, the net sum of generation schedules under SCUC head would be zero, as only reserves are being created through SCUC and extra energy is not being scheduled."* As illustrated in the following Figure 2, two generators committed under SCUC (say, G1 = 100 MW and G2 = 100 MW) have same capacity but different variable costs (say, Rs. 4.00/ kWh and Rs.5.00/ kWh respectively). Generator G1 received 100% schedule (100 MW) from its respective beneficiary while G2 received 40% schedule (40 MW) i.e. below minimum turndown level. In order to create the reserves and prevent G2 to go under shutdown, the NLDC increased its schedule up to 55% under SCUC-up (55 MW) and reduced the schedule of G1 to 85% under SCUC-down (85 MW). Thus, the overall generation schedule remained equivalent to the original schedule (140 MW). While cost of power procurement plant will **increase the overall system cost for the current blocks in D day.** The incremental cost of the same would be met through the pool account.

  Due to minimum up/ down time constraints, the high-cost generator which was revived, would be treated as 'must run' plant (by the system operator) for the minimum number of up/ down time hours that may spill over to the next day. Are these plants to be treated as 'must run' by the beneficiaries while preparing schedule for the 'constrained' hours piling over to the next day? If so, the power procurement cost for the beneficiaries would effectively increase for the next day (D+1).

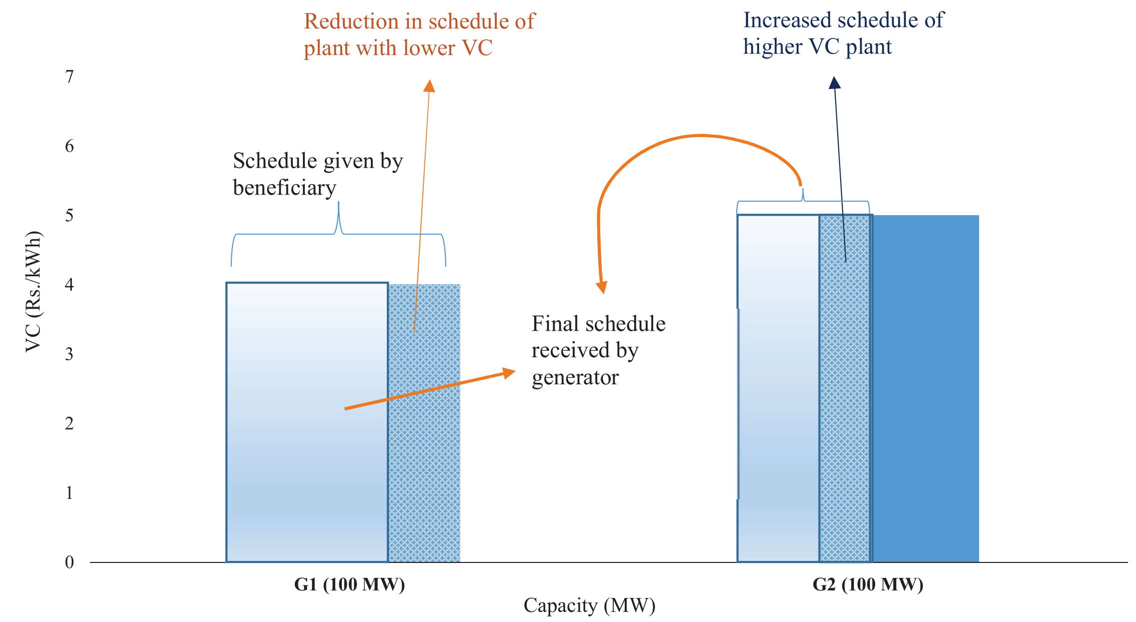


Figure 2: Increased generation costs to maintain reserves under SCUC

- **Scheduling the remaining capacity of the generator which is given the increased schedule under SCUC:** The draft procedure does not explicitly explain the system operation in case two generators having different variable costs which have received the schedules from respective beneficiaries below their respective minimum turndown level. It may be further clarified that when two generators have received schedules below their respective minimum turndown level, one of the unit having higher VC may be allowed to go under shutdown and the schedule of the generating station/ unit having lower VC may be increased under SCUC-up. For e.g. consider three generators G1, G2 and G3 having equal capacities of 100 MW and different variable costs, Rs. 4.00/ kWh, Rs. 5.00/ kWh and Rs. 6.00/ kWh and the schedules to these generators by their respective beneficiaries are 100 MW, 40 MW and 30 MW respectively. The minimum turndown level is 55% of their capacity. Thus, the schedule of only G2 may be revised to 40 MW + 30 MW (total 70 MW) under SCUC-up to bring it on-bar and generator G3 may be allowed to go under shutdown thus increasing the overall economic surplus while the remaining 30 MW capacity available on-bar from generator G2.

Obligation of the generating station to arrange alternate supply for fulfilling the demand of the beneficiary?

Clause 7.2 of the proposed draft states that *"In case a generating station opts to go under unit shut down (USD), the generating company owning such generating station 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 [i.e., before 15:30 hrs.], by arranging supply either*
7.2.1 by entering into a contract(s); or
7.2.2 by arranging supply from any other generating station or unit thereof owned by such generating company; or
7.2.3 rely on SCED for arranging the schedule 30 minutes before dispatch."

As per the current methodology adopted for the generator to go under reserve shutdown (RSD), a generator is not obligated to arrange for the alternate supply (as per the CERC order[2] dated 05th May, 2017, in the matter of 'Approval of the detailed procedure for taking unit(s) under Reserve Shut Down and Mechanism for Compensation for Degradation of Heat Rate, Aux. Consumption and Secondary Fuel Consumption, due to Part Load Operation and Multiple Start/ Stop of Units').

Since the generator declared the capacity (DC) for the respective time blocks, it was available to provide the energy with generation above the technical minimum. **The obligation of the generators opting to go under unit shutdown to supply the power to the beneficiary may be reviewed. The resultant risk should thus be shared between the generator and the beneficiary. It is highlighted that under the prevailing procedure, all the risk was on account of the beneficiary, which was also not justified. The procedure may reallocate the risk so that it shared by the generator, the NDLC (pool account) and the beneficiary (as explained below).**

It is to be noted that it is likely that due to RSD for a particular generation unit, other generating units may receive higher schedule thus partially fulfilling the gap on account of the RSD. The remainder gap remains the concern for the system operator. Furthermore, the generator may not be left with adequate platform for seeking the compensatory capacity, except the Day Ahead Contingency (DAC) or the Intra-day Contingency, both of which often have low liquidity and, thus may not provide sufficient opportunity for the generator undergoing RSD for the alternate procurement. In case NLDC/ RLDC has a spinning reserve above the minimum reserve quantum earmarked for each unit, the remainder capacity may be scheduled from the same. Since the generators available under spinning reserves are likely to have lower energy charge rate (ECR) than the one undergoing RSD, there would not be any additional incremental cost to the system. The capacity so scheduled from the spinning reserve and that scheduled earlier from the other plants under operation, would thus make good any gap in schedule for the beneficiaries. The beneficiary would pay as per ECR of the plant undergoing RSD, while actual energy would be supplied by a plant of lower ECR. The saving on this account should recouped into the pool account. This would also provide correct economic signals to the generator as well as the beneficiary. A generator may still be given an option to arrange the alternate supply (at lower ECR), as feasible within the available timeline. Furthermore, clarifications are required for the following points w.r.t Clause 7.2 –

a. **In case, the generating station does not have/ own any other units -** The final schedule to the generator will be received after 14:30 hrs., when all the day-ahead clearings have been completed and no further market contract option is available for the generator (except RTM and Day-Ahead Contingency, with no assurance of its bid getting cleared) opting to go under unit shutdown due to schedule below minimum turndown level.

b. **Unavailability of information of reserves available under SCED to the generating stations -** The generating station does not have any visibility of the resources available under SCED as it is run post RTM clearing and 30 minutes prior to dispatch and the required resources may not be available under SCED as already mentioned in draft Clause 8.5.3, which states that *" Note that there is no guarantee that SCED can provide the incremental schedule to meet the minimum turn down level, and hence this feature may be used as last resort to accommodate small (say, 5 MW, 10 MW, etc.) difference with respect to the zero MW level."* Thus, there is no assurance of the supply availability to the generator whether the alternate supply can be made available. Thus, it is suggested that the available resource optimization may be undertaken by the NLDC at 14:30 hrs. under SCUC, post finalisation of the schedule of the generating stations.

[2] CERC order in the matter of Approval of the detailed procedure for taking unit(s) under Reserve Shut Down and Mechanism for Compensation for Degradation of Heat Rate, Aux Compensation and Secondary Fuel Consumption, due to Part Load Operation and Multiple Start/Stop of Units. https://cercind.gov.in/2017/regulation/SOR132.pdf

c. **<u>Provisions if the generator is unable to provide the required supply to the beneficiary -</u>** While, we suggest alternate approach regarding the alternate supply, we note that the draft procedure, while mandating a generator (undergoing RSD) to secure alternative supply, does not mention the consequence if such a generator is unable to provide alternative supply to the beneficiary. In its absence, this provision would remain ineffective, if implemented.

Further it is suggested that if the generator opts to go under shutdown due to schedule below minimum turndown level in a few blocks, NLDC/ RLDC may provide for the energy to the beneficiary through SCUC for the time blocks when the schedule is below the minimum turndown level **<u>plus the minimum down time</u>** of the generator.

- **Increase in overall amount of compensation towards part load:** The draft Clause 9.9 states *"Compensation due to Part Load Operation due to SCUC to SCUC generator shall be paid from their respective regional 'Deviation and Ancillary Service Pool Account'.*

  Due to SCUC-up and SCUC-down (and increase in RE integration), as more units will be on-bar and running at their respective minimum turndown level or at part load (lesser than their respective declared capacity), the overall compensation on account of part load operation for such units will increase, thus leading to overall increased power purchase cost for the beneficiaries.

- **Amount towards part load compensation received by generator should be credited to the ancillary services pool account:** Post SCUC, and due to RSD of some of the generating units, schedule of some of the generating units may be above the threshold and thus should receive part load compensation only as per schedule post SCUC.

- **Demand response to be considered for SCUC:** The proposed draft considers the available generation capacity while calculating the SCUC for day-ahead and three days in advance. The demand response program, being always available on-bar, may provide for the SCUC-up requirement of the system and may even have a faster response time as compared to bringing a generating unit/ station on-bar or increasing the schedule of a generator. Hence, it is suggested that the demand response should become an inherent part of the overall SCUC procedure.

- **Consideration of day-ahead SCED:** The draft Clause 10.1, *" The incremental/ decremental day-ahead SCED schedules shall be maintained under a separate head in the scheduling system,"* creates an ambiguity as the procedure discussed prior to this Clause considers only the SCED scheduled post clearing of RTM and only mentioned in the above Clause 10.1. It is suggested that the procedure for day-ahead SCED may be included/ described for the generating stations and the accounting and settlement under SCED may be clarified considering the same.

- **Mechanism for sharing of SCED benefits:** As per the Detailed Feedback Report on Expanded Pilot for SCED March 2021[3], the Central Commission decided to bring parity for sharing the net savings as a result of SCED during the extended period with the benefit sharing mechanism (sharing of net gains) specified for Real Time Market (RTM) in respect of tied capacity of generators. The Commission directed that the net savings as a result of SCED after adjusting heat rate compensation for part load operation of the generators shall be shared in the following manner:

  As a first step, the share towards 'untied capacity' of merchant generators as well as generators with part capacity tied would be segregated from the net benefits, in the ratio of contribution of such generators to SCED, for every time block. The remaining benefits are then shared in the ratio of 50:50 between the generators (with tied capacity, participating in SCED) and the concerned beneficiaries/ Discoms, aggregated on a monthly basis as per Regional Energy Account (REA) and weekly SCED accounts in proportion to their final schedule from generator's share exceeds Rs. 0.07/ kWh the same is restricted to a ceiling of Rs. 0.07/ kWh and the gains over and above Rs. 0.07/ kWh would be shared among Discoms. The cap of Rs. 0.07/ kWh is, however, not be applicable in respect of 'untied capacity' of merchant generators as well as generators with part capacity tied, for its untied capacity.

  As per Annexure-3 of the draft procedure, the benefits shall be shared as follows -

  ".. 3. The benefits shall be shared in the ***ratio of 50:50 between the generators and the concerned beneficiaries****, aggregated on a monthly basis as per Regional Energy Account (REA)/ State Energy Account (SEA) and NLDC monthly SCED accounts.*

[3] https://posoco.in/wp-content/uploads/2021/04/POSOCO SCED_Expanded Pilot_Detailed Feedback Report Mar 2021.pdf

4. The total net SCED benefits corresponding to the Beneficiary shall be distributed in proportion to their final schedule from the SCED generator as per the Regional Energy Account (REA)/ State Energy Account (SEA).

5. In case of merchant generators, they shall be beneficiaries of their schedule generation as per REA/ SEA(other than SCED/SCUC) and this schedule energy shall be considered for deriving their share in other 50% saving marked for beneficiaries.

6. In case of part tied up generators, they shall be beneficiaries of their schedule generation under T-GNA and for rest capacity scheduled shall be shared with beneficiaries as per REA/ SEA for deriving their share in other 50% saving marked for beneficiaries.

… … … …

8. The benefits corresponding to the SCED generator out of the total Net SCED benefits shall be distributed in the ratio of their total schedule under SCED Up and SCED Down respectively. This shall be based on the block wise SCED Up and SCED Down energy aggregated on monthly basis. Benefits as computed above for the SCED generators would then be summed up for the month."

The ratio of sharing between SCED Up and SCED Down generators should be clarified and be retained as per the prevailing provisions. Also the absence of the cap in the benefits of the generator may lead to reduction in the overall gains of the beneficiaries and may lead to additional gains for the generators.

CERC (Staff Paper on Market Coupling), 2023

CERC notified "Staff Paper on Market Coupling" on 20th August, 2023. The key highlights of the draft are mentioned below:

- **Objective:** To evaluate the implications of the Market Coupling in Power Exchanges for Enhanced Price Discovery, Technological Innovation and Competition.
- Following are the key discussions and consideration:

  i. **Potential benefits in terms of price discovery:** In the overall transaction in power exchange, DAM and RTM accounts for more than 70% of total transactions. IEX dominates the collective transaction segment with almost 99% of share. Hence, it seems that the market coupling will not have any significant impact in terms price. discovery.

     Potential benefit of coupling in terms of uniform price discovery and best model should be discussed.

  ii. **Impact on technological innovation and competition:** The market coupling could potentially reduce the role of the exchange to mere traders whose role will be the collection of bids and financial settlement. There will be a centralized algorithm to accommodate the complex bid structures, which will result into no incentive for exchanges to innovate new products on their own. However, coupling could offer the gains in terms of increased liquidity, efficiency and competition as well as lower transaction fee.

  iii. **Entity for the role of the Market Coupling Operator (MCO):** There are two proposals regarding which entity will take the role of MCO.

     a. **Power exchanges as the MCO:**
        - Exchanges to perform the role of MCO on rotational basis.
        - Single algorithm to be used for price discovery.
        - Contractual agreement should be implemented between exchanges to avoid any kind of conflicts.
        - The market result obtained from the MCO can be validated by other exchanges in parallel.
        - Commission shall conduct periodic audits and analyses bid data as part of market monitoring and surveillance.

     b. **Third-Party MCO/ Super-Exchange:**
        - Third-party MCO will lead to less probability of conflict of interest.

- Grid-India broadly performs the MCO activities for the procurement of Tertiary Reserve Ancillary Services (TRAS) through the market.
- The entity will be regulated by the Commission.

iv. **Algorithm to be adopted for coupled market:** Huge investments have been done by the exchanges for the development of their algorithm for price discovery. Each algorithm is optimized to accept certain type of bids offered by a particular power exchange. Discussion on the following points should be done:

v. **Mechanism of balancing and settlement:** Main points to be discussed in the section are mentioned below:

a. Would MCO act as counterparty to the power exchange w.r.t settlement rights and obligations?

b. Would MCO charge transaction fee from the exchanges?

c. Structure of the grievance handling framework.

vi. **Change in settlement process:** Should traders submit their bids directly to the MCO to get away with the transaction fee of exchanges?

vii. **Selection of segments for the introduction of Market Coupling:** The important point of argument is the introduction of market coupling for the collective transaction segment to increase the competition, as it is the segment where the liquidity is concentrated in only one exchange.

EAL Opinion

- **Market Coupling - Need:** The Indian power market is characterised by geographical market coupling, similar to the one in the context of the European market. While coupling may theoretically bring economic benefits, it carries numerous challenges in its implementation. It is also important to understand the reasons for the inability of the smaller exchanges, one of which has been in the market for long, has not been able to make a mark in the key market segments. Apart from the bidding design (i.e. closed auction especially for the DAM and RTM market segments), perhaps certain business practices hasn't allowed others to gain market share in the key segments. Alternative effective steps may be identified to address specific challenges of the participating power exchanges.

- **Market Coupling - Distributional Impact:** While the objective of the proposal seems to be premised on the enhancing competition, it is also important to know if the dominant power exchange has misused its market power to influence its market share. If not, the distributional impact on a market player that hasn't misused its dominant position may seem an overstretch. Furthermore, in the short-run, there would be miniscule 'economic gain' as the volume in the other two power exchanges is very small. In the long-run, this would essentially become a tool for redistribution of market share. It would improve business prospects for the power exchanges, which face liquidity risk for some of the market instruments at the cost of the one that has built is clientele base perhaps through relatively more transparent business practices.

- **Derivative as a medium of Information Transmission among Power Exchanges:** The discussion paper aims to bring the idea of coupling of existing power exchanges across the country. One of the main reasons to implement the same could be to allow the transmission of information across the power exchanges. Currently the power exchanges operate in isolation such that the bid information of one exchange is not visible to other exchanges. One of the implications of the same is the diversion amongst the discovered clearing prices on the power exchanges. Derivatives market provides a platform for risk hedging. In the process, there is two way information transmission between the energy and the derivatives market. Another way of transmission of information between different exchanges can be through the derivatives market, wherein the underline of derivatives will be the MCP discovered under IEX since it is the largest and most liquid power exchange in the country right now. **Participants on the smaller exchanges can hedge against the diversion in those exchanges vis a vis the largest exchange, through derivatives (e.g. a futures contract) on the underlying DAM/ RTM price on the largest power exchange.**

- **Entry of Non-serious Players - Minimum Net-Worth Criteria for a Power Exchange:** The coupling of power exchanges will reduce its role from the discovery of MCP to a role of collecting and submitting the bids to the MCO. This will lead to the reduction in the capital expenditure requirement for an entity the play the role of exchange in the country, which can ultimately lead to an argument in favour of a reduction in the networth criteria of the power exchanges. This would open gates for more such bid collecting platforms seeking business license with a potential risk of enticing non-serious participants that may expose the market to a risk due to one of such platforms going out of business[4]. The reduction in the net-worth criteria for PXs can thus lead to the increase in inefficient services, frequent licensing and de-licensing of entities, etc.

- **Uniformity of Bid Design and Impact on Innovation:** Market coupling can only be implemented if all power exchanges have exactly same product with applicable bid types. It is important to highlight that power exchanges do differ in the context of bid types permitted across such platforms, even for the same product segment, for example, DAM/ RTM products differ across exchanges in terms of allowable bid types. Market coupling would thus impact product innovation, as coupling would enforce uniformity of product.

- **Dilemma of the Settlement Process between the Bidders and Power Exchanges:** Currently, the bids in the three power exchanges are cleared separately since all the power exchange operate independently in terms of bid clearing and calculation of MCP for the collective transaction segment. The process is illustrated via the figure below:

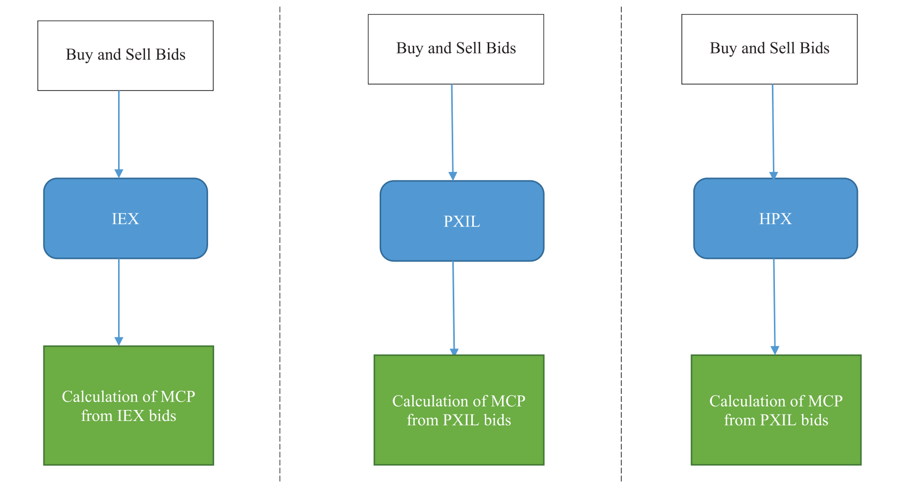


Figure 3: Current Mechanism of Price Discovery where all power exchanges are isolated

- After the clearing of volumes, the responsibility of settlement of transactions lies within the ambit of the respective exchange. Hence, each exchange acts independently while implementing the settlement process. Under the proposed mechanism, the buyer and the seller may have submitted bids on separate exchange platforms (Figure 3), thus leading to the issue of cross platform settlement process.

- **Choice of MCO and its Revenue Model:** Some of the key implementation issues would include selection of a New MCO or its implementation on a Rotational basis[5]. What would be the Revenue model for MCO? This may involve a regulated approach to determine charges to be levied by the MCO which would be then an integral part of the trading related charges.

- **Grievance Handling Framework for Disputes among Power Exchanges:** The proposed framework for market coupling requires a well-coordinated approach between the power exchanges. While the document discusses about the contractual agreement between the exchanges when the exchange itself operates as the MCO, a mechanism should also be put in place if a third party will play the role of the MCO.

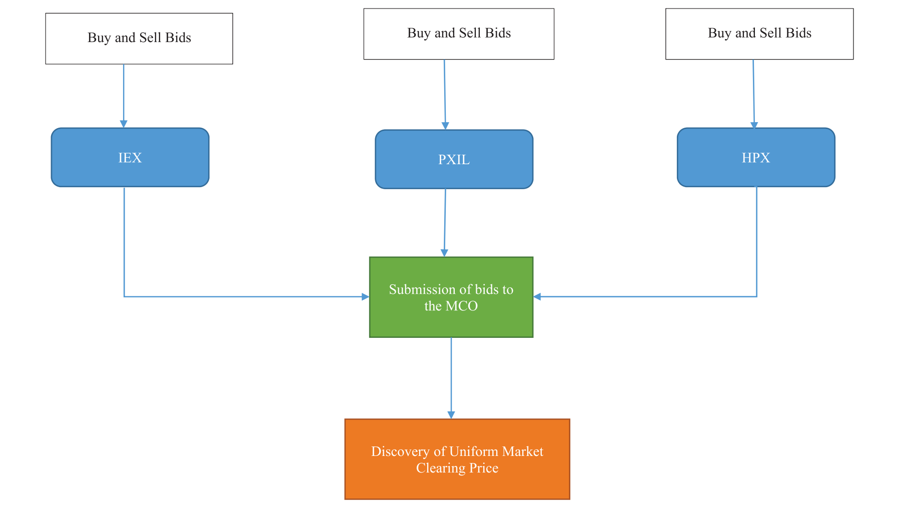


Figure 4: Proposed Mechanism of Price Discovery

- **Market Monitoring:** Effective role of competitive markets can

[4] Similar to the case of trading licensees, many of whom end up surrendering their licenses, sometimes causing disruption in the trading market.
[5] As in the case of geographical coupling of exchanges in the European context.

only be ensured with a robust market monitoring framework. The power market needs a well-designed market monitoring framework that should ensure a transparent, effective and timely implementation of market monitoring protocols. Public disclosure of the key indices of market monitoring, and transparent and timely reporting of the potential identified cases of market manipulation and investigation thereof would ensure greater trust of the market participants. In the context of market coupling such a framework should be able to ensure that market participants across platforms can be monitored through a unique ID.

Further References:

- **EAL comments on 'Grid India (Detailed Procedures for Security Constrained Unit Commitment (SCUC), Unit Shut Down (USD), and Security Constrained Economic Despatch (SCED) at Regional Level), 2023 [Draft]**.

  https://cer.iitk.ac.in/blog/new_blog/?id=MjMwMg==

- **EAL comments on MoP draft proposal on Day-Ahead operation of Security Constrained Economic Despatch, 2023.**

  https://cer.iitk.ac.in/blog/new_blog/?id=MjA5OA==

- **EAL comments on CERC (Staff Paper on Market Coupling), 2023**

  https://cer.iitk.ac.in/blog/new_blog/?id=MjMwMw==

- **EAL comments on Discussion Paper on Market Based Economic Despatch**

  https://cer.iitk.ac.in/blog/new_blog/?id=ODUx

EAL News

Stakeholder Consultation on "Market Derivatives for the Indian Power Sector"

EAL in association with CER & Shakti Foundation organised a closed door online stakeholder consultation on "Market Derivatives for the Indian Power Sector" on 29th September, 2023. The consultation aimed to identify the risks in the power market and their respective hedging mechanism from the perspective of various stakeholders. Power sector experts from Grid-India Ltd., CERC & SERCs, Renew Power, IEX & MCX participated and provided valuable insights. Additionally, the sector experts from DISCOMs, generation companies (conventional as well as renewables), trading licensees, captive generating plant and open access consumer actively participated in this event.

eMasters on "Power Sector Regulation, Economics and Management"

The classes for Cohort III of **eMasters Degree Program on "Power Sector Regulation, Economics and Management"** will commence in January, 2024. Application open for the admission to eMasters Degree program. Last date for registration is 31st October, 2023. It is a multidisciplinary online program, approved by Senate, IIT Kanpur. It focuses on developing insights into the development of electricity markets in India and discussing the challenges and way ahead. The program content explains the Regulatory process considering the applicable engineering, economics, legal and environmental viewpoints. Apart from faculty from relevant departments of IIT Kanpur, the sessions for the program would be contributed by leading national and international experts. The program is suited for officials/ employees of Regulatory Commissions, Government, Generation Companies (Thermal, Hydro and RE), Licensees (Transmission, Distribution and Trading), Equipment Manufacturers, Consultants, Academicians and other energy sector stakeholders including Green Hydrogen, Storage, EV, Coal, Oil & Gas etc. The Regulatory Capstone Projects will help the students to apply the concepts and devise solutions for real-life challenges. *https://emasters.iitk.ac.in/course/masters-in-power-sector.*

eMasters webpage

The industrial visit was organized for the participants of Cohort II of eMasters batch on 23rd and 24th June, 2023 at Grid India Ltd. - New Delhi, IEX - Noida, NPCL - Noida for enhancing the learning experience as part of the course.

We request your feedback for making EAL and this newsletter more relevant to the sector.
Log on to our portal or write to us at:

Contact Us (Publisher):
Energy Analytics Lab (EAL)
Department of Management Sciences
Indian Institute of Technology Kanpur
E-mail: eal@iitk.ac.in | *Follow us on :*
Phone: 0512-259 6448

eal.iitk.ac.in

Dr. Anoop Singh
Professor, Dept. of MS
Indian Institute of Technology Kanpur
Founder & Coordinator, CER and EAL
Website: www.iitk.ac.in/ime/anoops/

Other Initiatives

Centre for Energy Regulation

cer.iitk.ac.in