MINUTES OF THE 70th MEETING

OF THE

FORUM OF REGULATORS (FOR) HELD AT DIU

Venue	:	**Conference Hall, Azzaro Resorts, Diu**
Day / Date	:	**Friday, 31st January 2020**
List of Participants	:	**At Appendix -I (Enclosed)**

The meeting was chaired by Shri P.K.Pujari, Chairperson, Central Electricity Regulatory Commission (CERC) and Forum of Regulators (FOR).

In the Inaugural session, the Forum was joined by Dr. (Mrs.) Tapasya Raghav, Secretary (Power) for the Union Territories of Diu & Dadra and Nagar Haveli. She felicitated the Chairperson, CERC/FOR and other FOR members. In her welcome address, she thanked FOR for giving an opportunity to the administration of Diu to host the meeting. She stated that Diu has 6 MW peak demand from its HT and LT consumers. As per the objectives of the Union Government's Solar Mission, the Electricity Department of Diu has established 9 MW solar plant. She also stated that 115 government buildings have installed rooftop solar of 2.29 MW capacity and that the day-time peak load of power is entirely met from the solar power. All industrial consumers have been requested to install solar panels on rooftops and that the Diu administration has received 100% response to this initiative. She also apprised the Forum on the energy efficiency activities being taken up in Diu with the assistance of BEE (Bureau of Energy Efficiency).

Thereafter, Shri M K Goel, Chairperson, JERC (Goa & UTs) in his address welcomed the members of the Forum to the meeting in Diu. He informed the Forum that the per capita annual consumption of power in Diu was 8000 units which is almost 7 times the national average. The T&D losses in Diu is already around 6.1% as against the target of 6.7%. The Electricity department of Diu has achieved 100% metering for its 64,000 consumers and due to timely payment by the consumers, the Electricity department has sufficient revenue and does not depend on budgetary support from the Government. He once again thanked all members of the Forum for coming to Diu to attend the meeting.

In his address, Shri P.K.Pujari, Chairperson, CERC/FOR thanked the Secretary, Power of DNH and Diu for support for conducting the meeting of FOR. He apprised the Forum that a number of issues including references received from Ministry of Power and SERCs have been placed as agenda for discussion. There are also other items which require considerable deliberation before a consensus is reached. Chairperson, CERC/ FOR also informed that CERC is coming out with several new regulations which will have an impact on the future of the power sector. He placed on record his appreciation for the officials of JERC and the District administration for their assistance in holding this meeting and thanked Secretary (Power), DNH & Diu for sparing her time for this meeting.

After the inaugural session, Chairperson, CERC/FOR welcomed all the Members of the Forum to the Meeting. He also welcomed Chairperson, Meghalaya Electricity Regulatory Commission; Chairperson, Andhra Pradesh Electricity Regulatory Commission; and Chairperson, Telangana Electricity Regulatory Commission who were attending the FOR meeting for the first time. He also informed the Forum that Dr. M.K.Iyer, Member, CERC who has been a special invitee of FOR would be demitting office in the first week of February 2020. He placed on record the valuable contribution by Dr. Iyer to the FOR meetings.

Thereafter, the Forum took up the agenda items for consideration.

AGENDA ITEM NO. 1: CONFIRMATION OF THE MINUTES OF THE 69TH MEETING OF THE FORUM OF REGULATORS HELD ON 20TH SEPTEMBER, 2019 AT AMRITSAR, PUNJAB.

The Forum considered and endorsed the minutes of the 69th Meeting of FOR, held on 20th September, 2019 at Amritsar, Punjab.

AGENDA ITEM NO. 2:

a) ISSUE ON FLUE GAS DESULPHURIZATION (FGD) UNIT INSTALLATION - FINANCING

Chief (RA), CERC informed the Forum about a reference received from the Ministry of Power (MoP) on the issue of arranging funds for installation of emission control equipment for thermal power stations, raising working capital for such installations and granting of provisional tariff to generating station after installation of these equipment. The norms and benchmark capital cost issued by CEA **(Annexure I)** was discussed wherein the new regulations on emission, summary of new amendment and indicative cost of capex, opex etc. was detailed.

During discussions, it came to notice that some IPPs have filed petitions before the SERCs seeking approval of additional capital costs due to installation of FGD. However, some SERCs informed that they have received petitions from generators for installing FGD where the remaining useful life of the plant is only a few years and during that remaining period, it may not be possible to recover the cost of FGD installation through tariff. Some SERCs stated that a few of the plants in their State having a capacity less than 200 MW, were not covered by benchmark norms of CEA. They sought guidance from CERC in this regard. In response, Chairperson, CERC stated that in his view, the SERCs need to take a considered view on case to case basis. He informed that CERC had declared the MoEFCC notification on revised emission norms as a change in law event. He also informed that CERC had given in-principle approval of cost for installation of FGD in a few cases based on CEA norms and after those plants had approached the Commission for approval of costs arrived through a process of competitive bidding. He suggested that SERCs should take a holistic view considering the remaining useful life of the plant, efficiency of the plant, availability of power for the State from other sources, benchmark cost and norms issued by CEA etc. As regards, provisional tariff, he informed the Forum that CERC Regulations do not provide for any provisional tariff. Before grant of tariff, it was necessary for a generating station to first install FGD equipment and only thereafter the tariff should be granted after hearing the procurers. He informed that grant of provisional tariff is likely to violate provisions of the Electricity Act, 2003 and he referred to a few decisions of Hon'ble High Courts.

Chairperson, CERC/FOR added that CERC is also contemplating to amend the Tariff Regulations 2019-24 to provide for norms for installation of FGDs for complying with the environmental operating norms as Change in Law.

The Forum agreed that as the new environmental norms for installation of FGDs have been considered as change in law by CERC in various orders, these orders of CERC and such issues along with benchmark norms by CEA can serve as reference documents for SERCs to decide such matters on case to case basis.

b) REDUCTION IN COST OF POWER DUE TO PREPAYMENT IN ENTIRE VALUE CHAIN OF POWER SECTOR

Chief (RA), CERC apprised the Forum about a reference received from Ministry of Power wherein the SERCs were requested to take into account advance payment made by discoms/ procurers for reduction in tariff of generation/ transmission/ distribution. SERCs were also requested to develop an appropriate rebate mechanism for such discoms who opt for the advance payments as per Order of Ministry of Power. SERCs were also requested to provide a reduction in generation tariff for the competitively bid projects.

It was agreed that an action taken report may be submitted by SERCs to FOR Secretariat so that the same is forwarded to MoP.

AGENDA ITEM NO. 3:

REFERENCE FROM KARNATAKA ERC REGARDING REQUIREMENT OF AMENDMENT OF CLAUSE 6.4(i)(iii) OF THE TARIFF POLICY w.r.t. CAPPING RATE REALISED UNDER THE REC MECHANISM

Chairman, Karnataka ERC made a presentation **(Annexure II)** on the said subject. He drew attention of the Forum to the falling RE Tariff that had become competitive, if not lower, compared to that of thermal power tariff. He stated that considering the drop in RE tariff, there is a need to review the reference of APPC in the context of REC. He stated that KERC has already notified a cap on the APPC. He referred to a case wherein TNERC had fixed a cap of 75% of APPC in its Regulations which was challenged by Simran Wind Power Pvt. Ltd., before Hon'ble Madras High Court. The Hon'ble High Court upheld the Regulations of TNERC stating that TNERC has powers not only to determine the tariff but also to impose conditions. In view of this decision, KERC has also issued KERC (Procurement of Energy from Renewable Sources) (Seventh Amendment), Regulations, 2019 capping APPC in Karnataka also.

After discussion, the Forum agreed that the SERCs are free to take a view on APPC for REC projects in line with the decision of the Hon'ble Madras High Court. The Forum also requested CERC to arrange for a detailed presentation on the REC framework. To this, Chief (RA) informed the Forum that CERC is in the process of finalising the draft report on “Regulatory Impact assessment of RECs” and that a presentation on the same will be arranged in the next meeting of the FOR.

AGENDA ITEM NO.4: REFERENCE FROM ODISHA ERC

a. **Implementation of E Court webtool for all SERCs/ JERCs**

Chairman, OERC requested FOR Secretariat for an update on the implementation of the generic E-Court webtool as OERC is keen to implement the same considering its advantages. He also requested if FOR can meet the costs of this generic tool.

Dy Chief (RA), CERC apprised the Forum that the FOR Secretariat had sent a proposal in October 2018 to the Ministry of Power (MoP) seeking a one-time grant of Rs. 62 lakhs for implementing the E-Court webtool in 6 pilot States. MoP had raised a few queries in November 2019 seeking to know if the funds for the generic tool can be met from the Plan funds of FOR and whether FOR Secretariat was planning to go for competitive bidding for selecting the software developer. She stated that MoP was informed that the project would be taken up through NIC and that it needs to be funded through MoP since FOR does not have enough funds for the purpose. She stated that FOR Secretariat expects to receive a response from MoP soon.

In this regard, the Forum directed the FOR Secretariat to once again send a reminder to MoP seeking early release of funds. It was also decided that given the keenness of FOR members to implement E-Court webtool, the proposal of FOR funding the same in the event of no response from Ministry of Power may also be taken up in the next meeting.

b. **Higher Inter-State Point of Connection charges for Eastern States**

As a presentation on the same subject was already scheduled as agenda item No. 5, this issue was proposed to be taken up with the same.

AGENDA ITEM NO. 5 : DRAFT CERC (SHARING OF INTER-STATE TRANSMISSION CHARGES AND LOSSES) REGULATIONS, 2019

Chairperson, OERC observed that Point of Connection (POC) charges for certain States have increased substantially. He stated that the SERCs are interested to understand how the POC mechanism works. In response, Member CERC (Shri I.S.Jha) informed the Forum that in view of some difficulties in the existing system, it is being amended and stated that Joint Chief (Engg), CERC would make a presentation on the Draft CERC (Sharing of Inter-State Transmission charges and losses) Regulations, 2019. The presentation is at **Annexure III.**

Joint Chief (Engg), CERC, explained that the transmission charges as per the existing POC mechanism are sensitive to distance, directions and quantum of power flow as required under the Tariff Policy. A Task Force constituted by CERC that was headed by Shri A.S.Bakshi, Ex-Member, CERC has gone into recommending amendments required in the existing regulations and based on the recommendations of this Committee, the new draft Sharing regulations have been framed. The public hearing for the draft regulations has been concluded in January 2020.

She stated that monthly transmission charges to be collected from the users of ISTS through the POC mechanism amounts to Rs 3700 crores. Joint Chief (Engg), CERC further explained that once the projected peak generation and peak demand is obtained, load flow studies are run based on the actual load flow and then divided into 9 slabs for calculation of the monthly transmission charges.

Member, CERC (Shri I.S.Jha) added that POC is actually measuring utilisation of line at a particular time and that while it would seem distorted at a particular point of time, over the years, the same would average out. He added that it also depends on data and projections which keep changing.

Chairperson, KSERC raised a concern that while transmission lines had been planned based on request of a few States, the LTA charges have been subsequently loaded onto other States since the generators for whom those lines were being constructed, have relinquished LTA. Chairperson, OERC raised the issue of Odisha paying higher POC charges even though its maximum drawal is from its intra-State generators.

Chairperson, OERC informed the Forum that per unit transmission charges for users availing STU network is merely 25 paise per unit whereas the transmission charges are 70 paise per unit for using the CTU system. This huge difference between the STU and CTU charges leads to distortion in merit order. He informed that Punjab too has the same issue where transmission charges for using STU network is 21 paise per unit while that for CTU is Rs. 1 per unit. He suggested that the transmission charges could be a function of power consumption of a State. Chairperson, JSERC stated that the Forum could explore the concept of one country, one transmission charge.

In response, Joint Chief (Engg), CERC informed the Forum that as per CERC data, the average rate in India is 40 paise per unit. She informed that the CTU drawal cost by Chhattisgarh is 9 paise per unit; for Rajasthan, it is 35 paise per unit; and Odisha pays 66 paise per unit. Joint Chief (Engg), CERC further clarified that in case of Odisha, historically, Odisha has been scheduling maximum power from generating stations located within the State, but it has lesser LTA, due to which the transmission charges for drawal of power from ISTS are high. She also brought to the notice of the members of the Forum that the State Discoms during the public hearing of the proposed new sharing regulations had requested CERC to exclude the captive power plant in Odisha from the LTA charges and as these captive plants make purchases from outside, the LTA charges are high.

To these queries and statements, Chairperson, CERC/FOR and Member, CERC stated that at this stage when we have one grid, common market in the country as a whole, one cannot conceive of investment in transmission in isolation. He added that the sharing regulation is about apportioning the amount of Rs. 3700 crores amongst the users. In this process, some States would have to pay more while some others would pay less and as per the new methodology, a large part of such charges would depend on the load flow. He also requested the Forum members to go through CERC Order in Petition 92/MP/2015 where issues related to relinquishment and recovery of costs thereupon have been addressed.

Chairperson, KSERC enquired whether the CTU and central generating companies file their yearly true up petition for transmission charges as is being done by SERCs. In response, Secretary, CERC clarified that the CTU (PGCIL) submits true up petitions in respect of all its assets every 5 years. Chief (RA), CERC added that the same is based on the MYT (multi-year tariff) principles enunciated in the Tariff Policy which is to give certainty for 5 years and that if the exercise is done on a yearly basis, the spirit of MYT would be lost. He further informed that CERC follows the mechanism of sharing of gains in case of over-achievement and after assessment of efficiency at the end of the control period, the same is factored in the next set of regulations.

To conclude, Chairperson CERC/FOR stated that the concept of POC is complicated as it depends on load flow. He also referred to a report of the Ministry of Power on the same subject and stated that comments as highlighted by the FOR members have been raised by stakeholders before CERC and the Commission would give due regard to all such views before finalizing the revised regulations on sharing of transmission charges.

The Forum noted the same.

AGENDA ITEM NO. 6: UPDATE ON THE EXPERT GROUP REPORT ON THE RESERVES AND ANCILLARY SERVICES AT THE STATE LEVEL (SANTULAN) REPORT

Chief (RA), CERC drew attention of the Forum to the two specific interventions of CERC viz. regulations on Ancillary Services and Order on Security Constrained economic dispatch (SCED). He updated the Forum that POSOCO has at its discretion the unrequisitioned surplus (URS) of the central generating stations to meet the Ancillary Services requirement. A pilot on the SCED has been started since April 2019 and the same has led to cost savings to the tune of Rs. 3 crores per day as per initial estimates. In this situation, POSOCO is contemplating to scale up the pilot by involving more generating stations under SCED.

This gave an insight to the Standing Technical Committee constituted by FOR and a separate group was constituted to explore framework similar to SCED at the State level. The members of this group visited the States and also ran simulations on the software of POSOCO. The States of Gujarat and Madhya Pradesh showed significant savings in these simulations. The group opined that the SLDCs can be mandated to do similar exercise in their States and a co-optimisation exercise can be run closer to real time to use the URS to meet energy and balancing requirements. Hence, there is a need for basic regulatory framework on this scheme so as to roll out this scheme in the States. The recommendations of this group were endorsed by the Standing Technical Committee constituted by FOR. The

Report also includes Model regulation. Hence, Chief (RA), CERC submitted the report of the expert group for endorsement and adoption by the FOR.

After deliberation on the features of the report, the Forum appreciated the efforts of the group. Comments, if any, on the Report and Model Regulations **(Annexure IV)** may be sent by SERCs to FOR Secretariat within 60 days, post which suitable refinements as required may be made and uploaded on FOR website after seeking approval of Chairperson, CERC/FOR.

AGENDA ITEM NO. 7: REFERENCE FROM NATIONAL SMART GRID MISSION, MINISTRY OF POWER, GOVERNMENT OF INDIA ON PEAK LOAD MANAGEMENT AND SMART PREPAID METERING

Director, PMU-NSGM made a presentation **(Annexure V)** before the Forum on the initiatives which need support from SERCs so that there is a change in the way in which the load and future of power systems is managed. He gave a brief background on the National Smart Grid and stated that all the States are expected to have State level units to evolve their smart grids. He suggested that the Forum members may visit the smart grid knowledge centre in Delhi. He explained the need for smart grid for utilities and how it has contributed to system improvement, reliability improvement, enabling new products, enabling customer choice for power system, reducing operating and maintenance costs etc. He requested the Forum to nudge the utilities to institutionalize the pilots and that NSGM could provide solutions for such initiatives. He emphasized on the need for demand response program which is voluntary in nature and is incentive-based. Energy shift would be the primary target for which there would be a need for dynamic tariff design. Demand Response for peak load can be used to avoid setting up of additional infrastructure. Demand response for EV charging can be based on time slots. Hence, there is a need for creation of an ecosystem for demand response for quicker offtake and sustainability. He stated that way forward could be installation of AMIs and data analysis from such AMIs. It was further informed that NSGM has created a smart tool for utilities which is a tool for assessing smart grid readiness and self-assessment.

The Forum sought to understand more about the knowledge centre and what kind of support it could give to the SLDCs. Director, PMU-NSGM informed that the same was located in the PGCIL office at Gurgaon. The knowledge centre gives exposure on technology, communication, metering etc. The knowledge hub of

NSGM also provides regular training programs sponsored by the Smart Grid Mission and PGCIL. New technology and new solutions could also be tested there along with integration with distribution systems in addition to running simulations for procurement of RE and distributed resources. On a query from Chairperson, CSERC on smart billing, Director, NSGM responded that smart billing is a small component which contributes to a smart utility and not smart grid. He clarified that AMI does not prohibit paper bills and that it could give periodical inputs and requested the Forum to encourage the discoms to go in for smart grids.

The Forum appreciated the presentation.

AGENDA ITEM NO. 8:

a. **ELECTRICITY REGULATORY INFORMATION ACCESS AND ANALYTICS PLATFORM**

Chief (RA) updated the forum that under PSR program (partnership between Government of India and Government of UK), KPMG is the consulting agency to assist on several issues on power sector reforms. KPMG along with ABPS is assisting the FOR to develop an online platform where comparative statements on important data inputs for tariff and related inputs can be accessed. It was informed that the draft formats were devised and were approved earlier by the Forum. Subsequently, senior officers of SERCs were invited for a day long workshop where they went into the data formats and as per the feedback received, the data formats were redesigned. Now, the team of KPMG and ABPS have prepared a web tool and web page which gives an insight on comparative statements.

The representative from DFID thanked the Forum of Regulators and gave a brief of the tool. She stated that the objective of the tool is to promote exchange of information among policy makers, discoms and stakeholders. The tool provides information on a single platform on data parameters such as average cost of supply, average billed revenue, regulatory assets, RPO, consumer protection, open access etc.

Thereafter, the team of consultants from KPMG and ABPS made a joint presentation **(Annexure VI)** on the webtool. They explained key functionalities of the webtool with live demo. They also showed a sample case of national level dashboard w.r.t. sales, revenue, average cost of supply, power purchase cost, O&M

costs, State-wise data and other information which could be downloaded. The tool also showed the All India averages and State wise averages.

After viewing the various features of the webtool and discussions thereon, the Forum decided as under:

i. The webtool be launched, but to start with access be limited to CERC and SERCs for a period of one month. The consultant to share userid and passwords with CERC/ SERCs. FOR Secretariat to obtain a feedback after this trial and before the next FOR meeting.
ii. The portal be integrated with FOR website.
iii. SERCs will upload the data on to this portal after the support period under PSR expires. During the support period, consultant to update data from FY 20 and FY 21 tariff orders.
iv. The portal to also include data formats related to DVC (in the States of Jharkhand and West Bengal) and for submission of information to APTEL (duly modified as suggested by SERCs).
v. Documentation and coding of the platform to be shared with FOR Secretariat.
vi. Ownership and copyright to be retained by FOR Secretariat.
vii. KPMG/ ABPS under the PSR program to also undertake another study on "Analysis of electricity tariffs and impact of various factors (controllable and non-controllable) over the last 5 years which affects cost of supply i.e. raw material cost, taxes/ clean energy cess, excise duty, RPO, efficiency, etc". The study may be taken up in the next 6 months in 6 pilot States of Kerala, Odisha, Karnataka, Assam, Madhya Pradesh and Bihar after due consultation with the SERCs of the pilot States.

b. **APTEL DIRECTIONS DATED 23.09.2019 IN OP 1 OF 2011**

Chief (RA), CERC apprised the Forum that APTEL in matter of OP 1 of 2011 had sought various types of information and in order to comply with the same, FOR Secretariat had compiled the data on various tariff parameters as received from the SERCs and forwarded the same to APTEL.

However, considering that same data may be required to be submitted in future to APTEL, a format has been developed and the same can be used to submit information to APTEL. The Regulatory tool developed by KPMG will incorporate this data format so that periodic information can be received.

After discussion on the format, the Forum decided as under:

a. The format proposed by FOR Secretariat **(Annexure VII)** is approved in-principle. SERCs to give further comments, if any within 15 days, which will be incorporated by FOR Secretariat.
b. Data in this format will submitted to APTEL as per directions of APTEL.

AGENDA ITEM NO. 9: ECONOMICS AND REGULATORY FRAMEWORK OF ENERGY STORAGE – AN INSIGHT FOR INDIA BASED ON INTERNATIONAL EXPERIENCE – STUDY BY LBNL, USA AND CERC STAFF

Dr. Nikit Abhyankar, Scientist, LBNL and Chief (RA), CERC presented a regulatory framework for introduction of energy storage in India **(Annexure VIII).** They explained how the battery storage technology has changed over the last few years and that the battery prices have dropped by 80-90% between 2010 and 2020. They informed the Forum that in the US, solar and 3-4 battery storage PPAs have been signed at an unsubsidized price of 4-5 cents/kWh (Rs. 3-4/kWh) for delivery in 2021-2022. They also presented their recent work on assessing the grid-scale battery storage costs in India. LBNL estimates that in India, by 2022, solar along with 3-4 hour storage should be available at a levelized cost of Rs. 4/kWh. By 2030, this cost is likely to drop to Rs. 3/kWh. These costs raise a serious issue about the cost-effectiveness of new investments in thermal power.

They also presented a preliminary analysis assessing the dispatch of thermal power plants by 2030 if 450 GW of RE is installed - about 150 GW of thermal capacity will likely be dispatched as deep base load with an annual PLF of ~80%. About 50-60 GW will be dispatched at an annual PLF of 30-40%, raising their average cost of generation to over Rs. 5-6/kWh. About 50-60 GW thermal capacity will be dispatched at 10-15% annual PLF, raising their average cost of generation to over Rs. 10/kWh, which may lead to potential stranding. About 140-150 GWh of battery storage, along with agricultural load shifting to solar hours, can help avoid such potentially inefficient thermal investments. They also showed a case study for Karnataka, where significant agricultural load has already been shifted to solar hours. Their study finds that ~12 GWh of diurnal energy storage (batteries or pumped hydro), nearly 7 GW of potentially stressed new thermal investment could be avoided in Karnataka alone by 2030. Finally, they discussed the key regulatory framework around battery storage in the US and key takeaways for India.

It was suggested that the SERCs could conduct more nuanced planning exercises using resource adequacy analysis that assesses hourly system requirements and supply through the year. SERCS can also consider allowing storage to participate in the energy market both as a generator and a load, technology neutral storage deployment mandate, rewarding fast-response ancillary services etc.

Dr. Nikit informed that LBNL is currently collaborating with CERC under the US-India Flexible Resources Initiative project that would assess the overall system flexibility requirement in India up to 2030 and provide regulatory recommendations for enabling the system flexibility. They would also work with key States on that issue.

After deliberations, the Forum decided as under:

i. Resource Adequacy requirement as to how to meet load and at what cost needs to be studied. Guiding principles be developed in this context in the next 3-4 months and LBNL to develop a tool for this over the next 4 to 5 months.
ii. SERCs may support the Flexibilisation Resources initiative by the US Department of State and LBNL.
iii. It was decided to create a working group of interested/ key States for conducting the detailed resource adequacy studies in the wake of RE expansion, assess the impact on thermal assets, and create a regulatory framework around energy storage.

On conclusion of the meeting, Dr M.K.Iyer, Member, CERC informed the Forum that he was demitting office in February 2020. He recalled his 5-year long association with the Forum and stated that he was grateful to the Forum for sharing their vast knowledge.

Shri Sanoj Kumar Jha, Secretary, CERC/ FOR thanked the Chairperson, Members, Secretary and staff of the Joint Electricity Regulatory Commission (Goa & UTs) for their painstaking efforts and excellent logistics support to host the 70th Meeting of FOR at Diu. He also thanked all the dignitaries present in the meeting. He thanked the staff of FOR Secretariat for their arduous efforts in organizing the meeting.

The Chairperson, CERC/ FOR conveyed to the Members of Forum that the next FOR Meeting will be held in New Delhi in April 2020.

/ APPENDIX – I /

LIST OF PARTICIPANTS OF THE 70TH MEETING

OF

FORUM OF REGULATORS (FOR)

HELD ON 31st JANUARY 2020 AT DIU.

S. No.	NAME	ERC
01.	Shri P.K. Pujari Chairperson	CERC/FOR – in Chair.
02.	Justice (Shri) C.V. Nagarjuna Reddy Chairperson	APERC
03.	Shri Subhash Chandra Das Chairperson	AERC
04.	Shri S.K. Negi Chairperson	BERC
05.	Shri D.S. Misra Chairperson	CSERC
06.	Shri Depinder Singh Dhesi Chairperson	HERC
07.	Shri S.K.B.S. Negi Chairperson	HPERC
08.	Dr. Arbind Prasad Chairperson	JSERC
09.	Shri M.K. Goel Chairperson	JERC (State of Goa & UTs)
10.	Shri Shambhu Dayal Meena Chairperson	KERC
11.	Shri Preman Dinaraj Chairperson	KSERC
12.	Shri P. W. Ingty Chairperson	MSERC
13.	Shri U.N. Behera Chairperson	OERC
14.	Shri T. Sriranga Rao Chairperson	TSERC
15.	Shri D. Radhakrishna Chairperson	TERC
16.	Dr. Akhilesh Kumar Ambasht Member	DERC
17.	Shri P.J. Thakkar Member	GERC

18.	Shri Mukul Dhariwal Member	MPERC
19.	Shri Mukesh Khullar Member	MERC
20.	Shri Santokh Singh Sarna Member	PSERC
21.	Shri Kaushal Kishore Sharma Member	UPERC
22.	Shri M.K. Jain Member	UERC
23.	Shri Sanoj Kumar Jha Secretary	CERC
24.	Dr. Sushanta K. Chatterjee Chief (RA)	CERC
25.	Ms. Rashmi S. Nair Dy. Chief (RA)	CERC

SPECIAL INVITEES

26.	Dr. M.K. Iyer Member	CERC
27.	Shri Indu Shekhar Jha Member	CERC
28.	Ms. Shilpa Agarwal Joint Chief (Engg.)	CERC
29.	Dr. Nikit Abhyankar Scientist- Head	International Energy Analysis Department's research on power sector. LBNL, U.S.A.
30.	Shri Arun Kumar Mishra Director	NSGM
31.	Shri Atul Bali Sr. General Manager	NSGM
32.	Shri Suresh Gehani Director	ABPS Infrastructure Advisory Services Ltd
33.	Shri Ramit Malhotra Manager	KPMG India
34.	Ms. Sangeeta Mehta Senior Deputy Programme Manager	DFID, Government of UK
35.	Ms. Debaleena Saha Programme Officer	DFID, Government of UK

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Annexure-I

सत्यमेव जयते	**NORMS FOR INSTALLATION OF FGD** **for** **NEW ENVIRONMENTAL REGULATIONS - 7th December-2015** **(FROM 21st Februry, 2019 ONWARDS)**	केविप्रा cea

BRIEF REVIEW OF THE NEW MOEF&CC ENVIRONMENTAL RULE

The notification from MoEF&CC dated 7th December-2015 amends existing norms related to emission of SPM and introduces new norms for emission of SO_2, NO_x and Mercury from Thermal Power Plants (TPPs). It also specifies modified limits for specific water consumption by TPPs and insists [illegible]

सत्यमेव जयते	NORMS FOR INSTALLATION OF FGD for NEW ENVIRONMENTAL REGULATIONS - 7th December-2015 (FROM 21st Februry, 2019 ONWARDS)	

3	New plants to be installed after 1st January 2017 shall have to meet specific water consumption up to maximum of 2.5 m^3/MWh and achieve zero waste water discharged.

Further, to the above MOEF & CC notification, MOEF &CC has subsequently issued an amendment dated 28th June 2018 for

TECHNOLOGY SELECTION

The So_2 reduction technology shall be done considering following factors:

1: Sulphur Content in Coal.

2: So_2 removal Efficiency requirement of particular plant.

3: Availability of Reagent (if Any).

4: Disposal and handling of By-product.

5: Locational/Geographical factors of the plant.

6: Plant life.

7: Space requirement for FGD facility.

COST

CAPEX:

The cost estimation given below is only indicative in nature and discovered through open competitive bidding for the projects already awarded:

CAPACITY GROUP (MW)	LAKH PER MW #
210	45
250	
300	43.5
500	40.5
525	
600	37
660	
800	30
830	

The above CAPEX is "**Base Cost**" only, this base cost is with new chimney and without GGH and does not include Taxes-Duties and Opportunity Cost for interconnection.

The above Base cost may further vary as per the following conditions:

1. The increase in no. of units will reduce the CAPEX because of common facilities.
2. Range of SO_2 removal.
3. Chimney Layout such as using existing chimney as wet stack, new wet stack with single or multi flue cans, Chimney above absorber, provision of temporary chimney for making existing chimney operational and chimney material.
4. Choice of Corrosion protection lining in chimney, absorber and other sections of FGD.

Note: The cost may further come down in future due to increased number of vendors/suppliers as the market matures.

OPEX:

Operating Cost (OPEX) of FGD will be dependent on Reagent cost (if any), cost of Additional water consumption, O&M Manpower cost, APC of FGD, By-product handling and revenue earned through disposal of by-product (if any) etc.

AUXILIARY POWER CONSUMPTION:

Auxiliary Power Consumptions (APC) is estimated to be maximum 1% for FGD operations. In case GGH (Gas to Gas Heater) is used maximum 0.3% additional APC may be required.

OPPORTUNITY COST:

Since interconnection of chimney with absorber may result in loss of generation, hence Power plants are advised to minimize this interconnection time by taking suitable measure so that the "Opportunity cost" associated with plant shutdown may have least impact on Tariff.

Annexure-II

Capping of Average Pooled Power Purchase Cost (APPC) under REC Mechanism

Presentation by Chairman,
Karnataka Electricity Regulatory Commission

Meeting of Forum of Regulators

31.01.2020

Provisions under EA, 2003 & Tariff Policy,2016

-

- **Provisions under Section 86(1) (e) of EA,2003 :**

  "promote cogeneration and generation of electricity from renewable sources ----;"

- **The Tariff Policy,2016 issued under Section-3 of the EA,2003 envisages the following objectives:**

  Promote generation of electricity from Renewable sources;

Clause 6.4(1)(iii) of Tariff Policy

- **Clause 6.4 of Tariff Policy deals with RE sources and Clause 6.4(1)(iii) specifies as under:**

"6.4(1) (iii) It is desirable that purchase of energy from renewable sources of energy takes place more or less in the same proportion in different States. To achieve this objective in the current scenario of large availability of such resources only in certain parts of the country, **an appropriate mechanism such as Renewable Energy Certificate (REC) would need to be promoted. Through such a mechanism, the renewable energy based generation companies can sell the electricity to local distribution licensee at the rates for conventional power and can recover the balance cost by selling certificates to other distribution companies and obligated entities** enabling the latter to meet their renewable power purchase obligations. The REC mechanism should also have a solar specific REC."

REC Mechanism

Under REC mechanism electricity component can be sold at APPC determined by SERC and the green component can be sold as REC by the RE generators in the market.

APPC is the average cost of power purchase excluding RE sources.

The Commission is determining the APPC every year.

Need for capping APPC under REC Mechanism

- Earlier RE tariff was higher than conventional power plant tariff. Hence, to encourage RE , the mechanism of REC introduced.

- In recent years, RE tariff has reduced and is below the tariff of conventional plants. Hence, under REC mechanism RE generators now would earn considerable profits considering the APPC and REC rate.

- HENCE CAPPING OF APPC REQUIRED.

Floor Price and Forbearance Price as per CERC Order Dated 30.03.2017

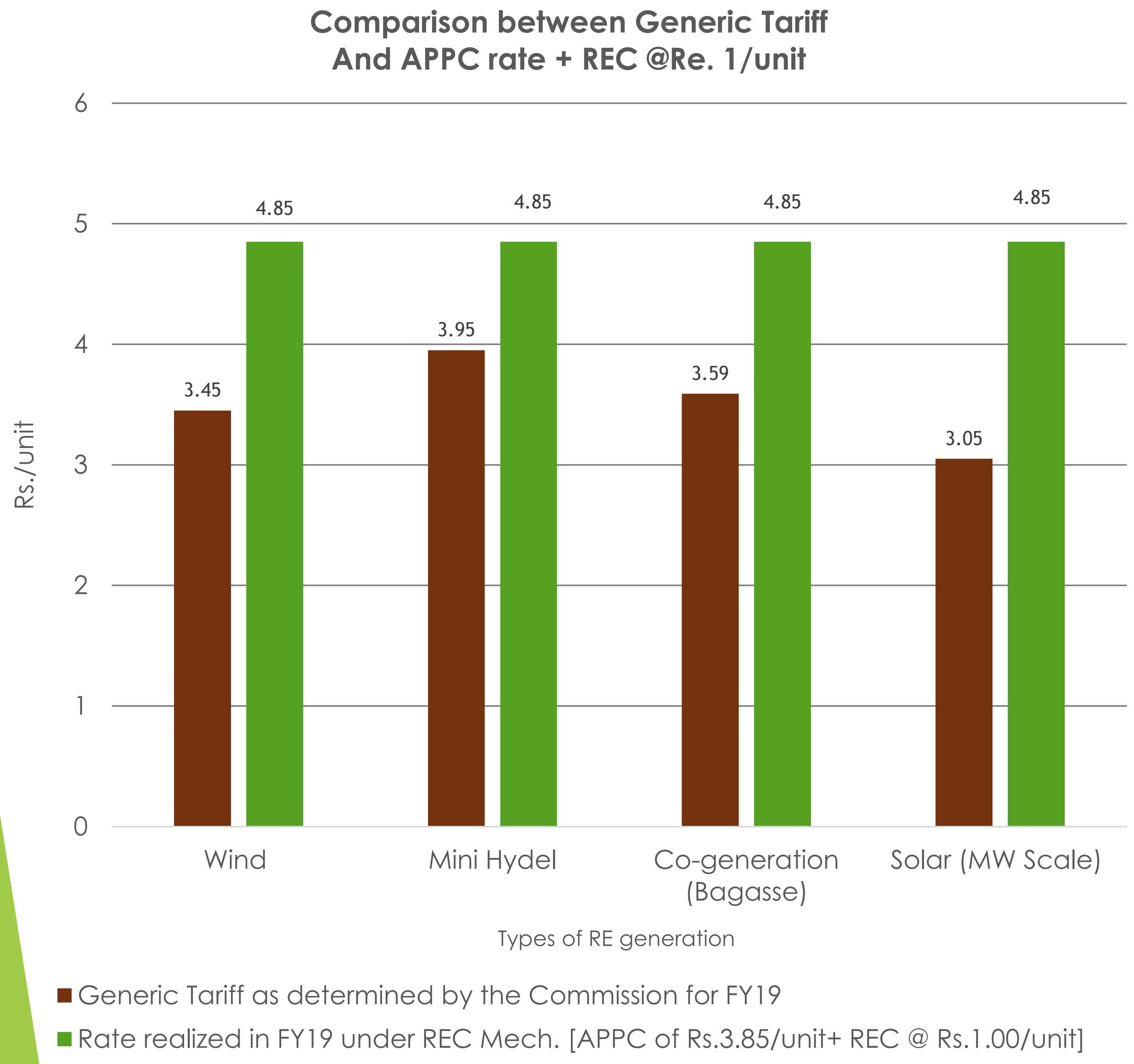
(Rs/ MWh)

Types of RECs	Floor Price	Forbearance Price
Non Solar REC	1,000	3,000
Solar REC	1,000	2,400

Impact of current APPC & REC rate in comparison to Generic Tariff

RE Source	Generic Tariff as determined by the Commission for FY19 (Rs. / Unit) (1)	Rate realized in FY19 under REC Mech. (Rs. / Unit) [APPC of Rs.3.85/unit+ REC @ Re.1.00/unit*] (2)	Difference (Rs. /unit) (3)
			(3)=(2) – (1)
Wind	3.45 (Ceiling price for Bidding)	4.85	1.40
Mini Hydel	3.95	4.85	0.90
Co-generation (Bagasse)	3.59	4.85	1.26
Solar (MW Scale)	3.05	4.85	1.80

Note: *As per CERC Order dated 30TH March, 2017, the Floor price is Rs. 1000 per MWh, which works out to Re. 1.00/unit



RE Source	Generic Tariff as determined by the Commission for FY19 (Rs. / Unit) (1)	Rate realized in FY19 under REC Mech. (Rs. / Unit) [APPC of Rs.3.85/unit + REC @ Re.1.00/unit] (2)	Difference (Rs. /unit) (3)
			(3) =(2) – (1)
Wind	3.45 (Ceiling price for Bidding)	4.85	1.40
Mini Hydel	3.95	4.85	0.90
Co-generation (Bagasse)	3.59	4.85	1.26
Solar (MW Scale)	3.05	4.85	1.80

Rate realized under REC mechanism considering APPC and weighted average of monthly price of RECs at IEX and PXIL

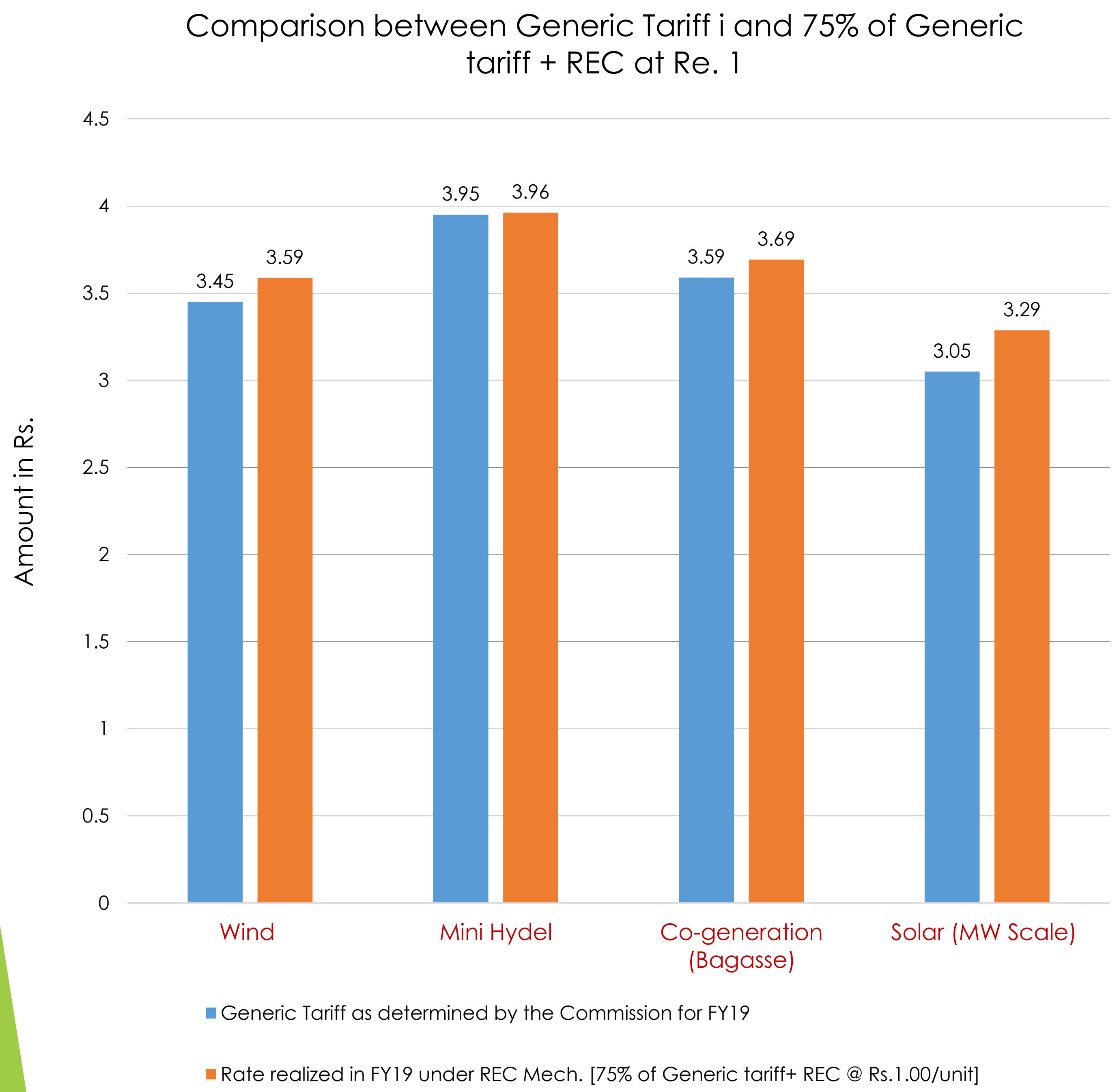
RE Source	Generic Tariff as determined by the Commission for FY19 (Rs. / Unit) (1)	*Rate realized in FY19 under REC Mech. (Rs. / Unit) [APPC of Rs.3.85/unit+ REC at Weighted average price at IEX] (2)	Difference (Rs. /unit) (3)	*Rate realised in FY19 under REC mechanism (Rs./unit) [APPC of Rs. 3.85/unit + REC at Weighted average price at PXIL] (4)	Difference (Rs./Unit) (5)
			(3) =(2) – (1)		(5)=(4)-(1)
Wind	3.45 (Ceiling price for Bidding)	3.85+1.31=5.16	1.71	3.85+1.27=5.12	1.67
Mini Hydel	3.95	5.16	1.21	5.12	1.17
Co-generation (Bagasse)	3.59	5.16	1.57	5.12	1.53
Solar (MW Scale)	3.05	3.85+1.11=4.96	1.91	3.85+1.07=4.92	1.87

*The rate realized under REC mechanism in Karnataka considering APPC of Rs. 3.85/unit and weighted average price of RECs at IEX and PXIL of Rs. 1.31/unit and 1.27/unit for non-solar RECs and Rs. 1.11/unit and Rs. 1.07/unit for solar RECs respectively for FY19.

Rate realized under REC mechanism considering APPC and REC at Maximum price at IEX and PXIL

RE Source	Generic Tariff as determined by the Commission for FY19 (Rs. / Unit) (1)	*Rate realized in FY19 under REC Mech. (Rs. / Unit) [APPC of Rs.3.85/unit+ REC at Maximum price at IEX] (2)	Difference (Rs. /unit) (3)	*Rate realised in FY19 under REC mechanism (Rs./unit) [APPC of Rs. 3.85/unit + REC at Maximum price at PXIL] (4)	Difference (Rs./Unit) (5)
			(3) =(2) – (1)		**(5)=(4)-(1)**
Wind	3.45 (Ceiling price for Bidding)	3.85+**1.50**=5.35	1.90	3.85+**1.56**=5.41	1.96
Mini Hydel	3.95	5.35	1.40	5.41	1.46
Co-generation (Bagasse)	3.59	5.35	1.76	5.41	1.82
Solar (MW Scale)	3.05	3.85+**2.00**=5.85	2.80	3.85+**1.91**=5.76	2.71

***The rate realized under REC mechanism in Karnataka considering APPC of Rs. 3.85/unit and maximum price of RECs for FY19 discovered at IEX and PXIL of Rs. 1.50/unit and 1.56/unit for non-solar RECs and Rs. 2.00/unit and Rs. 1.91/unit for solar RECs respectively.**



RE Source	Generic Tariff as determined by the Commission for FY19 (1)	Rate realized considering 75% of Generic tariff+ REC @ Re.1.00/unit (2)	Difference (3) (3)=(2)-(1)
Wind	3.45	3.59	0.14
Mini Hydel	3.95	3.96	0.01
Co-generation (Bagasse)	3.59	3.69	0.10
Solar (MW Scale)	3.05	3.29	0.24

Legal Aspect for Capping of APPC

- TNERC had fixed a Cap of 75% of APPC in its Regulations, which was challenged by Simran wind Power Pvt. Ltd., before Hon'ble Madras High Court

- Hon'ble High Court after examining the matter has upheld the Regulations of TNERC stating that TNERC has powers not only to determine the tariff but also to impose conditions.

- In view of the above decision , KERC has also issued KERC(Procurement of Energy from Renewable Sources)(Seventh Amendment), Regulations,2019 capping APPC.

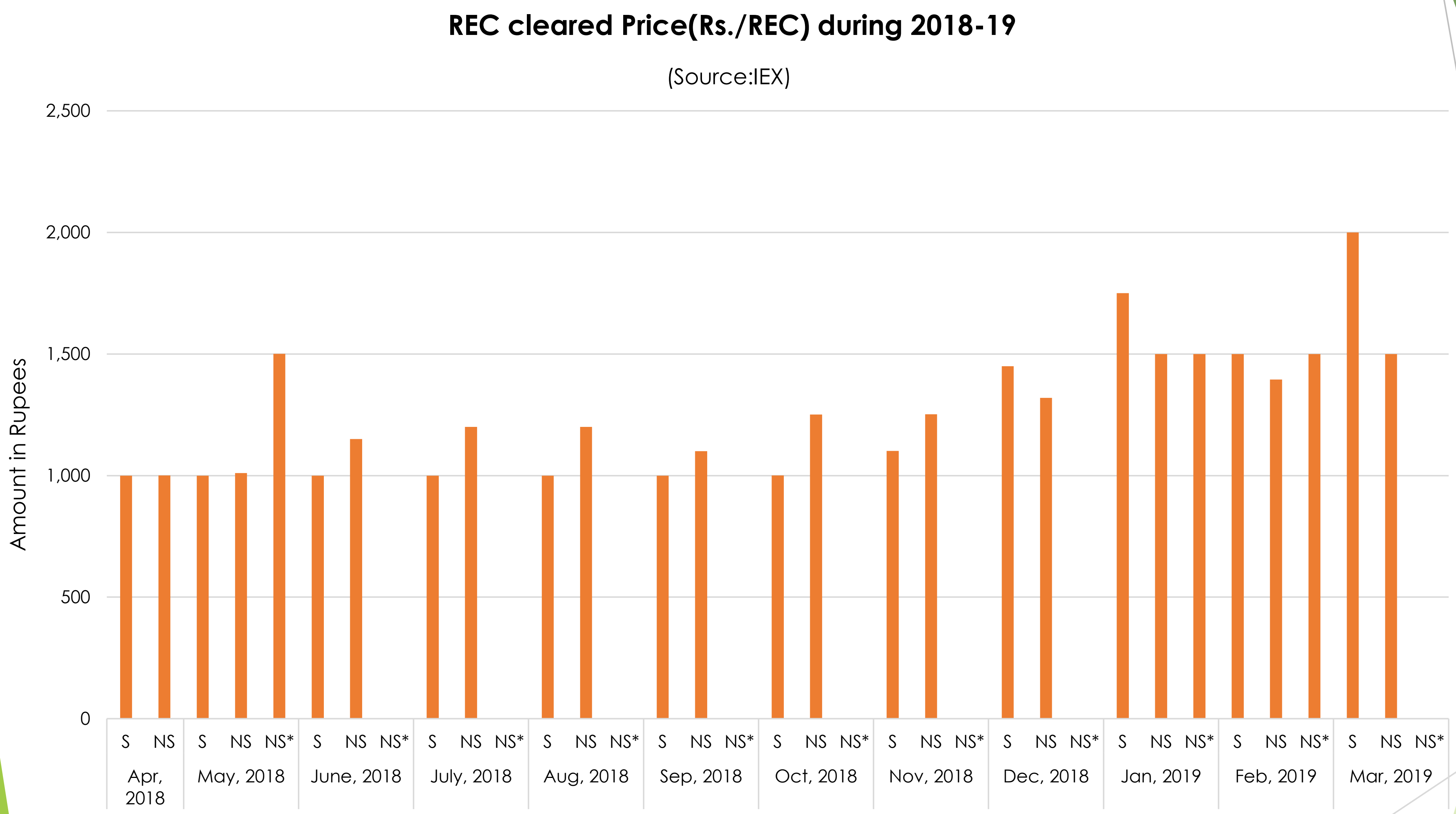
Proposal for Recommendation to MoP of the Amendment to Clause 6.4(1)(iii) of Tariff Policy for consideration of FoR

"6.4 (1)(iii) It is desirable that purchase of energy from renewable sources of energy takes place more or less in the same proportion in different States. To achieve this objective in the current scenario of large availability of such resources only in certain parts of the country, an appropriate mechanism such as Renewable Energy Certificate (REC) would need to be promoted. Through such a mechanism, the renewable energy based generation companies can sell the electricity to local distribution licensee at the rates of conventional power **or ----%* of the Generic Tariff determined by the respective SERCs, whichever is lower** and can recover the balance cost by selling certificates to other distribution companies and obligated entities enabling the latter to meet their renewable power purchase obligations. The REC mechanism should also have a solar specific REC."

[*Note: The Ministry may specify a suitable %]

Thank You

Open for Discussion



S= Solar, NS=Non-Solar;
*NS RECs issued prior to 2017

Note:1 REC=1 MWh @ Rs. 1000 per REC;
Therefore, for 1kWh REC price would be Re. 1.00

REC traded in IEX during FY19

Month	Type	Buy Bids (REC) (Nos.)	Sell Bids (REC) (Nos.)	Cleared Volume (REC) (Nos.)	Cleared Price (Rs/REC)
Apr, 2018	S	644,151	2,705,722	644,151	1,000
	NS	417,686	188,672	136,979	1,001
May, 2018	S	393,822	2,772,666	393,822	1,000
	NS	478,940	375,218	323,634	1,010
June, 2018	S	288,070	2,540,984	288,070	1,000
	NS	856,844	295,070	221,674	1,150
July, 2018	S	808,324	2,258,417	808,324	1,000
	NS	655,553	264,901	191,988	1,200
Aug, 2018	S	216,223	1,458,702	216,223	1,000
	NS	668,060	428,575	291,588	1,200
Sep, 2018	S	2,156,459	1,461,202	1,359,045	1,000
	NS	501,255	486,175	244,401	1,100
Oct, 2018	S	576,535	335,003	130,279	1,001
	NS	724,461	434,675	295,010	1,251
Nov, 2018	S	852,693	229,140	32,556	1,101
	NS	675,109	546,155	355,657	1,252
Dec, 2018	S	865,574	254,012	88,272	1,450
	NS	1,091,466	366,092	295,601	1,320
Jan, 2019	S	589,311	241,580	97,277	1,750
	NS	765,770	453,371	393,316	1,500
Feb, 2019	S	567,273	688,507	383,708	1,500
	NS	928,439	1,446,856	654,592	1,395
Mar, 2019	S	686,784	305,049	217,231	2,000
	NS	1,039,447	757,242	716,929	1,500

Decision of Hon'ble Madras High Court on the APPC Cap imposed by TNERC

WP.Nos.22097 and 32756 of 2013

Appellant: Simran Wind Power P. Ltd.

Respondent: TNERC

- **Issues (A):** Whether, the TNERC is within its powers to determine the APPPC under the REC Scheme contrary to the CERC Regulations, 2010?

Decision of the Hon'ble High Court: "14 f. Section 79 speaks about the functions of the central commission as a tariff determining authority relating to inter-state transactions and as an advisory body. It enables the central commission to regulate the tariff for sale or purchase of electricity between the states and also to regulate the tariff in case of sale by generating companies to more than one state. However, the power under this section is subjected to the regulations of the central commission framed under section 178. In case, the power is delegated to the state commissions either by operation of section 61, 62 or by virtue of delegation by the central commission by express or implied implications to the state commissions to determine the tariff and fix the procurement price applicable in case of sale by generating companies, the fixation by the state commission shall prevail."

"14 h. Section 178 deals with the powers of central commission to make regulations and section 181 deals with the powers of state commissions to make regulations under the act to implement the provisions of the Act. Sections 178 and 181 enable the central and state commissions to frame the regulations in consonance with the national plan and policy. A vigilant reading would spell out that the provisions are independent with similar power vested on both the authorities. The commissions are vested with the powers to pen down the terms and conditions, methods and procedures to be followed while fixing the tariff. Therefore, it is clear that the state commission is empowered to impose restrictions as well while fixing the tariff or procurement price in consumer interest."

Decision of Hon'ble Madras High Court on the APPC Cap imposed by TNERC

"14 i. Regulation 2(k) of the CERC Terms and Conditions for recognition and issuance of renewable energy certificate for renewable energy Generation, Regulations, 2010 defines preferential tariff to be the tariff fixed by the appropriate commission. The said definition has been deleted along with the modification of the definition of APPPC in 2013.The regulations without any shadow of doubt at various places expressly confirm the power of the state commission to fix the tariff. The definition of APPPC clearly spells out that the cost is to be determined at the average purchase cost of the distribution licencee which is actually fixed by the state commissions exercising its powers under sections 61, 62, 86 and 181.

22. ------*Here, from the explanation to the amendment, it is evident that the cap has been fixed to eschew the APPPC from exceeding the preferential tariff. The same has further been clarified in the counter. The said amendment has been brought into force, to safeguard the consumers interest as envisaged under **section 61** (d) of the Act and also at the same time, to balance the procurement cost of purchase price of electricity component. Therefore, this court is of the view that the amendment is neither vague nor arbitrary and therefore there is no violation of Articles 14 and 19 of the constitution.------"*

Decision of Madras High Court on the APPC Cap imposed by TNERC .....contd.

- **Issue (B):** Whether the TNERC by exercising its powers under the statute override the contract, entered into by the TANGEDCO with the petitioners in pursuance of its earlier directions?

Decision of the Hon'ble High Court:

- "26. The ratio laid down by the apex court is squarely applicable to the present facts of the case. What that flows from the ratio is that the powers of the CERC under section 79 are administrative and the powers under section 178 are legislative. Also, by exercising the legislative powers, the contractual terms can be overridden. The powers of the state commission under section 181 is pari-materia to that of the central commission under section 178. All that is required is that the regulation must be in conformity with the objects of the act and exercised in furtherance of the provisions of the act. Further, the judgement also clearly spells that the role of the regulatory commission is twin folds, namely, (1) decision making and (2) specifying terms and conditions for determination of tariff. Therefore, the TNERC would have the power not only to determine the tariff but also to impose conditions."

APTEL Order dated 31st May, 2019 in APPEAL NO. 232 OF 2017

- **Appellant:** Techno Electric & Engineering Company Ltd.
- **Respondent:** TANGEDCO and TNERC
- **Issues:**
  - The decision of TNERC that the APPC rate have been breached in the year 2013-14, by taking into account the preferential Tariff for a Wind Generator prevailing prior to 2006 which was Rs.2.75, and comparing it with the APPC rate of Rs.3.11 for 2013-14 was challenged.
  - In the above context Hon'ble APTEL took up the following issue for decision making:

"Whether in the facts and circumstances of the case and directions passed by Hon'ble Madras High Court in its Judgment dated 15.07.2016, the Impugned Order passed by the State Commission is sustainable in the eyes of law"

APTEL Order dated 31st May, 2019 in APPEAL NO. 232 OF 2017

…..contd.

- **Decision:**

"**12.1** The notification dated 19.06.2013 which amended the definition of the APPC shall not be given effect to in as much as till date, the APPC of a year has not exceeded the preferential tariff payable to wind generators for that corresponding year.

12.2 Being dynamic in nature (which may go up or down), the APPC rate shall be compared by the State Commission on year to year basis and the proposed cap of 75% under the amendment shall be implemented for a particular year in which APPC rate crosses over the rate of preferential tariff for that corresponding year.

12.3 The State Commission is directed to issue necessary instructions to Respondent No. 1 to make payment to the Appellant at the full APPC rate without applying any cap, for the relevant period, together with normal interest thereon at the rate provided for in the EPA from the date such capped tariff was effected by Respondent Discom until date of payment to the Appellant.

KERC (Procurement of Energy from Renewable Sources) (Seventh Amendment) Regulations, 2019

- Notified on 6th December, 2019.
- Sub-Clause(c) under Clause 7 of the existing Regulation shall be modified as under:

"(c) A generating company opting for REC scheme shall sell the electricity generated by it to ESCOMs of the State at the pooled cost of power purchase of the State for the relevant year, as notified by the Commission from time to time or at 75% of the generic tariff as determined by the Commission for the respective RE source for that relevant year, whichever is lower."

Annexure-III

Draft Sharing of Inter-State Transmission Charges and Losses) Regulations, 2019

Background

- Existing Sharing Regulations- notified on 15.6.2010, effective from 1.7.2011, 6 amendments till date.
- Review of framework-Taskforce under Member CERC, Sh A.S. Bakshi- Report dated March 2019.
- Proposed Draft Regulations- Committee under Member CERC, Sh.I.S. Jha
- Draft Regulations – 31.10.2019, comments till 31.12.2019, Public Hearing on 29.1.2020

Existing Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010

PoC for AC system

Hybrid of Average participation and Marginal Participation

- Projected maximum generation/demand for ensuing quarter
- Charges are put in 9 slabs

HVDC

shared by region for which it was created

- Biswanath Chariali –Agra- Shared by All India
- Mundra Mohindergarh- 1495 MW- by Adani Mundra and 1005 by all India

Reliability charge

10% of Yearly transmission charge

- Shared by all India DICs in ratio of LTA+MTOA

Issues raised by Stakeholders

- True up of projected data
- Marginally Utilised Lines
- Sharing of HVDC systems – POSOCO/CTU
- Sharing of Transformers- CEA
- Impact due to waiver of RE charges
  - Planning issues due to waiver
- Transparency
- Participation of discoms in planning

Monthly Transmission Charges

National Component (NC)

- National Component-HVDC (NC-HVDC)
- National Component-Renewable Energy (NC-RE)

Regional Component (RC)

- HVDC (RC-HVDC)
- STATCOM,SVC, Bus Reactors

Transformers Component (TC)

AC System Component (ACC)

- Usage Based Component (AC-UBC)
- Balance Component (AC-BC)

National Component-Renewable Energy (NC-RE)

- Transmission system built for renewables which are covered under waiver of transmission charges to be separately billed as "National Component" in the ratio of LTA+MTOA of all DICs across the Country.

- Linewise YTC for such transmission system shall be taken at "zero cost"
  - no cost implication shall be there under usage component for such system.

National Component-HVDC (NC-HVDC)

- 30% transmission charges for HVDC bipole
  - Alternative formulation -complete HVDC to Regional Component

- HVDC systems such as back to back are used for control function by system operator

- Biswanath Chariali-Agra HVDC system entire Yearly Transmission Charges and for Adani Mundra – Mohindergarh HVDC System, portion of Yearly Transmission Charges.

- To be shared by DICs of all India in the ratio of LTA+MTOA

Regional Component

- HVDC (RC-HVDC)- 70% of transmission charges of bipole HVDC Transmission System- to be shared by drawing DICs of receiving region & injecting DICs for LTA to target.
    - Example

- Static Compensator (STATCOM), Static VAR Compensator (SVC), Bus Reactors, and any other transmission element(s) identified by Central Transmission Utility being critical for providing stability, reliability and resilience in the grid - to be shared by DICs in the region in which these devices are located in the ratio of LTA+MTOA.
    - Drawing DICs
    - Injecting DICs- untied capacity

Transformers Component (TC)

- The transformers are planned as ISTS to cater to the drawal requirement of the State by the CTU. CTU to provide list of such transformers.

AC System Component (ACC)

- Includes AC transmission lines, AC substation, line and bus reactor and Inter-connecting transformers (excluding the drawl transformers which have been proposed to be shared by the State, SVCs, STATCOMs and such other devices which have been proposed to be shared by region in which they are located).

- Following parts:

(i) Usage Based Component (AC-UBC); and

(ii) Balance Component (AC-BC).

Usage Based Component

- Actual data –
  - injection / drawl for the month.
  - Lines in use

•"Peak block" for the month shall be considered as the block in which sum of ISTS drawl for all States is maximum to determine utilisation component of AC transmission charges. While identifying peak block, the injection into ISTS by a State shall be ignored .

Usage Based Component-Example for SIL

- Surge Impedance loading of standard transmission line at a nominal voltage to determine utilization percentage of a line .

    - A transmission line with SIL of 500 MW is carrying 300 MW in the Base case for Peak Block.
    - The transmission charges as per linewise transmission charges for such line is suppose Rs 100 Crore.
    - Then the transmission charges to be considered under AC-UBC for such a line shall be (300/500)*100= Rs. 60 Crore.
    - The balance Rs. 40 Crore shall be considered under AC-BC component

- Percentage usage of each transmission line to be multiplied by line-wise Monthly Transmission Charges to obtain modified line-wise transmission charges.

- Transmission charges at each node shall be calculated as per Hybrid Methodology, using modified line-wise transmission charges obtained as per clause (6) of this Regulation.

Balance Component-AC-BC

The transmission charges under AC system component after allocating the charges under ”Usage based” component –AC-UBC shall be shared as balance component –AC-BC in the ratio of Contracted capacity of LTA and MTOA .

Transmission deviation rate

- In case aggregate metered ex-bus MW injection or the aggregate metered MW drawal of a DIC, in any time block exceeds the sum of Long Term Access and Medium Term Open Access, the concerned DIC shall be charged for such deviations @ Transmission Deviation Rate

- Transmission Deviation Rate for a State shall be charged at 1.20 X (transmission charges of the State for the Billing month)/ (quantum of Long Term Access plus Medium Term Open Access of the State for the Billing month)

- Transmission Deviation Rate for generating stations and bulk consumers shall be charged @Transmission Deviation Rate for the State where the generating station or bulk consumer is located.

Transmission charges for Short Term Open Access

•No separate charges shall be levied for STOA including collective transactions.

Example

Suppose a State has LTA of 5000 MW, it schedules power under LTA as 3000 MW, schedules power under STOA as 1000 MW and under collective transaction as 1200 MW. It shall not be charged any STOA charges while scheduling 1000 MW+ 1200 MW under Short term / collective. If it draws upto 5000 MW in a block , it shall not be levied any transmission deviation charges @TDR. However if it draws 5100 MW in a block , it shall pay for 100 MW@TDR.

**Deviation shall be calculated on actual injection /drawl over LTA+MTOA of a DIC @ 1.2 *Transmission charges for the State*

Example 2

- Suppose a generating station with Installed capacity of 1200 MW has LTA of 1000 MW and firm PPA for 500 MW.
- The transmission charges corresponding to 500 MW shall be determined at drawl end.
- Suppose generator injects 800MW
  - out of which 500 MW is scheduled under long term,
  - 300 MW under STOA, it shall not pay any charges for deviations under TDR since its LTA is 1000 MW. Now if it injects 1100 MW, out of which 600 MW is under STOA and 500 under LTA, it shall pay for transmission deviation @TDR for 100 MW. This deviation is payable on actual injection and not on schedule. For example this generator has scheduled STOA for 650 MW and LTA for 500 MW, however it injects 1100 MW in a block, it shall pay for transmission deviation @ TDR only for 100 MW and not for 150 MW scheduled over LTA.

Charges for embedded entities

Scenario of (LTA+ MToA) of the State Vs Actual drawl	Deviation charges on State	Suggestion for STOA charges collection from Embedded Utilities
(LTA+MToA)≥Actual drawl	State does not pay deviation transmission charges	
(LTA+MToA)< Actual drawl of State	State pays for transmission deviation charges @TDR for drawl in excess of its LTA+MTOA.	The transmission deviation charges paid by the State may be divided among embedded entities and State based on actual charges paid by the State. Or STOA charges @ rate of TDR may be collected by the State upfront.

Transmission charges liability in case of delay of upstream or downstream system

•In case either upstream or down-stream system is not ready due to which an element cannot be put in regular service , the transmission charges for such element shall be payable by owner of upstream or downstream system which is delayed. For cases where both upstream and downstream system is delayed, transmission charges for the element shall be shared by owner of upstream and downstream system in the ratio to be decided by the Commission, Transmission licensee may approach the Commission impleading owner of upstream and downstream system.

Transmission charges liability in case of delay of generating station

•In case of delay of generating station, it shall be liable for transmission charges of Associated Transmission System i.e Yearly Transmission charges of such transmission elements which have specifically been indicated as generator‟s ATS.

•Generating stations for whose Long term Access no additional investment is required i.e there is no Associated transmission system and the Long term Access is granted on existing margins- generating station shall pay transmission charges @10% *TDR for the period of delay of the generating station.

Thank You

Generating station with PPA

- Where Generating Stations or sellers have been granted Long term Access or Medium Term Open Access and have entered into Power Purchase Agreement for supply of power under such Long Term Access or Medium Term Open Access, the transmission charges towards such Long Term Access or Medium Term Open Access shall be determined at the drawal- nodes and zone and billed to the buyer.

- Provided that sellers and buyers shall make necessary adjustment or settlement among themselves for transmission charges in terms of their respective Power Purchase Agreements

Sharing of transmission losses

•All India Average Transmission losses for ISTS shall be calculated by Implementing Agency for each week, from Monday to Sunday, as follows:

{(Sum of injection into the ISTS at regional nodes for the week) minus (Sum of drawal from the ISTS at regional nodes for the week)}/ Sum of injection into the ISTS at regional nodes for the week X 100 %

•Drawal Schedule of DICs shall be worked out as per provisions of Grid Code after taking into account the transmission losses of previous week.

•No transmission loss for ISTS shall be applicable while preparing schedule for injection node including that for Collective Transactions over the Power Exchanges.

Transmission loss

•Losses are currently determined for injection nodes as well as drawl nodes. However while scheduling losses for scheduling under long term access or medium term open access is payable by drawl entities only. Currently, the losses in ISTS are calculated regionally as total loss and it is divided by 2 to determine average loss for injection and average loss for drawl which is in approximation.

For example , if total injection into ISTS is 40000 MW and total drawal from ISTS is 39500 MW, loss is 500 MW,
Average injection loss = (500/40000)*(1/2)= 0.625%
Average drawl loss = (500/40000)*(1/2)= 0.625%

Example 4

- Suppose a generating station has PPA with a Buyer State for 500 MW. Buyer obtains LTA from generating station to buyer periphery. Suppose the buyer schedules only 300 MW from such generating station and generating station obtains STOA for 200 MW. If generating station injects 500 MW, no deviation charges shall be levied on such generating station @TDR since it is within LTA from its injection point.

Treatment of part operationalization of generator

•CTU identifies several transmission elements to operationalize LTA for a LTA customer, however only a few elements are commissioned, then CTU should operationalize LTA partly only when LTA Customer seeks such part operationalization upto its transmission capacity.

•CTU may operationalize LTA as per availability in transmission system even without availability of full ATS, if LTA customer seeks such operationalisation and vice versa.

•Where some of transmission elements of ATS have been commissioned and LTA customer has sought part or full operationalization of LTA, once the LTA for such LTA Customer is operationalized, the elements of ATS which have achieved COD with regular service shall be included in ISTS pool for recovery under Regulation 5 to Regulation 8 of Draft Sharing Regulations 2019 .

Generating station is connected to both ISTS and intra-State Transmission System

- ISTS charges and losses shall be applicable only on quantum of Long Term Access and Medium Term Open Access connected through ISTS and STU charges and losses shall not be applicable on such capacity connected through ISTS.

- Provided that this provision shall be subject to availability of adequate capacity in the intra-State Transmission System to draw allocated quantum of Long Term Access or Medium Term Access as certified by the Central Transmission Utility.

Transmission Service Agreement, Revenue Sharing Agreement and Billing Collection and Disbursement Procedure

- Relevant features of TSA, RSA and BCD Procedure have been included in the regulations including payment security mechanism, Event of default etc.

- Transmission Service Agreements and Revenue Sharing Agreeemnts as on date of commencement of these Regulations shall be saved till expiry of the Agreements to the extent they are not in conflict with provisions of 2019 Sharing Regulations as and when it becomes effective

Intra state lines certified as ISTS

- An Intra-State Transmission System already certified by the respective Regional Power Committees being used for inter-State transmission of electricity and for which tariff has already been approved by the Commission, shall be covered under these Regulations:

- Provided that such intra-State Transmission System shall be included under these Regulations only for the tariff period for which tariff has already been approved by this Commission.

Timelines

- Base case for the Billing month shall be prepared by the Implementing Agency by 15th day of the month following the Billing month.

- Payable transmission charges shall be notified by the Implementing Agency by 25th day of the month following the Billing month.

- Based on the notified allocation of charges by the Implementing Agency, Regional Power Committee Secretariat shall issue Regional Transmission Accounts by the end of the month following the Billing month.

- On or before end of the Billing Month, all entities whose assets are to be used in the Basic Network shall submit to the Implementing Agency Network data and dates of commercial operation of any new transmission asset in the Billing Month and the Yearly Transmission Charge along with circuit kilometers at each voltage level and for each conductor configuration, as approved by the Commission

- Implementing Agency shall notify, on its website, the peak block for the Billing Month on first day of the following month.

- On or before 7 (seven) days after start of Billing Month, Central Transmission Utility shall submit indicative cost for each voltage level and conductor configuration for transmission lines to the Implementing Agency.

- On or before 7(seven) days after end of Billing Month, DICs shall submit following data:
  (a) MW and MVAR Data for injection or drawal at various nodes or a group of nodes for peak block for each Billing Month.
  (b) Quantum of power tied up through PPAs for interchange of power under long term access or approved medium term open access.

Non-submission of data

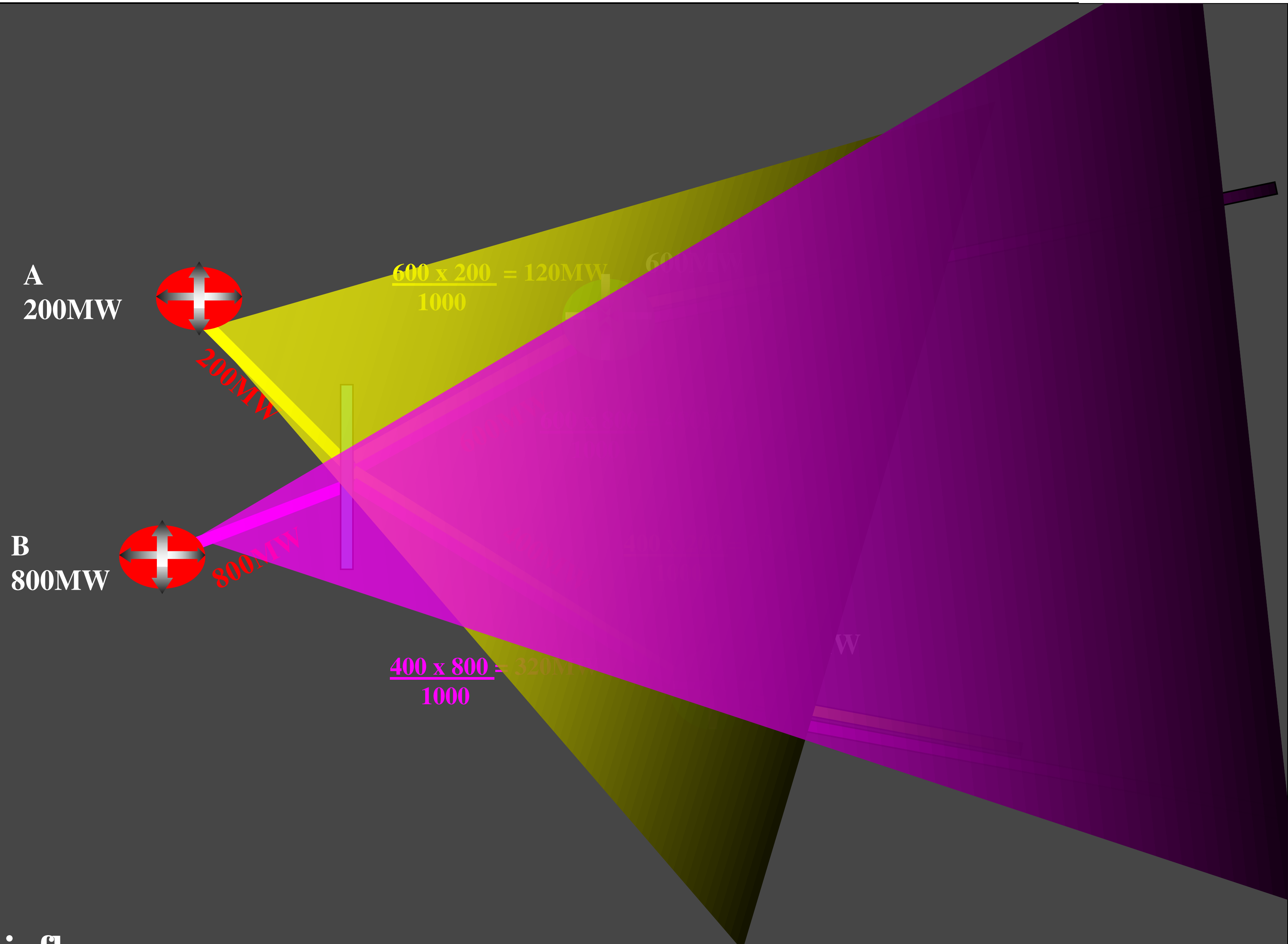
- In the event of such information as required by the Implementing Agency is not made available within the stipulated timeframe or to the level of details required, the Implementing Agency shall compute transmission charges based on such information from available sources.

- If a DIC doesnot provide the required data, including injection or drawal data for intra-State points within stipulated time period, it shall be levied an additional transmission charge @ 1% of the transmission charges under the First Bill for the month.

Example 4

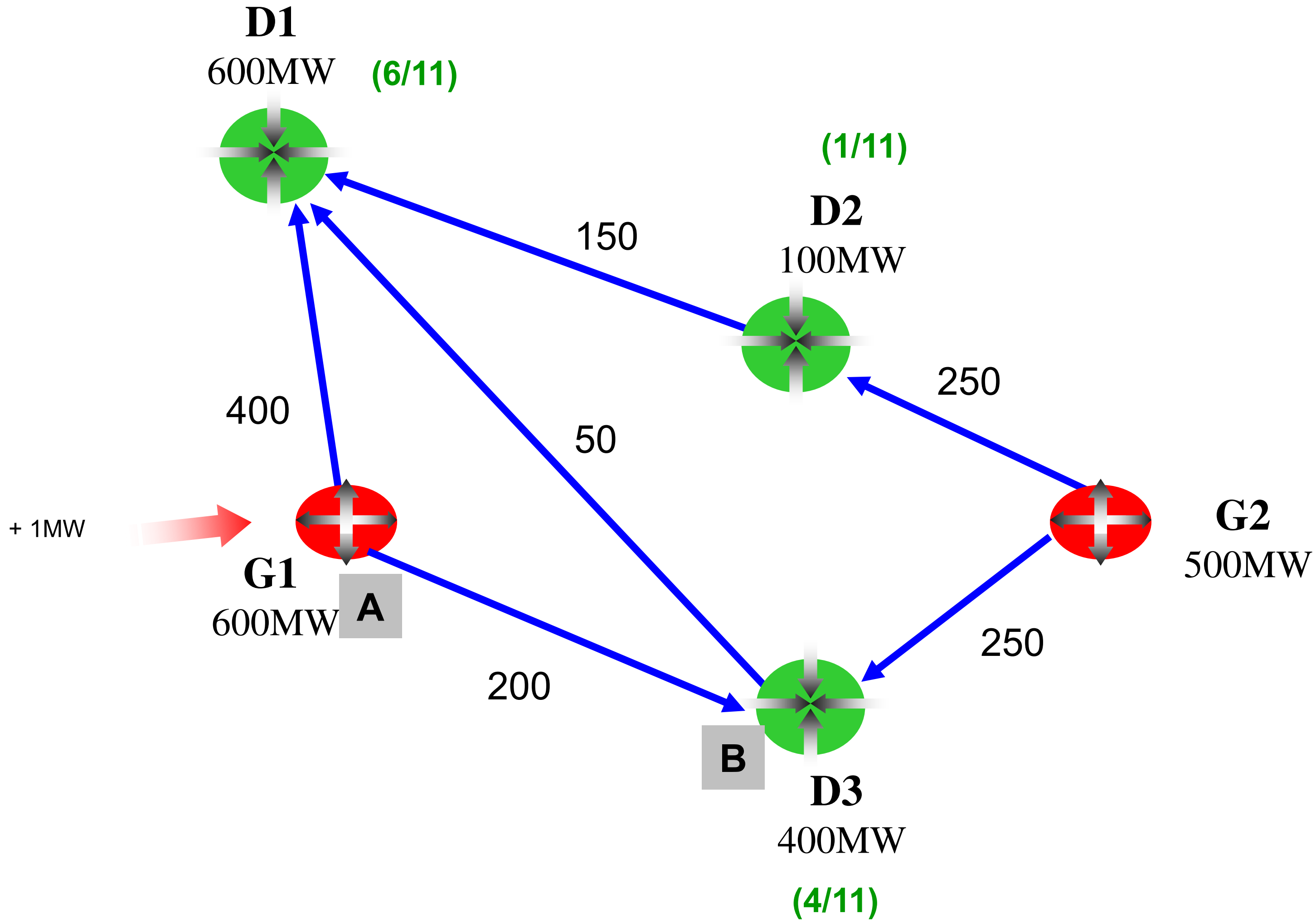
- Suppose a generating station has PPA with a Buyer State for 500 MW. Buyer obtains LTA from generating station to buyer periphery. Suppose the buyer schedules only 300 MW from such generating station and generating station obtains STOA for 200 MW. If generating station injects 500 MW, no deviation charges shall be levied on such generating station @TDR since it is within LTA from its injection point.

Average Participation



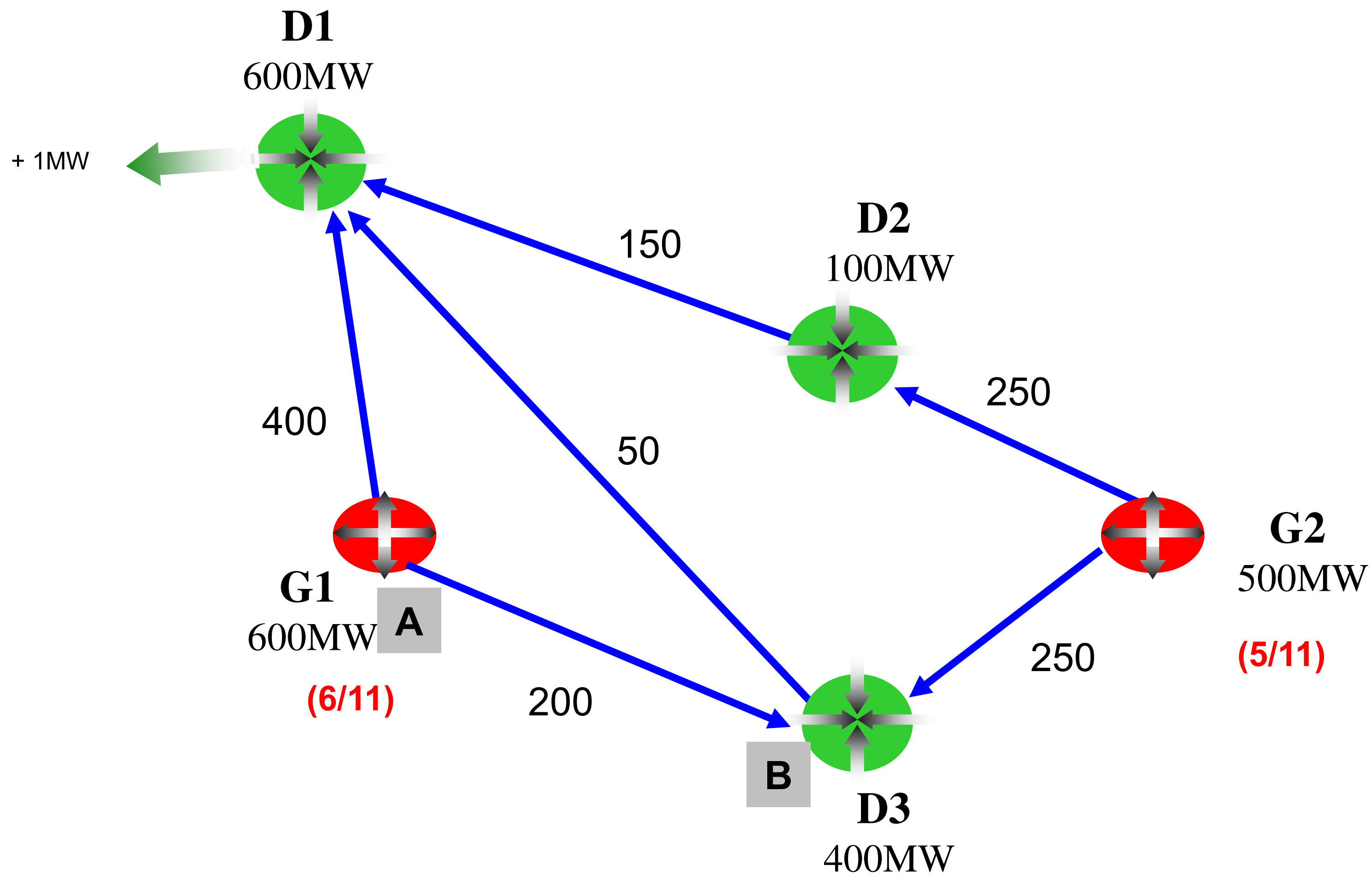
Area of influence

Marginal Participation



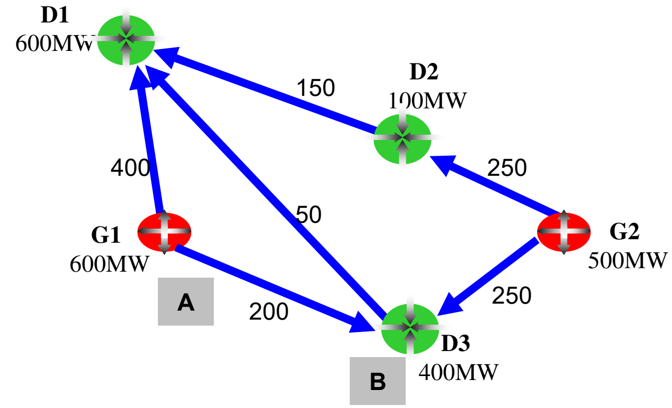
*Indicative only
Power flow in lines in MW

Marginal Participation



*Indicative only
Power flow in lines in MW

Marginal Participation



Line AB

BC + CD +EF+…

Point Tariff

Users
G1
G2
D1
D2
D3

* Identification of the slack node(s) changes the rule of the game

Anenxure-IV

Report of the
FOR STC Sub Group
on
Intra-State
Reserves and Ancillary Services
for Balancing

संतुलन
(SANTULAN)

JANUARY-2020

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केन्द्रीय विद्युत विनियामक आयोग

CENTRAL ELECTRICITY REGULATORY COMMISSION

सत्यमेव जयते

Indu Shekhar Jha
Member

के वि वि आयोग
CERC

Ensuring load-generation balance in a power system is a rigorous exercise that commences in the planning phase and ultimately culminates in real-time despatch. The mechanisms for balancing in the Indian power system with multi-area and nested control area operation philosophy are still evolving. Formation of the national synchronous grid as well as the introduction of energy markets, non-discriminatory open access in transmission and imbalance settlement mechanism are few of the major endeavors in this direction. In view of India's commitment towards renewable energy, there is an urgent need to ramp up the efforts and introduce instruments for active balancing through reserves and ancillary services along with the established mechanisms of passive balancing through tightening of the frequency band and pricing of imbalance.

The reserve regulation ancillary services operations and the pilot projects on fast response ancillary services, automatic generation control and security constrained economic despatch have provided deep insights that could be utilized to evolve such systems in the intrastate level. The report titled 'SANTULAN' prepared by the FOR standing committee sub-group, shares the practices for power system balancing prevailing in India and other large countries. It provides a roadmap for implementation of reserves and ancillary services at the intrastate level. Sincere efforts towards implementation of the recommendations of SAMAST, CABIL and SANTULAN reports would prepare a fertile ground for a vibrant and robust electricity market. This would also facilitate smooth integration of the envisaged renewables in the Indian grid.

(Indu Shekhar Jha)

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Foreword

The obligation of providing uninterrupted, quality and economic power supply to the consumers is challenging due to the inherent variability and unpredictability of the instantaneous demand for electricity, availability of generating units, availability of transmission and distribution equipment, generation output and transmission losses. High penetration of variable renewable energy sources adds to this uncertainty. Classical literature and international experience recommend maintaining adequate spinning generation reserves and dispatching them optimally for ensuring reliability. It calls for identification of the various kinds of the reserves and the attributes thereof; dimensioning of the various types of reserves; and establishment of a mechanism for ensuring availability, dispatching and settlement of the services rendered by the provider of those reserves. The definitions and prescription for deployment of reserves is evolving and every power system/market has to charter its own course.

The Indian power system has gained significant experience in this niche area through deployment of the reserve regulation ancillary services, fast response ancillary services, pilot project on automatic generation control and pilot project on security constrained economic dispatch at the national level through a regulated arrangement. The benefits accrued to the overall system have been encouraging. Such systems could be introduced at the intrastate level, provided the basic building blocks are established within the State by implementation of the recommendations of the report on 'SAMAST' and 'CABIL'. The off-line pilot project through the Solver tool inbuilt in the MS Excel, taken up by the SLDCs of Madhya Pradesh, Maharashtra and Gujarat, established that implementation is possible without unsettling the existing contracts. The pilot also revealed the potential benefits to the State system by adoption of algorithmic approach for co-optimization of energy and ancillary services. This report documents the deliberations of the sub-group constituted for the purpose and it suggests a roadmap for implementation of intrastate reserves and ancillary services in India through a regulated mechanism as a transition to a market-based system.

(S. K. Soonee)
Chairman of the sub-group

Acknowledgements

The sub-group members thank the Standing Technical Committee of the Forum of Regulators for constituting the sub-group and creating a platform for deliberating on a very forward-looking terms of reference. Special thanks to Shri. P.K. Pujari, Chairperson CERC & FOR for motivating and guiding the sub-group.

The members acknowledge the extensive support provided by their parent organizations for accomplishing the assignment. The sub-group is grateful to the management of the SLDCs/RLDCs/NLDC who hosted the various meetings of the sub-group even at short notice.

The sub-group would like to thank the FOLD secretariat as well as all the FOLD members for their contributions. It is also indebted to the rich literature by subject experts and reports of all the past committees and Task Forces. A big thanks to the load despatchers (list enclosed) across different LDCs who worked tirelessly behind the scenes.

The sub-group would like to specifically thank Shri Vivek Pandey and Shri Aditya Das from WRLDC for their assistance in assimilating all the inputs and drafting the sub-group report.

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Subgroup Chairman

Contributions

S No.	Name (Mr./Ms.)	Organization	Contributed in
1.	R.A. Sharma	SLDC Madhya Pradesh	Pilot project for Madhya Pradesh
2.	S. S. Patel	SLDC Madhya Pradesh	Pilot project for Madhya Pradesh
3.	Vivek Agrawal	SLDC Madhya Pradesh	Pilot project for Madhya Pradesh
4.	Aarif Ahmad Khan	SLDC Madhya Pradesh	Pilot project for Madhya Pradesh
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10.	K.V.N. Pawan Kumar	NLDC	Literature Survey
11	Venkateshan M.	SRLDC	Survey
12.	Sunil Kanojia	NRLDC	Survey
13.	Naga Sudhir	WRLDC	Survey
14.	Srinivas Chitturi	WRLDC	Dimensioning of Reserves

Executive Summary

"The key to keeping your balance is to know when you have lost it" – Anonymous

Adequate reserves at the disposal of system operators is a well-recognized necessity for imbalance handling and reliable operation of the power system. The National Electricity Policy (NEP) mandates creation of 5% of spinning reserve at national level for grid security and for quality power supply. The growing penetration of renewables (both wind and solar) in India has further highlighted the requirement of flexibility services and system reserves for managing the inherent intermittency and variability of these generation resources.

The reserve requirement is generally a small proportion of the aggregate demand in the system and they have to be ensured all the time through unit commitment when necessary. Reserves are normally pressed into service only for a short duration. Therefore, assessment of the optimal quantum of reserves for the randomly varying system conditions could be quite challenging. Being a niche requirement, the enabling framework for dimensioning and facilitating availability, deployment, performance evaluation and settlement of reserves is equally challenging.

The Central Commission has over the years taken several initiatives to evolve a sustainable mechanism for deployment of reserves. Subsequent to the notification of 'roadmap to operationalize reserves in the country' in Oct 2015, the commission facilitated creation of reserves at regional level through enabling norms [55% technical minimum, upper limit for scheduling, unit commitment] for flexibilization of thermal power stations. Further, reserve regulation ancillary services (RRAS), fast response ancillary services (FRAS), automatic generation control (AGC) and security constrained economic dispatch (SCED) etc. established an enabling mechanism for optimal dispatch of reserves and settlement thereof at interstate level. This report compiles the experience of ancillary services at the interstate level and provides suggestions for implementing such mechanisms at the intrastate level.

The key recommendations of the sub-group are as under:

1. Establish a robust framework in SLDC for scheduling, metering, accounting and settlement by implementing recommendations of the SAMAST report.
2. Equip the SLDCs with enabling IT infrastructure and adequate human resources by implementing recommendation of the CABIL report.
3. Notify the norms for minimum turn down level, upper scheduling limit and ramp rate for thermal generating units
4. Mandate computation and monitoring of area control error at the state periphery
5. Notify regulations on essential reliability services with following features
    a. A-priori declaration of unit/station level constraints and other details by all essential reliability service providers (viz. DC, start-up time, minimum up time, minimum down time, ramp rate, energy charge rate etc.)
    b. Periodic assessment of the required reserves
    c. Monitor availability of reserves in real-time and ensure its adequacy through unit commitment over a rolling window.
    d. Specify the criteria for deployment of reserves by SLDC
    e. Adopt a suitable algorithm for optimization of reserves despatch
    f. Create an intrastate virtual ancillary entity to act as a counterparty for scheduling
    g. Suitable compensation mechanism for flexibility / ancillary service providers
    h. Separate regulatory pool account for collection and disbursement of charges related with essential reliability services
6. Suitable mechanism for arranging reserves competitively could be evolved gradually.

A methodology for dimensioning reserves has been suggested. The report documents the pilot project for co-optimization of energy and reserves dispatch in Madhya Pradesh, Maharashtra and Gujarat. A model regulation has also been drafted and the same could be moderated for different States. The report also suggests a roadmap for implementation.

1. Introduction

"We are all tasked to balance and optimize ourselves"

1.1. Formation of the sub-group

In the 22nd meeting of the standing technical committee of the Forum of Regulators (FOR) for implementation of Framework on Renewables at the State level, held on 1st November 2018, it was decided to constitute a sub-group for working on harnessing reserves at state level with appropriate settlement mechanisms. The sub-group comprises of the following members:

1. Sh. S.K Soonee, Advisor, POSOCO - Chairman of the sub-group
2. Sh. P.J. Thakkar, Member (T), GERC (Gujarat) - Member
3. Sh. Prafulla Varhade, Director (EE), MERC (Maharashtra) - Member
4. Sh. Gajendra Tiwari, Director (Tariff), MPERC (Madhya Pradesh) - Member
5. Sh. Umakanta Panda, Secretary, TSERC (Telangana) - Member
6. Sh. B.B. Mehta, Chief Engineer, SLDC Gujarat - Member
7. Sh. Anil Kolap, Chief Engineer, SLDC Maharashtra - Member
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9. Sh. P. Suresh Babu SE, SLDC Telangana - Member
10. Sh. V. K. Shrivastava, Executive Director, WRLDC - Member
11. Sh. Abhimanyu Gartia, Executive Director, SRLDC - Member
12. Sh. S.C. Saxena, General Manager, NLDC - Member
13. Sh. Ravindra Kadam, Advisor (RE), CERC - Member/Convener

Co-opted members:

14. Dr. Sushanta Chatterjee, Chief (Reg. Affairs), CERC
15. Prof. Abhijit Abhyankar, IIT Delhi

Special invitee: K.C.V. Ramanjaneyalu, SLDC Karnataka

1.2. Terms of reference of the sub group

The terms of reference of the sub-group were as under:

a) To disseminate the learning from the experience of implementing the reserve regulation ancillary services and fast response ancillary services at the interstate level and recommend the roadmap for implementing similar mechanisms at the state level.

b) To recommend the model regulations for harnessing the flexibility attributes, maintaining the mandated reserves and deploying them under normal and contingent scenario through intra-state reserve regulation ancillary services.

c) Any other recommendation as deemed fit in the context.

The FOR letter regarding constitution of the sub-group and the terms of reference of the sub-group is enclosed as **Annex-I**.

1.3. Methodology

The sub-group conducted physical meetings as well as interactions through video conferencing during April – December 2019 to deliberate on different issues in line with the terms of reference. Those interactions have been listed below. A consolidation of the discussion summary of the meetings is given as **Annex-II**.

Table 1: Sub-group meetings and other interactions

Meeting number	Date	Venue
1	6-May-19	NLDC New Delhi
2	7-Jun-19	SLDC Vadodara, Gujarat
3	26-Jul-19	SLDC Jabalpur, MP
4	30-Aug-19	SLDC Maharashtra
5	31-Oct-19	SRLDC, Bengaluru
6	26-Nov-19	Discussion in FOLD (Through VC)
7	31-Dec-19	Discussions through VC

The sub-group visited four SLDCs and interacted with the personnel working in the area of scheduling, IT, accounting & settlement etc. to understand the existing framework and capabilities. The report of the various expert committees on the subject as well as the prevailing CERC regulations and orders on ancillary services, automatic generation control and security constrained economic dispatch were studied. The sub-group organized online surveys to assess the availability of the basic building blocks for implementation of reserves and ancillary services at state level.

The following aspects were deliberated by the sub-group:

(1) What is the need for intrastate ancillary services?
(2) How is imbalance by intrastate entities handled by the SLDC?
(3) How is imbalance settled within the state?
(4) What are the essential reliability services in the Indian context?
(5) What are the learnings from implementation of RRAS at the regional level?
(6) What are the prevailing methodologies for reserve assessment in the State?
(7) What are the prevailing methodologies for unit commitment in the State?
(8) What are intrastate reserves and ancillary services?
(9) Are the interstate reserves different from intrastate reserves?
(10) Which generators could be eligible for participation in the intrastate ancillary services?
(11) How much reserve should be maintained within the State?
(12) How to assess the available reserve margins in intrastate generators?
(13) How to establish the scheduling limits for intrastate generators?
(14) How to assess the available spinning reserve in the State?
(15) How can the operator visualize the available reserve in the intrastate generators?

(16) How to despatch the available intrastate reserves to regulate deviations from schedule?
(17) How to compensate the generators for delivery of ancillary services?
(18) How to recover the cost of despatched reserves?
(19) Should there be any incentive to generators for providing reserves?
(20) How to replenish the depleted reserves?

Literature survey of the international practices was carried out.

Several interactive sessions for capacity building were conducted for rolling out pilots on reserves and ancillary services. The following table summarizes such programs & interactions:

Table 2: Capacity building initiatives

SN	Date	Description	Remarks
1	25-30 Jun 2019	Interaction between WRLDC & SLDC Gujarat on optimization techniques	Teleconference
2	15-20 Jul 2019	Interaction between WRLDC & SLDC MP on optimization techniques	Teleconference
3	7-Aug-2019	Interaction between SLDC Kalwa & WRLDC on scheduling & Optimization	at WRLDC Mumbai
4	13-Aug-2019	Interaction between SLDC Kalwa & WRLDC on scheduling & Optimization	at WRLDC Mumbai
5	19-21 Sep 2019	Capacity building program on '*Implementation of Optimization Techniques for Indian Power System Operation*' (in collaboration with IIT-Delhi & NLDC)	at NLDC New Delhi

A summary of the capacity building program is attached as **Annex-III**.

The demo of the existing IT infrastructure at NLDC, created for implementation of RRAS, FRAS and SCED was seen. Pilot project were taken up for three RE rich states of Madhya Pradesh, Gujarat and Maharashtra. Algorithm was developed in MS Excel for dispatching reserves in different scenarios. Summary is compiled as **Annex-V, VI and VII** respectively.

The draft recommendations of the sub-group were presented in the FOLD meeting on 26th Nov 2019. The draft report was circulated among members and the recommendations were finalized during the meeting on 31st December 2019.

2. Ancillary Services – International Practices

"To go beyond is as wrong as to fall short" – Confucius

2.1. Ancillary services- definition and deployment

Ancillary services support grid reliability, security and to a large extent power quality. Ancillary Services may include a number of different operations such as frequency support, voltage support, and system restoration. However, there is no universal approach or definition of ancillary services. Rather specification of services and the design of the ancillary service arrangements vary depending upon the overall market design and the technical characteristics of the power system. The definition of Ancillary Services as given by Eric Hirst and Brendon Kirby is "*Ancillary services are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery*."

2.2. Range of ancillary services in other countries

Federal Electricity Regulatory Commission of United States vide its Order no. 888 approved the following six ancillary services to be included in the open access transmission tariff

- Scheduling, system control and dispatch
- Reactive supply and voltage control
- Regulation and frequency response
- Energy imbalance service
- Spinning reserves
- Supplemental reserves

The various ancillary services deployed by the Independent System Operators in the United States are tabulated below Source: https://publications.anl.gov/anlpubs/2016/01/124217.pdf

In the c**ontinental Europe** the frequency is maintained within the range with the combined efforts of all the TSOs and obligation to have reserves. Reserves are of the following types:

i. Frequency Containment Reserve (FCR) similar to primary control
ii. Frequency restoration Reserves (FRR) similar to secondary control through AGC
iii. Restoration Reserves (RR) to replace FRR similar to tertiary control

The ancillary services available through the **Great Britain** system operation are listed below:

i. Mandatory Frequency Response
ii. Commercial Frequency Response
iii. Reserve
iv. Reactive Power
v. Black start
vi. Demand turn up

vii. Intertrip

Table 3: List of ancillary services in ISOs of United States

	Spinning Reserves	Non-spinning Reserves	Regulation
CAISO	Spinning	Non-spinning	Regulation-up Regulation-down Regulation Mileage-up Regulation Mileage-down
ERCOT	Responsive	Non-spinning	Regulation-up Regulation-down
ISO-NE	Ten-minute Synchronized	Ten-minute Non-synchronized Thirty-minute Operating	Regulation
MISO	Spinning	Supplemental	Regulation
NYISO	Ten-minute Spinning Thirty-minute Spinning	Ten-minute Non-synchronized Thirty-minute Non-synchronized	Regulation
PJM	Synchronized	Primary	Regulation
SPP	Spinning	Supplemental	Regulation-up Regulation-down

The types of ancillary services provided in the **Brazilian** Interconnected power system are:

i. Primary and Secondary frequency control
ii. Primary and Secondary power reserve
iii. Prompt reserve
iv. Reactive power support
v. Black start
vi. Special Protection System (SPS)

The various ancillary services in the **Australian** National Electricity Market are as under:

i. Frequency Control Ancillary Services (FCAS)
ii. Network Control Ancillary Services (NCAS)
iii. System Restart Ancillary Services (SRAS)

The mechanisms used for procurement of ancillary services as well as allocation and recovery of costs of procuring each ancillary service also varies from country to country. Some of the services could be mandated as non-remunerative obligations while others could be procured. "Winning bids for energy and ancillary services are mutually exclusive, but a generator can be compensated for both generation and ancillary service provision in the same period as long as the capacities allocated to each do not overlap." Source: https://publications.anl.gov/anlpubs/2016/01/124217.pdf

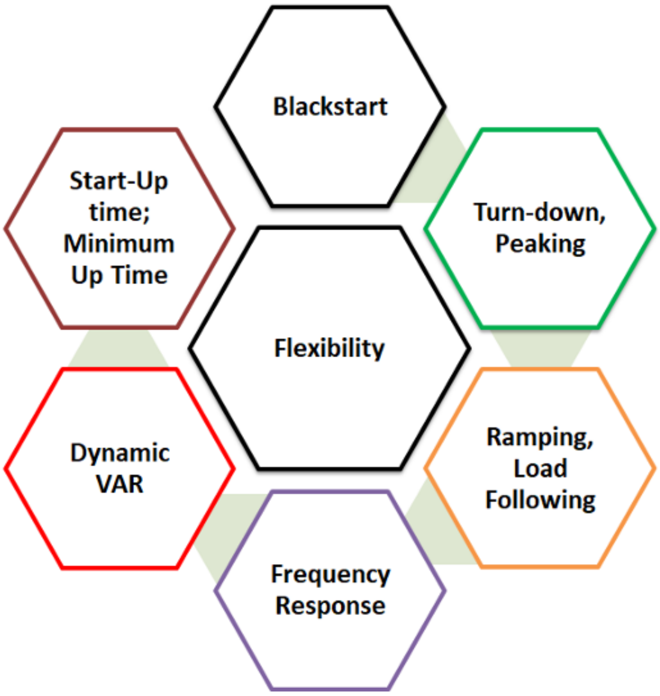


Figure 1: Flexibility attributes

2.3. Essential Reliability Services

The Ancillary Services are more generically termed as Essential Reliability Services (ERS). They are classified into following three categories:

i. Frequency support
ii. Ramping and balancing
iii. Voltage support

Sufficient level of ERS needs to be maintained through a mixture of technological, market, and regulatory approaches.

2.3.1. Frequency support

Immediately after a contingency event (e.g., a generator trip), the kinetic energy is drawn from all remaining synchronous machines to maintain the power balance between production (that has changed due to the generator trip) and consumption (that still remains the same). This withdrawal of kinetic energy is called the synchronous inertial response. As stored kinetic energy is drawn from the generators, they slow down and system frequency therefore declines. Reserves are required to arrest the frequency decline and restore it to the nominal value. Reserves for frequency support are of three types – primary, secondary and tertiary. Primary reserve responds to frequency signals, typically, within 5-10 seconds and ramp up to its full output in 30-60 seconds. Primary reserves aim at stabilizing the system frequency post contingency. The secondary reserves are automatic or deployed online by the system operator to relieve the primary response. Secondary reserves respond in 30-60 seconds and typically take

5-10 minutes to ramp up to its full output. Tertiary reserve has the task of relieving the secondary reserves and are deployed manually. Typically, tertiary reserves respond in 10-15 minutes.
The initial rate at which system frequency declines depends on the amount of inertial response (stored kinetic energy in rotational mass) available at the time of the event, (i.e., the number and size of generators and motors synchronized with the system). With the growing penetration of non-synchronous generators in the grid the system inertia would decline.

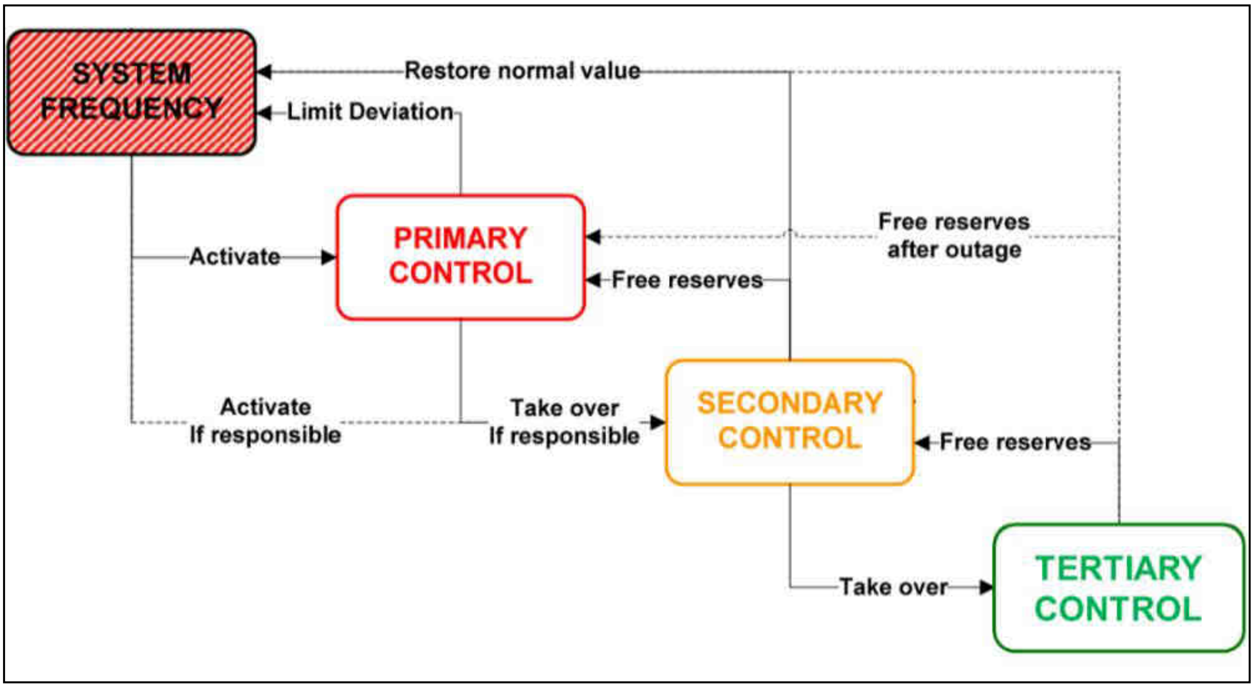


Figure 2: Schematic activation and deployment of reserves (frequency support)

As per the NERC white paper on Essential Reliability Services Sufficiency guideline, published in Dec 2016, the impact of low system inertia could be mitigated by following the alternatives:

i. *Committing additional units for their synchronous inertia, committing different units that have higher inertia, and/or using synchronous condensers*
ii. *Slow down the rate of change of frequency by increasing the rate of primary frequency response of the system in MW/s per Hz*
iii. *Slow down the rate of change of frequency by increasing the speed of frequency response, such as by adding fast frequency response from load resources, storage, synthetic inertia from wind generation, and so forth*

Another approach could be to reduce the magnitude of largest single contingency on the system through re-dispatch.
The report titled 'A survey of definitions and specifications of reserves services' by Yann Rebours and Daniel Kirschen, distinguishes between the attributes of primary, secondary and tertiary control as given in the table below:

Table 4: Attributes of reserves and its deployment

	Primary Control	Secondary Control	Tertiary Control
Why is this control used?	To stabilise the frequency in case of any imbalance	To bring back the frequency	To restore the secondary control reserve, to manage eventual congestions
How is this achieved?	Automatically		Manually
Where is this control performed?	Locally	Centrally	
Who sends the control signal to the source of reserve?	Local sensor	System Operator	System Operator
When is this control activated?	Immediately	Depends on the system	
What sources of reserves can be used?	Partially loaded units, loads, fast-starting units		

Source: [https://labs.ece.uw.edu/real/Library/Reports/Survey_of_Reserve_Services.pdf]

2.3.2. Voltage control

Basic voltage control service is an intrinsic part of power system operation. It is a compulsory provision in most of the countries. However, in few countries voltage control services by operation of generators in synchronous condenser mode are procured either through bilateral contracts or tendering process. The service providers are compensated for reactive energy production or absorption.

2.3.3. Ramping

California Independent System Operator (CAISO) in the United States was among the first independent system operators in North America to implement a separate flexibility ramping product. In November 2016, CAISO implemented flexible ramp up and flexible ramp down ancillary service market products to procure ramp-up and ramp-down capability for 15 minute and 5-minute time intervals. The product is procured in terms of megawatts (MW) of ramping required in a 5 min duration, and any resource capable of fulfilling the ramping requirement can participate. Market participants do not provide bids for this product but are instead compensated according to their lost opportunity cost of providing other services in the ancillary service market.

2.3.4. Types of procurement and remuneration methods

As per the paper “A Survey of Frequency and Voltage Control Ancillary Services- PartII: Economic features” by Rebours, et al., internationally there are four procurement methods to acquire ancillary services: compulsory provision, bilateral contracts, tendering and spot market. Each of these methods have their pros and cons. Remuneration could be according to one of the three types of price: a regulated price, a pay as bid price or a common clearing price. Remuneration for an ancillary service may combine several components that are intended to reflect the various costs that a provider of ancillary services may incur. These components include a fixed allowance (for fixed cost compensation), a utilization frequency price (for actual energy delivery), and a compensation for a possible opportunity cost.

3. Ancillary Services in India

"*Life is like riding a bicycle. To keep your balance, you must keep moving*"- Albert Einstein

3.1. Regulatory provisions for ancillary services in India

CERC Indian Electricity Grid Code Regulations, 2010 (IEGC) define Ancillary Services as below:

"…Regulation 2(1) (b)

Ancillary Services" means in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, e.g. active power support for load following, reactive power support, black start etc.;…"

The distinction between the basic services and ancillary services have been deliberated in detail In the Appeal number 202 of 2005 on a reference dated 13th day of December 2006 the Judicial Member of the Appellate Tribunal for Electricity. [Source: http://aptel.gov.in/judgements/Judgment%20-%20Appeal%20No.%20202%2005(dec).pdf] Few of the relevant extracts are quoted below:

Quote

"30… *Basic - Services" are generation, energy supply and power delivery. Ancillary services are those functions performed to support the basic services of generation, transmission, energy supply and power delivery. Ancillary services are required for the reliable operation of the power system. Automatic generation reserve (spinning and stand-by) load flowing, voltage control and black start capability are some of the commonly recognized, ancillary services. The generators typically provided these ancillary services but it is for a price, either to be agreed or auctioned in a competitive market, as exist in various other countries*."

"*32. Ancillary Services, plainly mean, are those functions performed to support the basic services of generating capacity, energy supply and power delivery. The Ancillary services are split up into different services, e.g. active reserve, reactive reserve and system re-start. Such ancillary services are required for the reliable operation of the power system. The "ancillary services" generally refer to power system services other than the provisions of energy. To be more specific, ancillary services are those functions performed by equipment and people that generate, control, transmit and distribute electricity to support basic services of generation, transmission and distribution."*

"40. …"Spinning reserve" is the ability of an online generator (load) to increase (decrease) its output (consumption) in a short period of time. In the Grid code "Spinning Reserve" has been described as "Part loaded generating capacity with some reserve margin that is synchronized to the system and is ready to provide increased generation at short notice pursuant to dispatch instruction or instantaneously in response to a frequency drop."

"43. The said author's definition of Spinning Reserve reads thus: "the spinning reserve is the unused capacity which can be activated on decision of the system operator and which is provided by devices which are synchronized to the network and able to affect the active power".
Unquote

CERC Indian Electricity Grid Code Regulations, 2010 (IEGC) mandates charges for VAR exchanges with the interstate grid as under:

Regulation 6.6 (1):

"The Regional Entity except Generating Stations pays for VAr drawal when voltage at the metering point is below 97%. The Regional Entity except Generating Stations gets paid for VAr return when voltage is below 97%. The Regional Entity except Generating Stations gets paid for VAr drawal when voltage is above103%. The Regional Entity except Generating Stations pays for VAr return when voltage is above 103%."

Regulation 6.6 (2)

"The charge for VArh shall be at the rate of 10 paise/kVArh w.e.f. 1.4.2010, and this will be applicable between the Regional Entity, except Generating Stations, and the regional pool account for VAr interchanges. This rate shall be escalated at 0.5paise/kVArh per year thereafter, unless otherwise revised by the Commission."

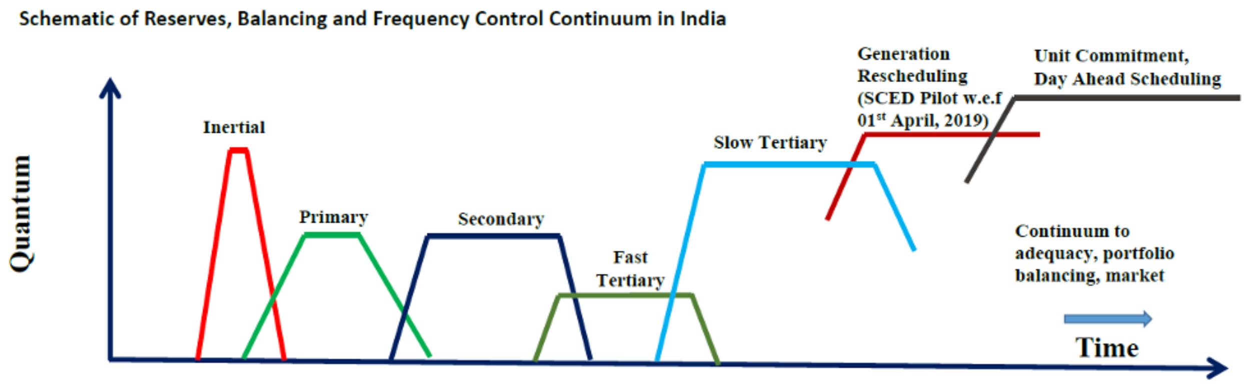
Regulation 6.6 (6):

"The ISGS and other generating stations connected to regional grid shall generate/absorb reactive power as per instructions of RLDC, within capability limits of the respective generating units, that is without sacrificing on the active generation required at that time. No payments shall be made to the generating companies for such VAr generation/absorption."

3.2. Frequency continuum in the Indian context

The report of the expert group formed by CERC to review and suggest measures for bringing power system operation closer to National Reference Frequency (Volume-I), states that "Frequency Control in any power system is basically a continuum starting from seconds to a time period of less than an hour. Beyond this time horizon, the problem is basically one of forecasting, unit commitment, scheduling and despatch. Large imperfections in this area would lead to off-nominal frequency or a large quantum of generation reserves requirement which may be suboptimal." The report of the expert group recommends the following frequency continuum.

IEGC 5.2 (f), (g), (h), (i) mandates that all coal fired units of capacity 200 MW and above, gas turbines 50 MW and hydro units of 25 MW and above shall provide primary frequency response. The salient features of reserve regulation ancillary services for slow and fast ancillary services as well as secondary control through Automatic generation control are described in the following sections.



Response → ↓ Attribute	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC/RLDC	NLDC	NLDC/SLDC	RLDC / SLDC	RLDC / SLDC
Manual /Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	CERC Order Pan-India AGC	CERC Order on FRAS Pilot	RRAS Regulations	IEGC; CERC Order Pilot on SCED upto 31st March, 2020	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Pilot 5 plants	Pilot 19 plants	Existing	Existing	Existing

Figure 3: Frequency continuum

3.3. Evolution of Ancillary services in India

CERC (Unscheduled Interchange) Regulations, 2009 mandated NLDC to provide Ancillary Services. In this direction, in 2010, an Approach Paper on Ancillary Services in Indian Context was submitted by National Load Despatch Centre to CERC.

The approach paper proposed three major categories of Ancillary Services namely

i. Load Generation Balancing Service
ii. Network Control Ancillary Services
iii. System Restart Ancillary Services

The paper recommended the use of un-despatched generation in the form of un-requisitioned surplus (URS). Also, utilization of peaking gas power plants and pumped storage hydro generating stations was envisaged for providing load generation balancing service as well as power flow control. Further, the use of hydro stations as synchronous condenser for providing reactive power support and introduction of black start as an ancillary service for hydro, gas and combined cycle stations which have black start capability was deliberated. In March 2012, CERC Central Advisory Committee (CAC) expressed the need for introduction of ancillary services in India for better security and reliability of grid operation, after due deliberation amongst the stakeholders. A national level workshop was organized in June, 2012 by the Forum of Load Despatchers (FOLD) to explain the various aspects of ancillary services mechanism in Indian context to the stakeholders.

In 2013, CERC floated staff paper on “Introduction of Ancillary Services in Indian Electricity Market”. The staff paper discussed about the types of Ancillary Services such as

i. the real power support services or Frequency Support Ancillary Services/ Load following,
ii. Voltage or reactive power support services
iii. Black start support services.

It was envisaged that the generators having surplus capacity, (i.e. either un-requisitioned surplus capacity by the beneficiaries of that capacity or generators who could not sell their capacity in the market and/or surplus captive capacity) may be allowed to bid into the power exchange, in a separate market segment. Pursuant to above, CERC floated draft Regulation on Ancillary Service operation in May, 2015. Some apprehensions were raised by the stakeholders regarding triggering criteria, eligibility of generators, minimum dispatch certainty, pricing considerations, payment security mechanism and incentive & penal provisions etc. There were also reservations from state utilities on implementation of Ancillary Services with the major concern being that it would lead to operation of costly plants leading to rise in electricity prices. After stakeholder consultations, CERC decided that, in order to meet current requirement, tertiary frequency control through utilization of un-despatched surplus capacity available in generating stations at the inter-state level, whose tariff is determined/adopted by CERC, may be introduced as Reserve Regulation Ancillary Service (RRAS) with the following approach.

a. Variable cost of RRAS provider will be considered for merit order despatch.
b. Both fixed charges and variable charges are to be paid to the RRAS providers, which in turn refunds the fixed charges to the original beneficiary in proportion to the power surrendered.
c. The refund of fixed charges to the beneficiary(ies) and mark-up paid to the RRAS provider act as an incentive for the beneficiaries and the RRAS providers respectively.

Ministry of Power, Government of India constituted Technical Committee on large scale integration of renewable energy, need for balancing, deviation settlement mechanism and other associated issues. The Committee in its report also recommended that ancillary services need to be put in place as they provide a framework for operationalizing the spinning reserves, address congestion management issues and facilitate optimization at Regional and National Level and thereby facilitate integration of renewables too. Tariff Policy amended in January 2016, which also envisaged implementation of ancillary services.

CERC (Ancillary Services Operations) Regulations were notified on 13th August, 2015. CERC, in February, 2016, set the mark-up for participation in Regulation ‘Up’ RRAS at 50 paise/kWh. The detailed procedures were also approved by CERC. Thus, with active support provided by way of policy initiatives by the Ministry of Power and the requisite regulatory framework by CERC, the

Ancillary Services were launched by the Nodal Agency i.e. NLDC in coordination with RLDCs on 12th April, 2016.

3.4. Salient features of Reserve Regulation Ancillary Services

The salient features of Reserve Regulation Ancillary Services in India are as follows:

i. All the generators, that are regional entities, and whose tariff for the full capacity is determined or adopted by the CERC have been mandated to provide ancillary services as RRAS Providers.

ii. NLDC, through the RLDCs, has been designated as the nodal agency for ancillary services operations. The nodal agency prepares the merit order stack based on the variable cost of generation.

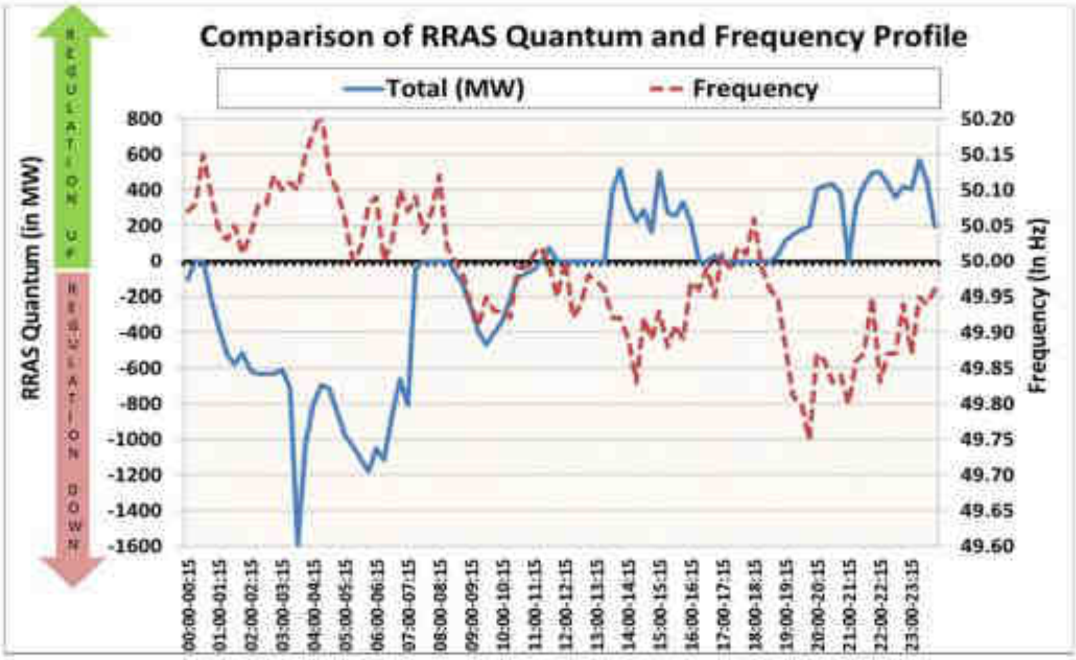


Figure 4: Typical RRAS despatch vs frequency

iii. The triggering events for ancillary services despatch have been defined in the regulations such as extreme weather /special day, generating unit or transmission line outages, trend of load met and frequency, any abnormal event such as outage of hydro generating units due to silt etc., excessive loop flows, trend of computed Area Control Error (ACE) at regional level, and recall by the original beneficiary.

iv. A "Virtual Ancillary Entity (VAE)" has been created in the respective Regional Pool for scheduling and accounting. The quantum of RRAS instruction, by the nodal agency, is being directly incorporated in the schedule of RRAS providers.

v. The RRAS instruction is scheduled to the VAE in one or more regional grids. The deviation in schedule of the RRAS Providers, beyond the revised schedule, is being settled as per the CERC Deviation Settlement Mechanism (DSM) Regulations. The energy despatched under RRAS is deemed delivered ex-bus.

vi. Nodal Agency directs the RRAS Provider to withdraw RRAS, on being satisfied, that the circumstances leading to triggering of RRAS Services have been normalized.

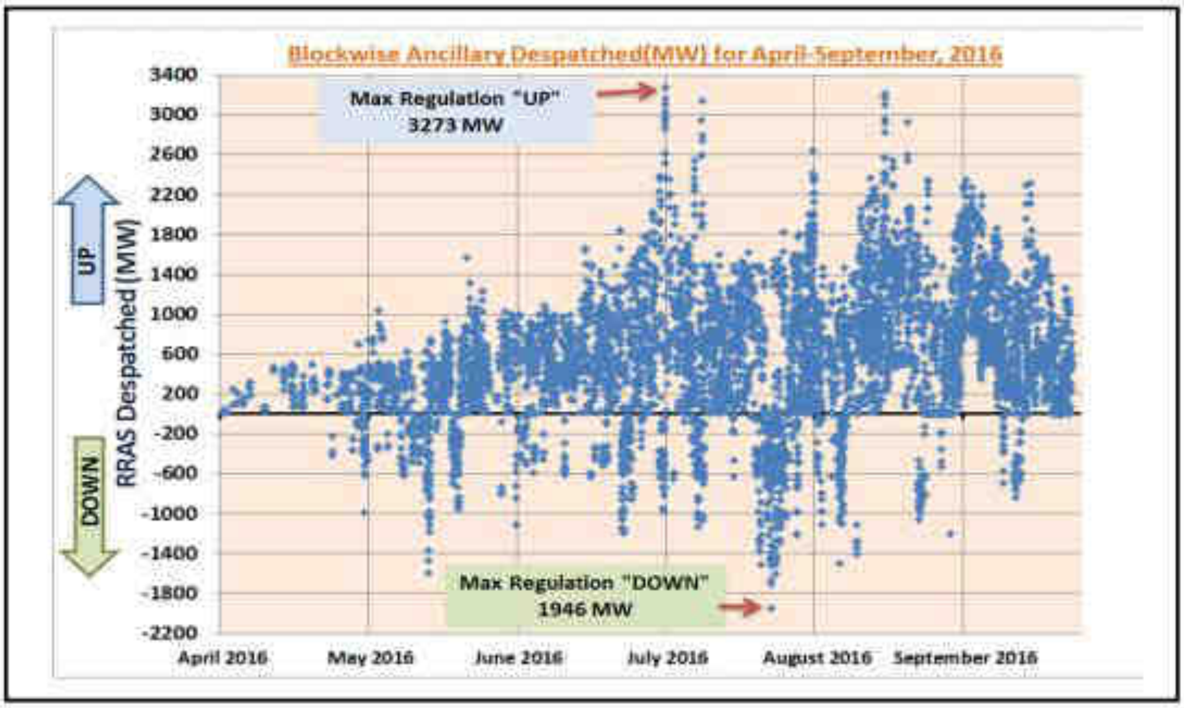


Figure 5: Typical quantum of RRAS despatch

vii. The RRAS Energy Accounting is being done by the respective Regional Power Committee (RPC) on weekly basis along with DSM Account, based on interface meters data and schedule. A separate RRAS statement is being issued by RPC along with Regional DSM Account. Any post-facto revision in rates/charges by RRAS providers is not permitted.

viii. In case of RRAS Up, fixed and variable charges are payable to the RRAS providers from the pool. In case of RRAS Down, 75 percent of the vvariable charges are payable by RRAS providers to the pool and the fixed charges are reimbursed by RRAS providers to the original beneficiaries.

ix. No commitment charges are payable to the RRAS providers. There are penalties for sustained failure to provide RRAS and violation of directions of RLDC.

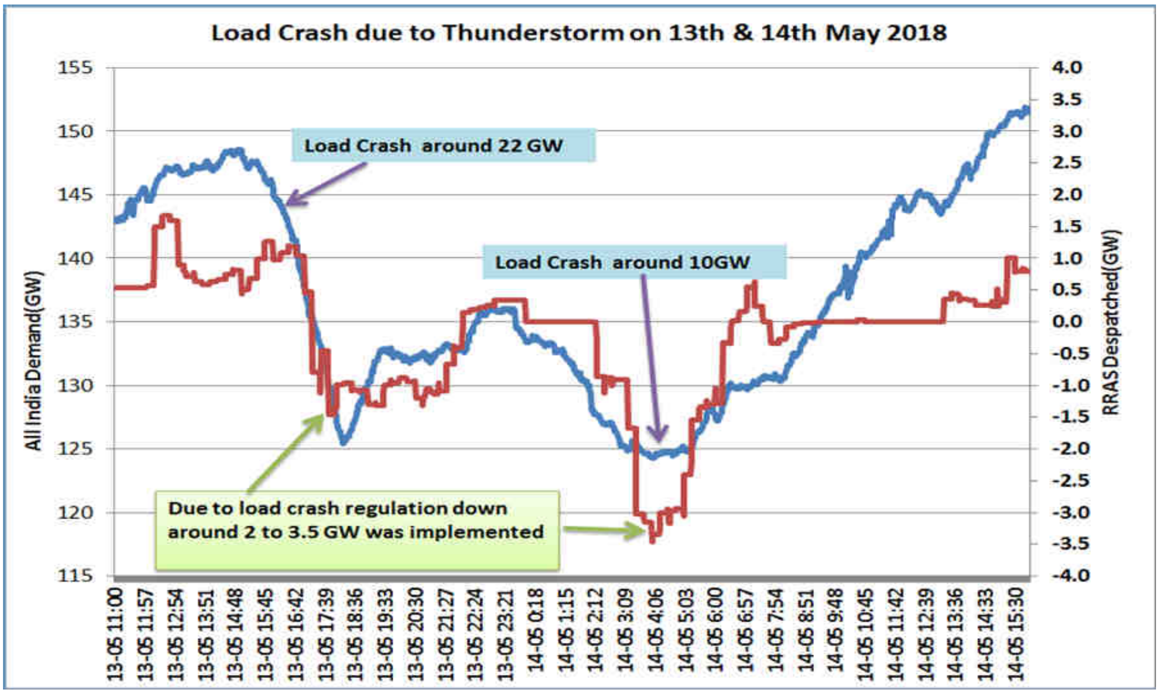


Figure 6: Typical RRAS dispatch during load crash

3.5. Salient features of Fast Response Ancillary Services

RRAS is primarily a framework for slow tertiary reserves at the ISTS level operationalized by National Load Despatch Centre (NLDC) in coordination with Regional Load Despatch Centres (RLDCs). However considering the requirement to mobilise the flexibility rendered by hydro generators viz. overload capability, fast ramping & peaking support etc. Fast Response Ancillary Services for 'regulation service' from storage/pondage based hydro stations (e.g. to handle the hour boundary frequency spikes) were conceptualized and implemented. The following attributes of hydro generation were considered for FRAS design:

i. Hydro stations are "energy limited resources" unlike the thermal stations (coal based) which are "ramp limited resources"
ii. Hydro stations are subject to limitations/constraints in terms of water inflows as well as the quantum of water that can be released based on reasons other than power generation requirements
iii. The marginal cost for hydro generation is 'zero' and the segregation of fixed and variable charges in case of hydro is only notional.

Accordingly, the Commission vide order in Petition No. 07/SM/2018 (Suo-Motu) dated 16th July, 2018 directed the implementation of pilot project for FRAS covering all Regional Entity hydro generating stations. FRAS was implemented from 26th Nov 2018 to 26th May 2019 on pilot basis. Report was submitted by NLDC to CERC on 30th July 2019 which may accessed at https://posoco.in/wp-content/uploads/2019/08/POSOCO_FRAS_Feedback.pdf.

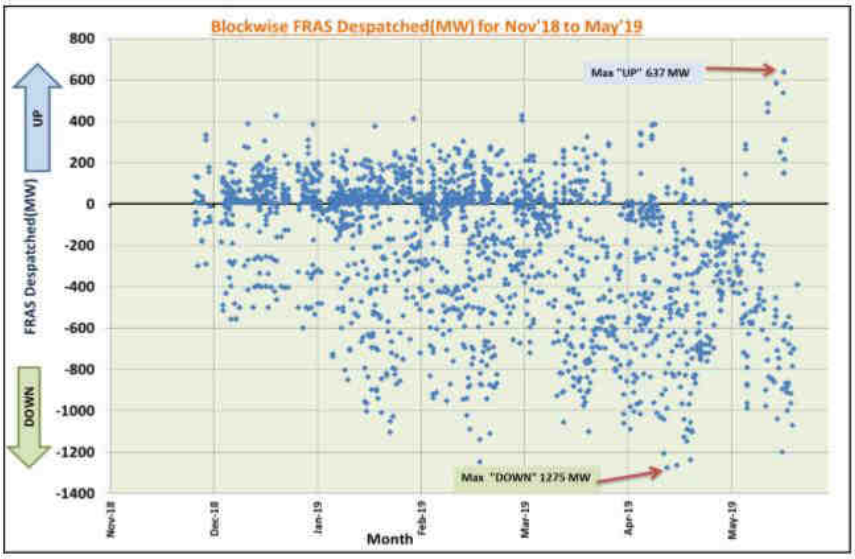


Figure 7: FRAS despatched (Nov-18 to May-19)

The salient features of FRAS were as follows:

i. All constraints declared by the hydro stations are honored. The total energy delivered over the day is maintained as far as possible, as declared by the respective hydro station.

ii. The total energy dispatched under FRAS is attempted to be squared off within the day.

iii. FRAS instructions are triggered based on a stack prepared based on the balance energy available in the hydro station.

iv. The schedules of the beneficiaries are not disturbed in the despatch of FRAS.

v. The respective RPCs issue weekly FRAS accounts along with the RRAS accounts based on the data provided to them by the RLDCs/NLDC.

vi. Incentive is paid from the DSM Pool on mileage basis at the rate of 10 paise per kWh both for 'up' and 'down' regulation provided by the hydro station.

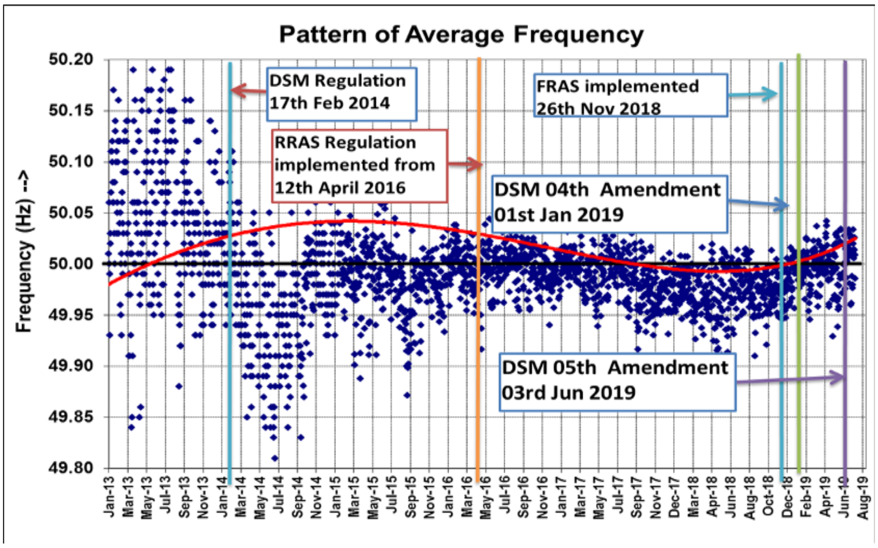


Figure 8: Improvement in frequency profile

3.6. Experience of RRAS and FRAS

Since inception till May, 2019, about 11.6 BU was despatched in Regulation Up (9767 Nos. of instructions) and about 1.4BU in Regulation down (2607 Nos. of instructions) from NLDC through RLDCs.

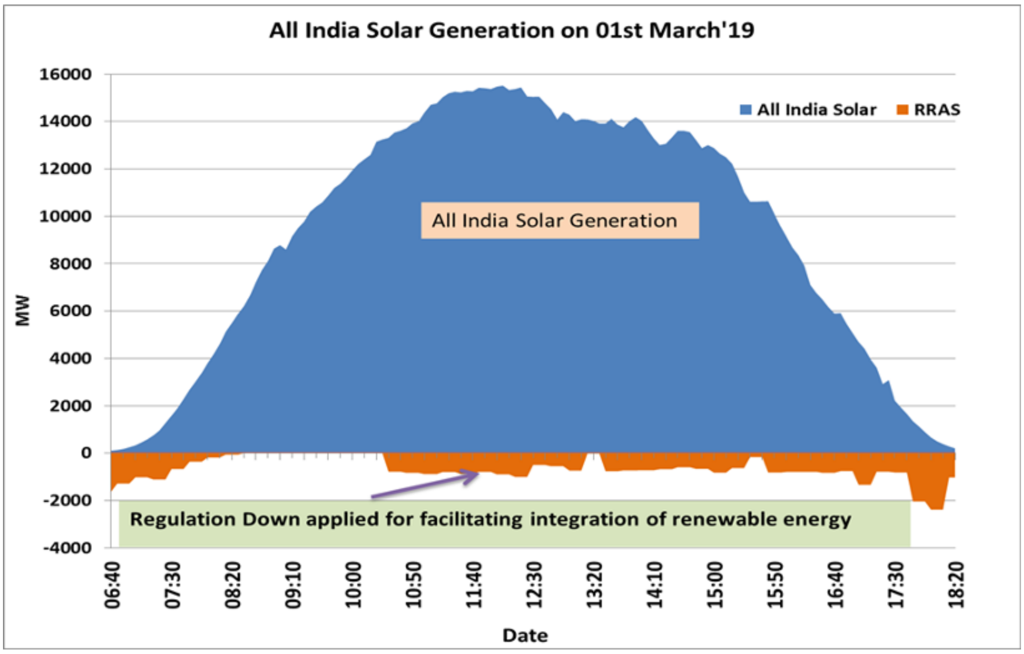


Figure 9: RRAs dispatch to facilitate high solar generation

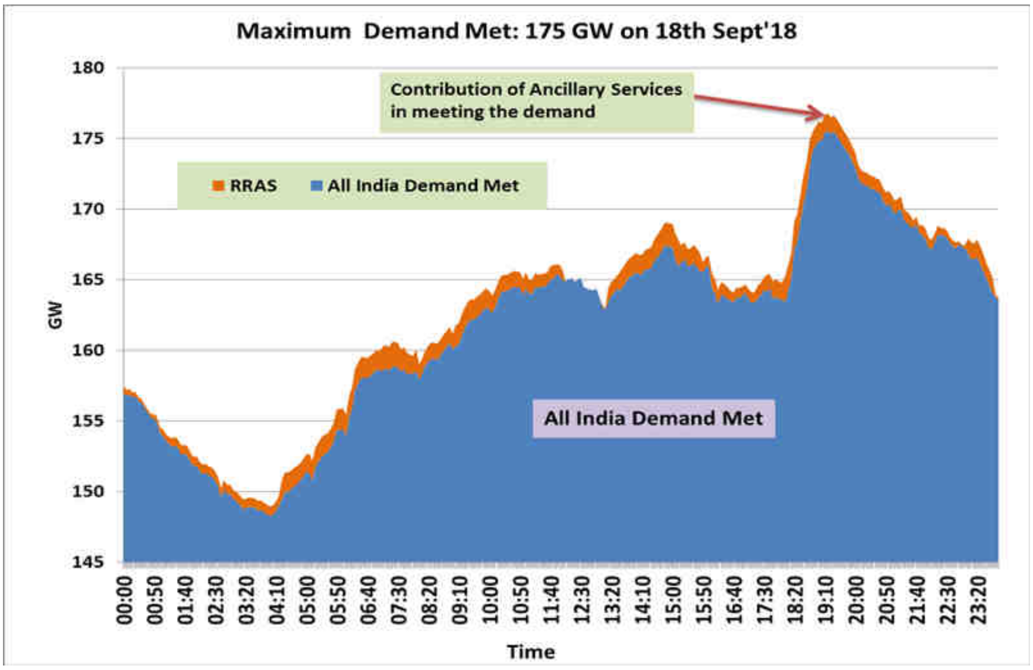


Figure 10: RRAS dispatch during high demand

With the help of in-house development of customized software solution, RRAS helped in improving the frequency profile, congestion management, optimization of reserves dispatch at pan-India level for frequency control, and facilitating integration of renewables. Various challenges have been experienced in the RRAS implementation such as 'gate closure' in the multi-lateral scheduling system, maintaining adequate reserves quantum and forecasting by the utilities for resource adequacy.

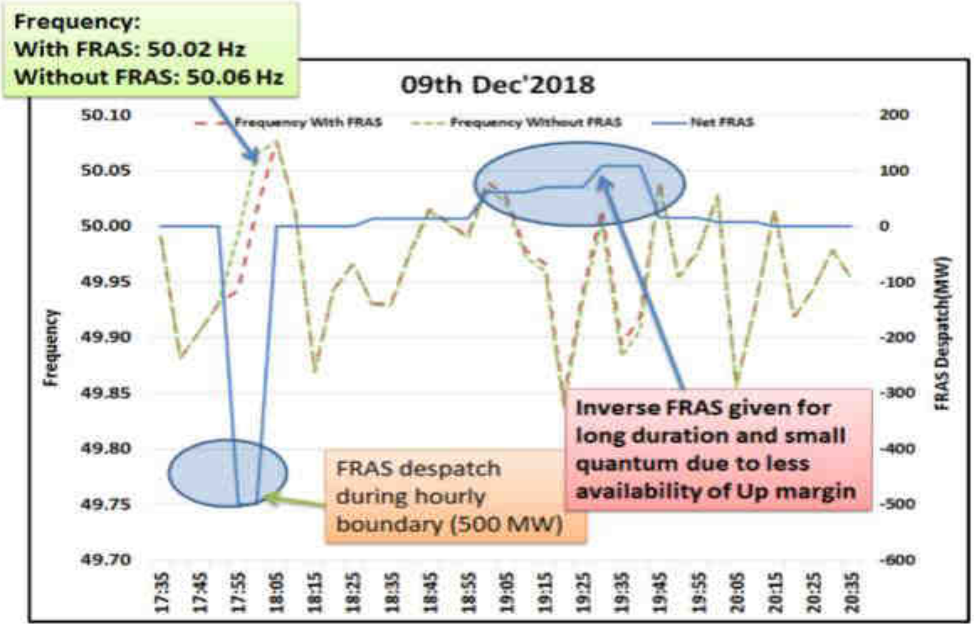


Figure 11: Typical RRAS despatch

FRAS was implemented as 'fast' tertiary control to handle frequency spikes at hourly boundary. The required application software was developed in-house at NLDC/RLDCs. 20 hydro stations in Northern, Eastern and North-Eastern regions with aggregate capacity of 8604 MW participated. Approx. 3 to 4 instructions were issued on daily basis. Instructions for total 9.7 MU FRAS up and 41.6 MU FRAS down were issued during the pilot period. The challenges encountered in the FRAS implementation included determination of minimum threshold quantum to be despatched under FRAS, forecasting & availability declaration by hydro station, lead time for communication of instructions, regulation of power supply by FRAS providers, dilemma of reserves in hydro plants, handling residual energy, primary response, automation, information technology infrastructure and manpower requirements. During the FRAS pilot, difficulties were faced in the squaring off of the despatched FRAS energy due to various reasons.

3.7. Salient features of secondary frequency control

Five stations were identified for providing secondary response under the pilot project on Automatic Generation Control (AGC), viz. Dadri-II (NR), Mouda-II (WR), Simhadri (SR), Barh (ER), Bongaigaon (NER). The first pilot project on AGC at NTPC Dadri Stage-II was implemented in January 2018. Thereafter, AGC pilot projects have also been operationalized at NTPC Simhadri Stage-II (on 16th November 2018), NTPC Mauda Stage-II (on 30th January 2019), NTPC Barh (on 23rd August, 2019) and NTPC Bongaigaon (Nov 2019). Highlights are as under:

- AGC pilot project is being operated from NLDC.
- Required hardware and software has been installed at NLDC and the stations under AGC
- The AGC software has been integrated with the existing SCADA system at NLDC
- The five regional grids are considered as a balancing area. The ACE of the regional grid is computed and scaled down to derive the plant AGC set point
- AGC set point is communicated every 2 second to the power station through Inter Control Center Communications Protocol (ICCP)
- The unit Digital Control System (DCS) accepts AGC signal sent by NLDC when the unit is set into "Remote" by the unit operator. When the unit is placed in "Local" mode, the unit DCS only receives the signal but does not act on the signal
- Delta P is the AGC correction is calculated as the difference between plant AGC set point and the reference Unit Load Set Point. The plant operator has the choice to distribute the plant AGC set point in between the two units by a factor.
- Aggregated AGC incremental MW signals over 15 minutes/5 minutes are logged at NLDC and the power station as AGC MWh.
- Deviation in MWh for every 15-minute time block are worked out as: - MWh deviation = (Actual MWh)- (Scheduled MWh)- (AGC MWh); This is settled as per the existing DSM Regulations
- For AGC MWh computed for each 5-minute time block, 50 paise/kWh mark-up is payable to the participating station from the regional DSM pool for both positive AGC MWh generation and negative AGC MWh reduction. Data is submitted by NLDC to respective RPCs in the agreed format on a weekly basis.

Implementation of AGC on hydro and solar power plants is also being undertaken with USAID under Greening the Grid (GtG) RISE project. Karnataka Power Transmission Corporation Ltd. together with USAID has proposed AGC pilot project on Varahi and Sharavathi Hydro Power Plants. Similar pilot projects could be taken up in the RE rich and few of the larger States. CERC vide its order dated 28th August 2019 in Petition No.: 319/RC/2018 directed roll out of AGC pan India. Under phase-I, implementation would be taken up in all regional entity generators whose tariff is approved/adopted by CERC. Implementation in the regional entity generators having merchant capacity shall be taken up in the second phase. The basic infrastructure required for implementation of AGC are as under:

- Reliable wideband communication between SLDC and generating station
- AGC application software in SCADA/EMS at SLDC
- AGC application software at Generating station
- Measurement and computation of Area control error at every 4 seconds

4. Dimensioning of reserves for intrastate Ancillary Services

"Errors, like straws, upon the surface flow, He who would search for pearls must dive below"

4.1. System imbalance due to stochastic factors

Imbalance in the power system could be attributed to the following factors:

i. Forced/unplanned outage (Generation loss or load loss)
ii. Load forecast error
iii. Forecast error of RES (Wind & Solar) generation
iv. Difference between scheduled and actual generation

Deviation of the frequency from the nominal value is a consequence of the above imbalances.

4.2. System imbalance due to deterministic factors

The changes in the physical supply or the demand are generally gradual (except under contingency). However, in the electricity market, the interchange schedules are specified as discreet step functions in hourly or sub-hourly intervals (15-min in India).

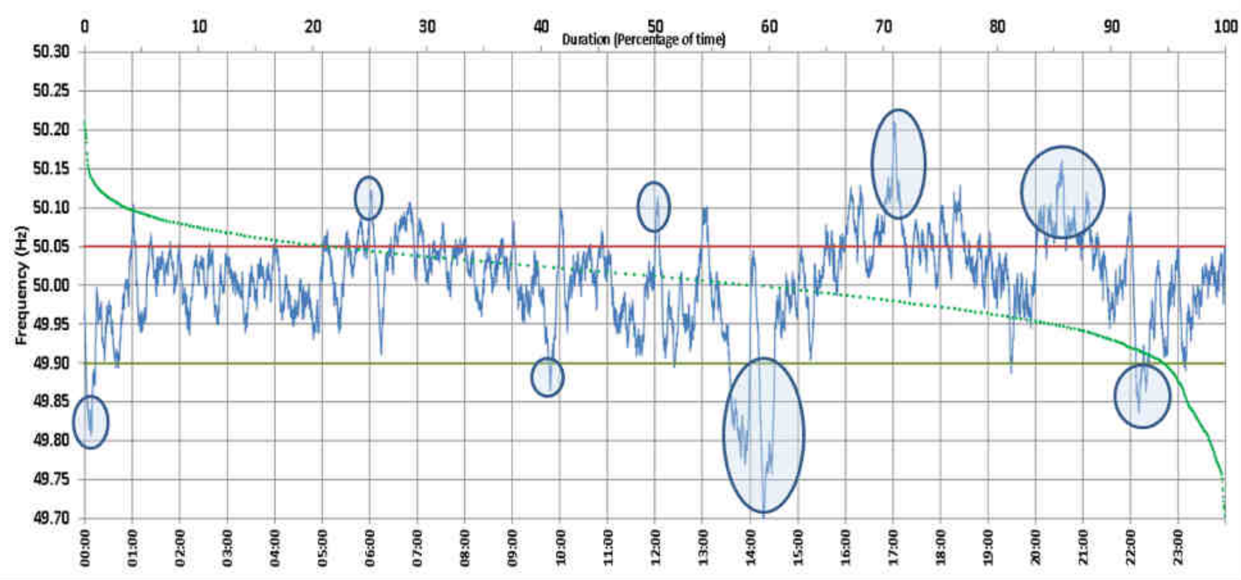


Figure 12:Sharp variations in frequency at 15-min and hourly boundaries on a typical day

This implies that in a given time block, the interchange schedule would never match the demand or supply perfectly – it would either be 'over-scheduled' or 'under scheduled'. Thus, the deviation of actual interchange from the interchange schedule are inevitable in a power system. These deviations are sometimes referred as 'schedule leaps'. Schedule leaps are quite significant at the boundary of the defined time blocks due to step changes in the schedule. The schedule leaps are also reflected in the frequency profile of the grid. [Source:https://www.neon-energie.de/Hirth-Ziegenhagen-2015-Balancing-Power-Variable-Renewables-Links.pdf].

The scheduling and the settlement interval or period are a part of the electricity market design. It influences the way in which the contracts are designed in the electricity market. Therefore, increasing the granularity of scheduling interval could help in regulating the schedule leaps. In fact, the quantum of reserves required for regulation and ramp management would significantly reduce with the reduction in the scheduling interval enhancing market liquidity and enabling access to fast markets. The same is illustrated through the figures extracted from the NREL report on 'operating reserves and variable generation'. [https://www.nrel.gov/docs/fy11osti/51978.pdf.](https://www.nrel.gov/docs/fy11osti/51978.pdf) NITI Aayog in its Report on India's Renewable Electricity Roadmap 2030 [section 3.23 (ii)] also highlighted that the ancillary service requirement would be lower in case of 5-min scheduling.

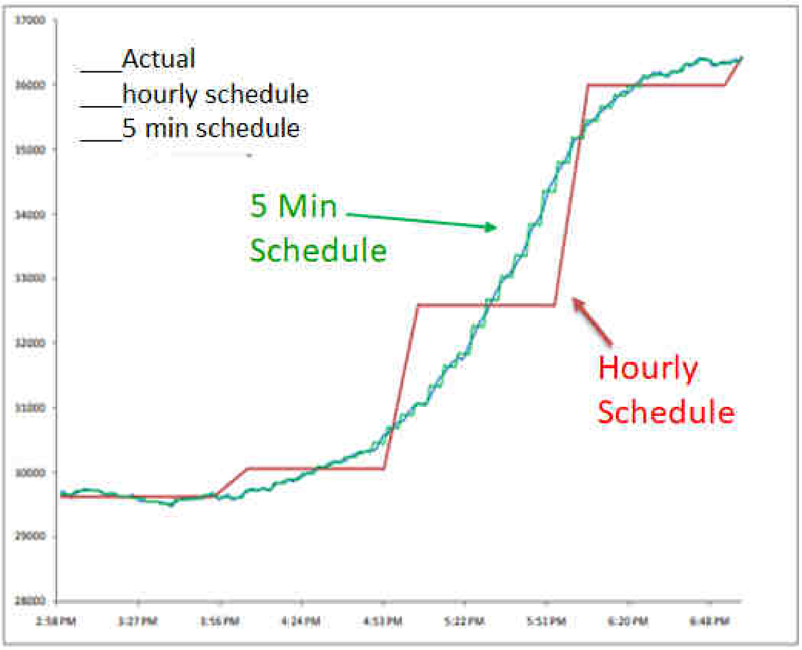


Figure 13: Hourly scheduling vis-a-vis 5-minute scheduling

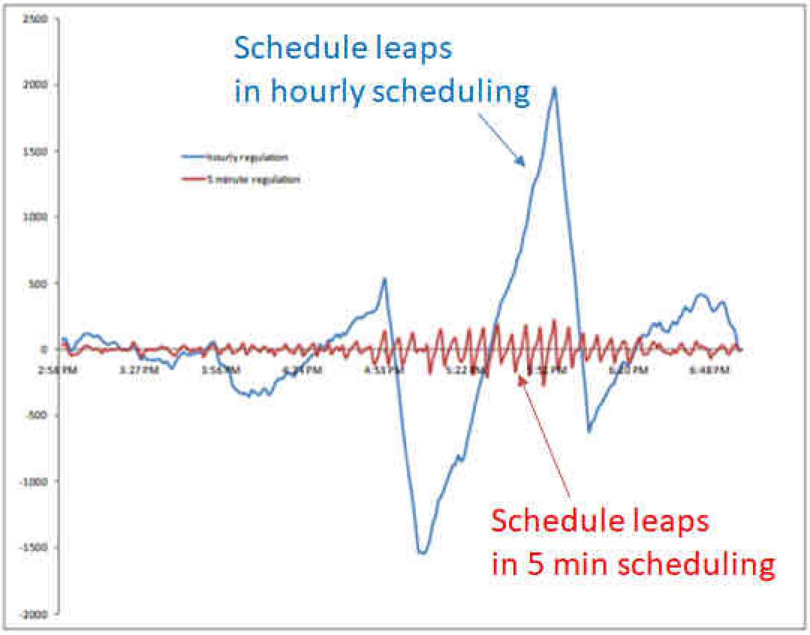


Figure 14: Regulation requirement for hourly scheduling vis-a-vis 5-min scheduling

4.3. Primary reserves as per CERC roadmap

CERC vide its order dated 13th October, 2015 in Petition no 11/SM/2015 envisaged loss of complete power station as a credible contingency for maintaining primary reserve. It states that a minimum primary reserve of 4000 MW shall be maintained to arrest the sudden frequency drop post outage of an Ultra Mega Power Plant or any similar event. This reserve has to be distributed in all India generators to take advantage of diversity. IEGC 5.2 is applicable to intrastate generators as well as interstate generating stations. Thus, the reserves for primary response have to be maintained in all coal-fired units of capacity 200 MW and above, all gas turbines of capacity 50 MW and above and all hydro units of capacity 25 MW and above. All the units on bar would respond as per their droop characteristics to stabilize the frequency post contingency.

In order to ensure adequate reserves for primary response, the injection schedule of the intrastate generating stations issued by the SLDCs should not exceed the capacity on bar less normative auxiliary consumption of the respective stations. It is desirable to have primary reserves distributed over large number of units instead of maintaining it in few units. This could be an effective strategy for ensuring availability of response and avoiding large variation in the power flow across the network due to the primary response during the quasi-steady state.

The respective SERCs could mandate the frequency response obligations of the intrastate entities. The respective SLDCs could compute the frequency response characteristics for different contingencies and compare it with the obligations. The computation could be as per the 'Procedure for Assessment of Frequency Response Characteristic (FRC) of control areas in Indian power system" that was approved by CERC vide its order in petitions 47/MP/2012, 49/MP/2012, 50/MP/2012, 51/MP/2012 and 52/MP/2012.

4.4. Secondary reserves as per CERC roadmap

Secondary reserves are deployed to restore the primary reserves, and keeping the system ready to handle the next contingency. The primary response is required to stabilize the frequency while the secondary reserve is to be deployed to restore the primary reserve and restore the frequency to 50 Hz. Secondary reserve is deployed in the area where the contingency has occurred. The CERC roadmap on reserves, envisaged that each region should maintain secondary reserve equal to the size of the largest unit in the region. The secondary reserves to be maintained at regional level as per the CERC roadmap are tabulated below. These reserves would be available only if there is un-requisitioned surplus power in the ISGS.

Table 5: Secondary reserves recommended in the CERC roadmap

Region	Reserve at regional level (MW)
North	800
East	660
West	800
South	1000
North East	363
Total	**3623**

4.5. Tertiary reserves as per CERC roadmap

Tertiary reserves are required to replenish the secondary reserves. Hon'ble CERC vide its Suo moto order 11/SM/2015 dated 13.10.2015 in the matter of operationalization of spinning reserves envisaged a that "*tertiary reserves should be maintained in a decentralized fashion by each state control area for at least 50% of the largest generating unit available in the state control area.*" Aggregate tertiary reserves at intrastate level computed from the above deterministic approach is tabulated as under:

Table 6: Tertiary reserve recommended in the CERC roadmap

Region	Aggregate tertiary reserves at the intrastate level (MW)
North	1658
East	857
West	1353
South	1343
North east	65
Total	**5218**

4.6. Probabilistic methods for reserve assessment

The reserves required for a control area varies seasonally, daily and time block wise. Methodologies for estimation of reserves can be either deterministic or probabilistic. Reserves based on largest possible generation incident in a control area is a deterministic approach. It is desirable to adopt a probabilistic approach for reserve assessment to account for deviation patterns, size of control area, severe events and their probability. The idea of probabilistic methods is to size the reserve such that a certain, pre-defined level of system reliability is met. These methods estimate the density function of system imbalances and use a cut-off to determine the size of the reserve. Reserves can be determined for long time periods such as one year or more frequent periods depending on the current or expected status of the system. Reserves based on deterministic sizing is usually static whereas probabilistic sizing can be static or dynamic.

In probabilistic methods, different parameters can be considered for estimation of reserves viz. forced outage rates, capacity outage probabilities, forecast errors, area control errors, deviations due to imbalances and combination of above etc. A probabilistic approach called Graf-Haubrich is used in Germany for dimensioning of secondary and tertiary control reserves. In Graf-Haubrich method different sources of imbalances (load forecast errors, power plant outages etc.) are convoluted to probability density function. The probability density function gives level of significance for required amounts of reserves. The schematic of Graf-Haubrich method adopted in Germany is shown below.

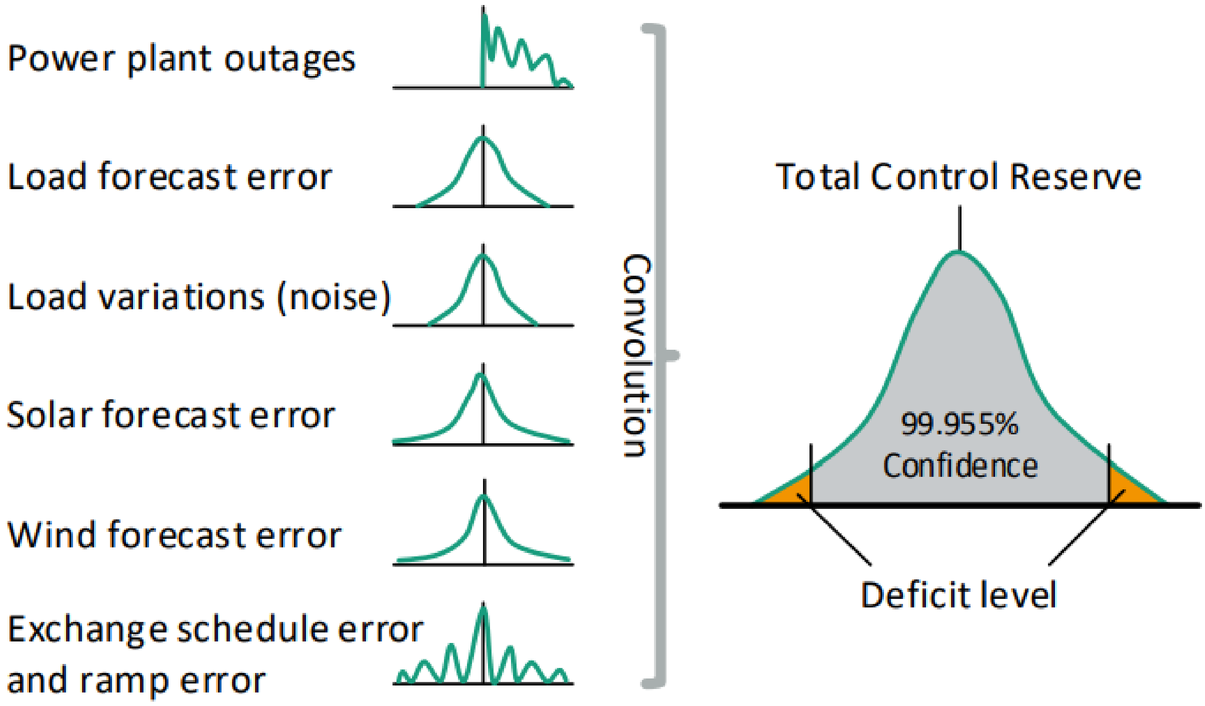


Figure 15: Schematic of Graf-Haubrich method for determination of reserves

4.7. Area Control Error

The imbalance of a control area is generally measured in terms of Area Control Error (ACE). ACE is computed as below.

Area Control Error (ACE) = (Ia - Is) - 10 * Bf * (Fa - 50) + Eσ

Ia = Actual net interchange [-ve for import, +ve for export]

Is= Scheduled net interchange

Bf = Frequency bias coefficient in MW/0.1 Hz, negative value

Fa = Actual system frequency

Eσ= Measurement error

Positive ACE implies over-generation and it causes interconnection frequency to rise while a large negative ACE implies under generation and it causes interconnection frequency to drop. The deviation from schedule on account of power plant outages, load forecast error, load variations, solar forecast error, wind forecast error and scheduling error would be reflected in the Area Control Error. ACE is being computed at all RLDCs by considering 10*Bf as 4% of control area load and neglecting measurement error. Thus, the probability density function of ACE could be utilized for probabilistic assessment of balancing reserves. Schematic is illustrated below:

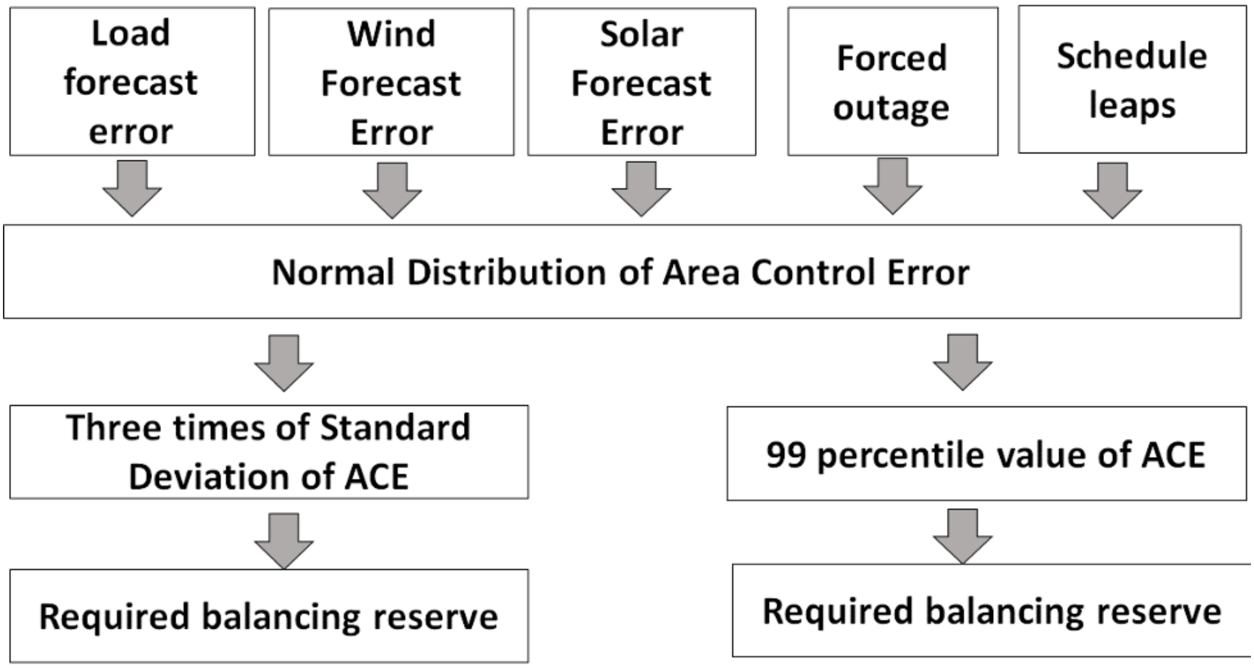


Figure 16: Schematic of probabilistic computation of required reserves

4.8. Reserve assessment from 99 percentile of area control error

Percentiles are used to understand and interpret data. They indicate the values below which a certain percentage of the data in a data set is found. Basically, percentile is a number where a certain percentage of values fall below that number. The nth percentile of a set of data is the value at which n percent of the data is below it. For example, if 99^{th} percentile of data set is 1500 then it means that 99 percentage of values fall below 1500. 99 percentile values of ACE computed state wise are tabulated below. As the mean of ACE was not zero, 99 percentile value of ACE will be different for positive and negative ACE. 99 percentiles of ACE could be considered as secondary reserve requirement. [ENTSOE System Operation guidelines suggests this for Frequency Restoration Reserves]. Typical values of the 99percentile ACE value of states for the period April 2018 to March 2019 are tabulated below.

Table 7: 99th percentile of ACE of Western Region

Region/State	99 percentile Positive ACE (MW)	99 percentile Negative ACE (MW)
Maharashtra	640	538
Gujarat	576	625
Madhya Pradesh	636	582
Chhattisgarh	271	362
Goa	85	92
UT Dadra and Nagar Haveli	67	70
UT Daman and Diu	49	50

Table 8: 99th percentile of ACE of Southern Region

Region/State	99 percentile Positive ACE (MW)	99 percentile Negative ACE (MW)
Andhra Pradesh	672	560
Telangana	620	595
Karnataka	638	768
Kerala	240	208
Tamil Nadu	720	630
UT Pondicherry	60	80

Table 9: 99th percentile of ACE of Northern Region

Region/State	99 percentile Positive ACE (MW)	99 percentile Negative ACE (MW)
Punjab	744	660
Haryana	496	640
Rajasthan	718	788
Uttar Pradesh	693	705
Delhi	247	310
Himachal Pradesh	383	273
UT Jammu & Kashmir	382	607
Uttarakhand	337	458
UT Chandigarh	87	79

Table 10: 99th percentile of ACE of Eastern Region

Region/State	99 percentile Positive ACE (MW)	99 percentile Negative ACE (MW)
Bihar	388	545
Jharkhand	194	347
DVC	395	313
Odisha	302	338
West Bengal	466	535
Sikkim	52	61

Table 11: 99th percentile of ACE of North-eastern Region

Region/State	99 percentile Positive ACE (MW)	99 percentile Negative ACE (MW)
Arunachal Pradesh	48	88
Assam	152	208
Manipur	42	50
Meghalaya	62	57
Mizoram	26	44
Nagaland	41	46
Tripura	85	96

4.9. Reserve assessment from standard deviation of area control error

The distribution curve of ACE of a control area could be used to estimate the reserve required for that control area. Three times of standard deviations of the mean of ACE of individual control areas could be considered as the required power balancing reserve for specified hourly time horizon. Normal distribution of ACE would give percentage of values that lie within a band around the mean with a width of one, two and three standard deviations **(σ)**, respectively; more accurately, 68.27%, 95.45% and 99.73% of the values lie within one, two and three standard deviations of the mean, respectively.

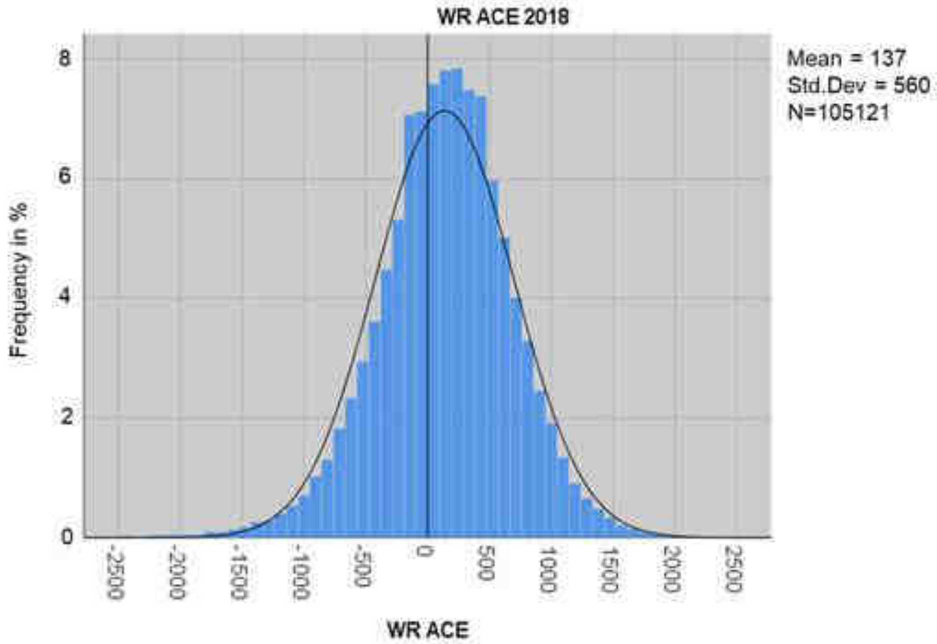


Figure 17: Frequency distribution of ACE of Western Region (Jan-Dec 2018)

As three times of standard deviations of the mean covers 99.73% of values, required sizing of secondary and tertiary reserves for a control area could be considered as three times of standard deviations of the mean of ACE. Based on above approach, three times of standard deviations of the mean of ACE of WR and its constituents were calculated and tabulated below. For computation, ACE values for the year 2018 and 2019 (up to 31st Aug 2019) were considered.

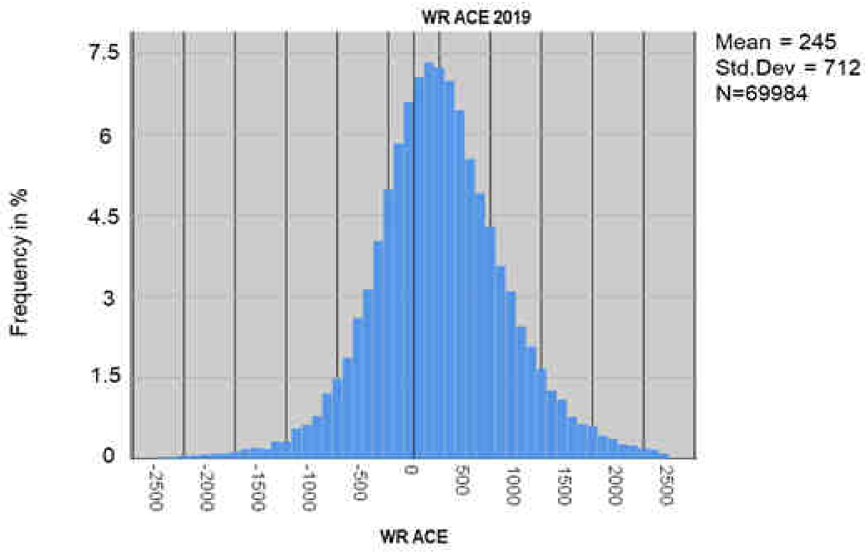


Figure 18: Frequency distribution of ACE of Western Region (Jan-Aug 2019)

Density function plot of ACE for WR and its constituents are enclosed as **Annex-IV**. Summary is as below:

Table 12: Reserve required as per 3sigma method

Region/State	Reserves required (as per CERC roadmap) (MW)	Reserves required (3 times of Standard Deviation)	
		2018 (MW)	2019* (up to 31st Aug) (MW)
Maharashtra	330	759	699
Gujarat	330	660	714
Madhya Pradesh	330	594	675
Chhattisgarh	250	318	372
Goa	-	87	81
UT Daman and Diu	-	75	57
UT Dadra and Nagar Haveli	-	81	72
WR	800	1680	2136

4.10. Monitoring and dispatching active energy reserves

It is recommended that probabilistic approach may be adopted for reserve assessment. The computed reserves may be considered as the total reserves needed for secondary control and tertiary control to be kept inside the control area. Percentage share to secondary control and tertiary control may be varied from time to time or fixed. The amount of reserves can be set on an annual basis and reviewed periodically.

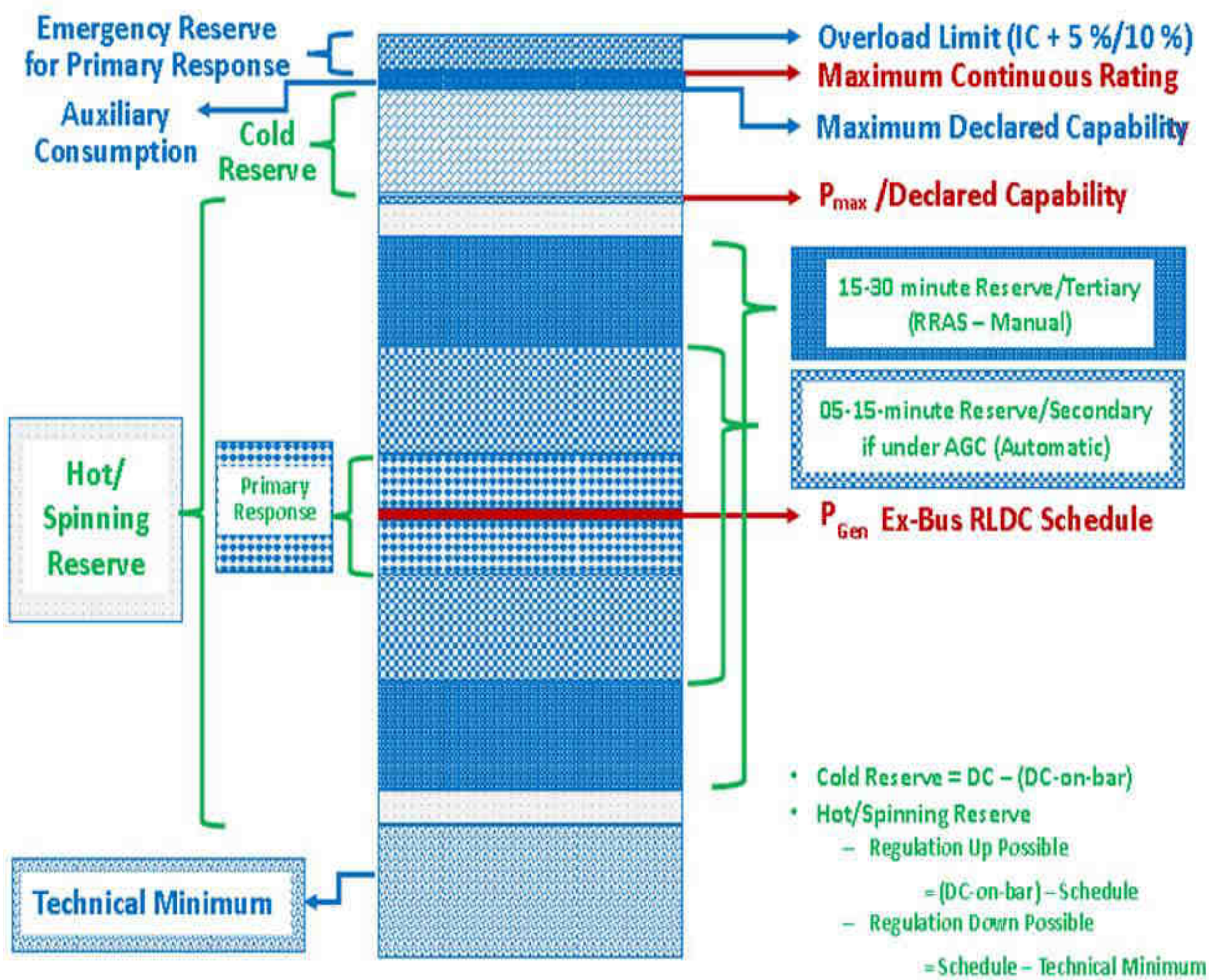


Figure 19: Schematic of reserve margins in a typical unit during a certain time block

The availability of up reserve margin and down reserve margin in all the intrastate generating stations within the State control area and a member in the intrastate DSM pool irrespective of ownership should be computed in real-time and displayed on the operator console in the SLDC control room. This requires notification of norms for Normative Declared Capability, Technical minimum generation capability, ramp up rate, ramp down rate by the SERC. All the intrastate generating stations shall provide the required details to the SLDC. A schematic for reserve margins in a typical unit for a certain time block is illustrated below:

Consequent to the merit order / economic dispatch, the available spinning reserve would get consolidated in the generators having higher variable cost. As a result, the reserves despatch gets constrained by the ramping capability of generation units carrying reserve. The ratio of ramp constrained reserve (that gets despatched) to the total available reserve may vary from 15% to 75%. Reserve available in multiple stations may have to be dispatched simultaneously. In doing so the economy may have to be sacrificed to some extent. The ancillary dispatch instruction could be given to multiple units at a time to exploit the collective ramping capability. It is desirable that suitable incentives may be provided to encourage generators to provide higher ramp rate and number of units providing ramping service is enlarged.

4.11. Economic dispatch vs control area regulation

The dilemma between control area regulation and economic dispatch is well articulated in the classical paper titled 'Considerations in the Regulation of Interconnected Areas', by Nathan Cohn [IEEE Transactions on Power Apparatus and Systems Vol. PAS-86, No. 12 December 1967 pp 1527-1538, https://ieeexplore.ieee.org/document/4073237]. The same is illustrated in figure below.

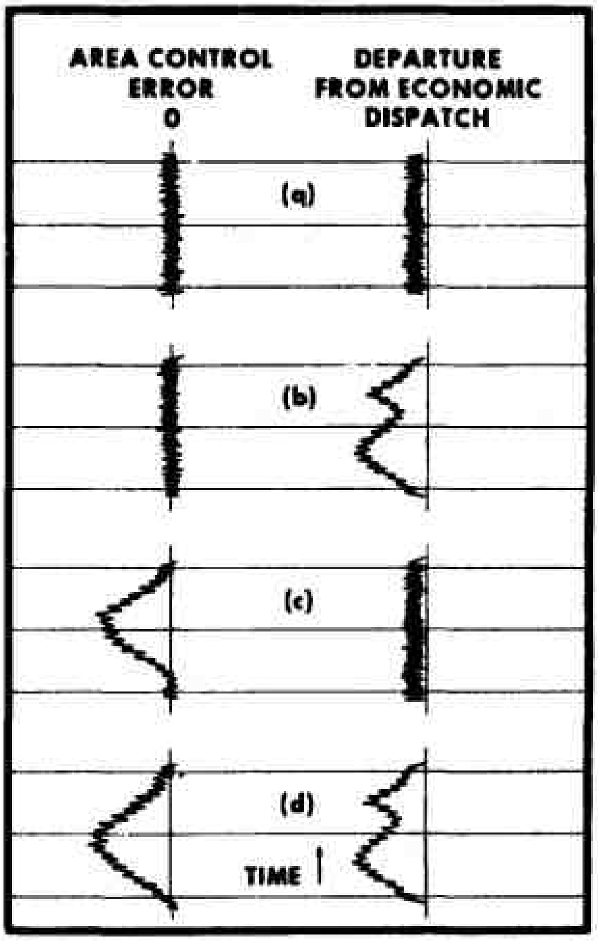


Figure 20: Curves illustrative of control area performance

It states that while pursuing an economic dispatch schedule, the next in line generating source that receives instructions to regulate generation may not have the response characteristics or capabilities or permissible rate of generation change to match the control demand. Also, the control may over-regulate, causing generation changes that exceed the prevailing rate of area load change, with corresponding creation of area control errors.

It may be seen in the figure that good area regulation and optimum economic dispatch are achieved in case (a). In case (b), economic dispatch is sacrificed for good area regulation. In case (c) economic dispatch is achieved at the expense of area regulation. In case (d) neither good area regulation nor economic dispatch are achieved. In view of the above the ramping capability of the units on bar is extremely important. The generating units must be incentivized for declaring a higher ramp rate. The terms and conditions of tariff of central sector generating stations for 2019-24 approved by CERC has mandated a higher return on equity to the generating stations offering a higher ramping capability.

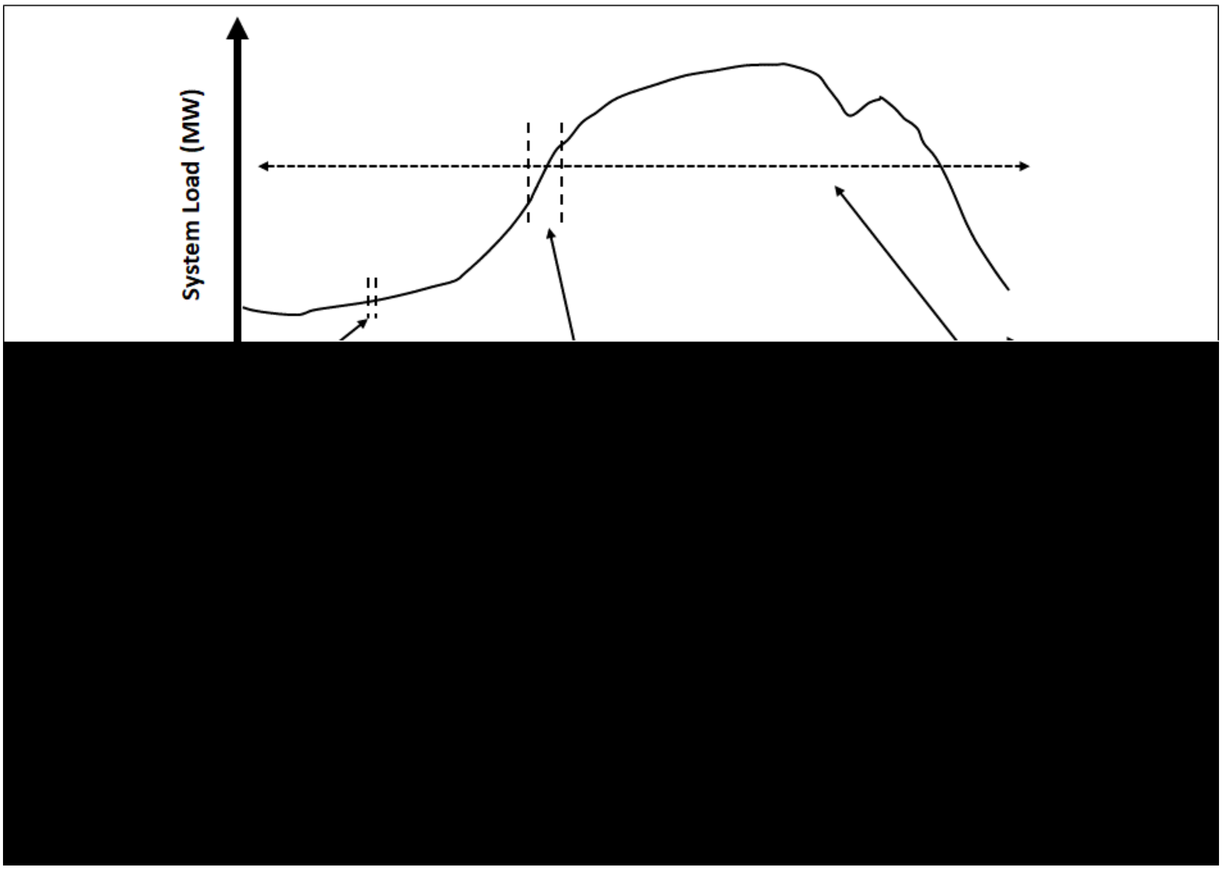


Figure 21: Power system operation time frames

4.12. Unit commitment to ensure reserve adequacy

The depleted reserves would have to be replenished to ensure its adequacy in all time frames. If required, additional units could be brought on bar. Likewise, in case of availability of reserves in excess of the requirement certain units would have to be taken off-bar. This could be accomplished by multi-period optimization of reserves through unit commitment. Thus, unit commitment decision is an integral part of reserve management.

4.13. Voltage Control Ancillary Services in the intrastate system

Adequate availability of static and dynamic sources of reactive power are essential for maintaining voltage profile with the stipulated range. Transmission utilities generally plan shunt compensation in the form of switchable capacitor banks, bus reactors and line reactors. Considering the growing penetration of Variable RE, high capacity evacuation corridors and the large variation in the loading of transmission system the intrastate entities need to be encouraged provide dynamic VAR support for voltage control. At the interstate level the reactive energy exchanges with the grid are charged at 14.5 paise / kVARh if the average voltage during that time block is outside 97% to 103% of nominal. Similar voltage dependent reactive energy pricing could be considered for providing incentives/disincentives reactive energy exchanges with the grid. Considering the capability of VRE to operate in voltage control mode and reactive power control mode and the capability of several hydro units to operate as synchronous condensers. A suitable ancillary service for voltage support could be evolved.

4.14. Black start services in the intrastate system

Black start service is an essential reliability service in power system operation. However very few hydro stations and gas stations have the capability to black start and build the grid post blackout. Regulation 5.8 of the IEGC mandates weekly testing of diesel generators that provide auxiliary supply to black start capable units. Mock trial runs of the system recovery procedure is to be conducted at least once every six months. The model regulation on hydro tariff provides for compensation of the O&M expenses incurred during black start exercise. It also mandates a lumpsum incentive of Rs. 0.5 Lakh for successful demonstration of the black start capability after certification by the SLDC. The above provisions could be suitably considered by the SERCs while drafting the intrastate reserves and ancillary regulations.

5. Survey of preparedness for Intrastate Ancillary Services

"The aim of science is not to open the door to infinite wisdom, but to set a limit to infinite error"

5.1. Survey questionnaire

An online questionnaire was created to assess the availability of the resources and mechanisms for implementation of intrastate ancillary service mechanism. The list of questions is as below:

1. Is intra-State ABT implemented in the State?
2. Does the State have its own grid code?
3. How many government/State owned DISCOMs are there in the State?
4. How many Private DISCOMs are there in the State?
5. How many State-owned generating stations are there in the State and what is their installed capacity in MW?
6. How many private generating (IPP/CPP etc.) stations are there in the State and what is their installed capacity?
7. How many merchant generating stations (without any LTA with the DISCOMs) are there in the State and what is their installed capacity?
8. Does the State follow a common merit order for dispatch instruction for all generators & DISCOMs?
9. In case of private DISCOMs, do they have their own merit order for dispatch?
10. Is there any mechanism to transfer URS power between State owned DISCOMs and private DISCOMs within the state? If yes, how is the settlement done?
11. If need arises, does the SLDC give dispatch instruction to any intra-state generator irrespective of ownership?
12. If need arises, does the SLDC give dispatch instruction to State Owned Generators only?
13. Who prepares merit order?
14. What are the factors considered for preparing the merit-order?
15. Does SLDC have information about fixed cost of all the State generators?
16. Is open access regulation implemented in the State? If yes, up to which voltage level open access is granted?
17. Does SLDC prepare DSM accounts? If Yes, please mention the type of DSM pool?
18. In case of fund generated out of the residual DSM account is maintained, who maintains the fund?
19. What are the criteria to utilize the surplus fund created out of DSM?
20. Who is deciding authority for utilizing the fund created out of DSM?
21. Give details of any other intra-state pool, if any in addition to DSM pool viz State Reactive account pool, Congestion pool etc.

22. What is the norm for technical minimum generation level for state owned thermal generators?
23. Is there any norm specified by SERC for compensation towards part load operation of intra-state thermal stations?
24. Do all the intra-state generators declare DC on day ahead basis?
25. Do all the intra-state generators declare ramp-up and ramp-down rate (in MW/Min)?
26. Do you feel that a more optimized despatch is possible in the state with an algorithm-based approach?
27. Does the State/SLDC do load forecasting?
28. Does the State/SLDC do Renewable (Wind/Solar) generation forecasting?
29. Does the State/SLDC do Renewable (Wind/Solar) generation forecasting?
30. What is the % error (RMSE) in day-ahead demand forecasting?
31. What is the % error (RMSE) in day-ahead Solar forecasting?
32. What is the % error (RMSE) in day-ahead wind forecasting?
33. Have you engaged a forecasting service provider (FSP) for demand/RE forecasting or it is done in-house?
34. Does your forecasting model include weather data in addition to time series data?
35. How does the SLDC do reserve assessment?

5.2. Inferences from the survey responses

Total 22 response were received. Inferences from the survey are as under:

1. Intrastate Grid Code is notified in all the States/Areas.
2. Intrastate ABT in place in 7 States/Areas viz Maharashtra, Madhya Pradesh, Gujarat, Chhattisgarh (in Western Region), Rajasthan, Delhi (in Northern Region) and West Bengal in Eastern Region. In Karnataka, Telangana, Tamil Nadu, Uttarakhand, Himachal Pradesh, Punjab, Bihar and DVC intrastate ABT is either partially implemented or is under progress.
3. 5 States (Tamil Nadu, Uttarakhand, Himachal Pradesh, Punjab and UT of DD) have single government-owned distribution licensee while 13 have multiple distribution licensees. Out of these 13 States, eight states (Odisha, Telangana, Bihar, Karnataka, Madhya Pradesh, Andhra Pradesh, Rajasthan, and Haryana) have only multiple government owned distribution licensees. Kerala has the maximum of 11 distribution licensees- 1 government owned and remaining privately owned.
4. Except Bihar and UT Daman & Diu all 22 States have privately owned generating companies. Nine SLDCs (West Bengal, Maharashtra, Telangana, Gujarat, Karnataka, Chhattisgarh, Andhra Pradesh, Rajasthan and Himachal Pradesh) coordinate the scheduling for merchant IPPs at intrastate level along with generating stations with long-term/medium term PPA.

5. In West Bengal, Gujarat, Kerala, Delhi and DVC the private distribution licensees schedule follows their own merit order while scheduling. Thus, the SLDC presently coordinates the scheduling based on the merit order stack of the contracts entered into only by the government owned distribution licensees within the State.
6. Only Delhi has a mechanism wherein the un-requisitioned surplus power can be scheduled from one intrastate discom to the other intrastate discom by transfer of liability to pay the fixed and variable charge of the corresponding quantum.
7. SLDC Andhra Pradesh, Haryana and DVC give dispatch instructions only to the State-owned generating companies within their jurisdiction. In order to maintain the grid parameters/deviation at State-regional boundary, SLDC Gujarat gives specific dispatch instructions to only those generators having contracts with GUVNL DISCOMs.
8. Seventeen States have stated that only the variable charges are considered for preparing the merit order stack. SLDC Kerala and SLDC Himachal Pradesh consider both Fixed charges and Variable charges for arriving at the merit order stack. SLDC Telangana and Uttarakhand have stated that composite tariff is considered for preparation of the merit order stack if the breakup is not available.
9. West Bengal and PDD of Jammu and Kashmir have stated that Fixed Charges for State owned generating stations are not available.
10. The DSM pool account is revenue neutral in case of Gujarat, Madhya Pradesh, Maharashtra and Rajasthan whereas in case of Chhattisgarh, West Bengal and Delhi the DSM pool account is non-zero sum (surplus). In case of Himachal Pradesh, DSM account has been created by SLDC and the available surplus amount is transferred to the State Power System Development Fund. In case of Delhi the surplus revenue from the DSM account is maintained by the SERC and is utilized for system Strengthening schemes.
11. Existing practices for technical minimum thermal generation are as under:
    a. Madhya Pradesh (55%)
    b. Maharashtra (70 %)
    c. Gujarat (60-70 % considered as declared by stations, SERC yet to notify)
    d. Chhattisgarh (60 – 70 %)
    e. West Bengal (60-70% considered, SERC yet to notify)
    f. Jharkhand (55 %)
    g. Bihar (55%)
    h. Telangana (65-71 %)
    i. Andhra Pradesh (70%)
    j. Karnataka (70 %)
    k. DVC (As declared by the Station)

l. Norms are yet to be notified in West Bengal, Gujarat, Tamil Nadu, Kerala, UT J & K, Rajasthan, Uttarakhand
m. Himachal Pradesh (No thermal generation in the State)
n. Delhi (70%)
o. Haryana (65%)
p. Punjab (As declared by the Stations)

12. All SLDCs have stated that the Declared Capability is available at SLDC. Most of the intrastate generators also submit the ramp rates except in case of Uttarakhand, Chhattisgarh and Jharkhand.
13. Most of the respondents have agreed that a more optimized dispatch is possible through an algorithm-based approach.
14. Maharashtra, Gujarat, Karnataka, Madhya Pradesh have deployed Forecast Service Providers for VRE forecasts.

5.3. Phase wise rolling out intrastate reserves and ancillary services

Based on the survey, and subsequent deliberations the states were placed in the following three groups for rolling out reserves &ancillary services.

Table 13: Roll out of intrastate reserves and ancillary services

Group	States/UTs	Rationale
A	Madhya Pradesh, Maharashtra, Gujarat, Rajasthan, Delhi, West Bengal, Chhattisgarh	Large States SAMAST framework in place
B	Telangana, Karnataka, Andhra Pradesh, Tamil Nadu, Kerala, Uttar Pradesh, Haryana, Punjab, Uttarakhand, Himachal Pradesh, Odisha, Bihar, Jharkhand, DVC	SAMAST framework under implementation
C	NER States, Goa, DD&DNH, Puducherry, Jammu& Kashmir and others	Emerging States and Union territories

6. Simulation model for despatch of reserves

"All models are wrong; the practical question is how wrong do they have to be to not be useful"

6.1. Mandate for scheduling and despatch

The Indian grid is demarcated into several control areas, where the load dispatch centre or system operator of the respective control area controls its generation and/or load to maintain its interchange schedule with other control areas whenever required to do so and contributes to frequency regulation of the synchronously operating system. The regional grids are to be operated with decentralized scheduling and despatch in which the SLDC have the total responsibility for scheduling/dispatching their own generation (including generation of their embedded licensees) and scheduling their drawal from the Interstate generating stations within their share in the respective plant's declared capacity. The SLDCs are responsible for optimum scheduling and despatch of electricity within a State, in accordance with the contracts entered into with the licensees or the generating companies operating in that State. They are also responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the State Grid Code. The Grid code mandates the SLDCs to initiate actions to regulate the drawal of the respective control area from the grid within the net drawal schedule. Thus, the SLDC would have to assess the reserves requirement and ensure its availability and optimal despatch. The role of SLDC would be delineated from distribution licensees while despatching reserves at the state periphery.

6.2. Pilot project using MS Excel Solver

As a pilot project, a simulation model was evolved by using a default optimization tool available in Microsoft Excel Solver for facilitating optimum despatch of reserves. The details of the model are described below.

6.3. Input parameters for the model

i. Installed Capacity
ii. Total Declared capability in MW
iii. Declared capability on-bar (in MW)
iv. Normative Auxiliary Consumption (in %)
v. Schedule in MW
vi. Energy Charge Rate / Variable charge (VC) in Rs/kWh
vii. Ramp-Up rate in (%age of on-bar Capacity) per minute
viii. Ramp-down rate in (%age of on-bar Capacity) per minute
ix. Mandated tertiary reserve to be maintained

6.4. Derived parameters for the model

Based on the above base data, certain derived parameters could be computed and monitored for each time block as under:

i. Regulation Up-reserve = On bar installed capacity – Schedule (fig. in MW)
ii. Regulation Down-reserve = Schedule – Technical Minimum (fig. in MW)
iii. Cold reserve = DC – DC on bar …. (in MW)
iv. Hot spinning reserve = DC on bar – Schedule …. (in MW)
v. Despatchable reserve = Minimum of hot spinning reserve and ramping reserve

6.5. Constraints

i. Pmax less than or equal to (On bar installed capacity – Normative auxiliary consumption (in MW))
ii. Pmin less than or equal to Technical Minimum generation (in MW)
iii. Aggregate schedule of all stations equal to total estimated net load
iv. Import capability limits, scheduling limits, Transmission constraints

6.6. Objective function

The objective function could be to "minimize production cost subject to all constraints". Energy and reserve despatch could be co-optimized. Typical algorithm is attached as **Annex-V**

6.7. Inferences from the pilot projects taken up in three States

Pilot project was taken up by Madhya Pradesh, Maharashtra and Gujarat. It was inferred that co-optimization of energy and reserves dispatch results in reduction in total production cost and the average per unit generation cost. The exercise also revealed that the dispatchable reserves get limited by ramping constraints. The detail report on the pilot projects are enclosed as Annex-**VI**, **VII** and **VIII**.

7. IT infrastructure required for Intra-state ancillary

"Economists could Engineer, Engineers would Economize"

A robust IT infrastructure would be required for implementation. The typical schematic for IT infrastructure and the information flow is illustrated below.

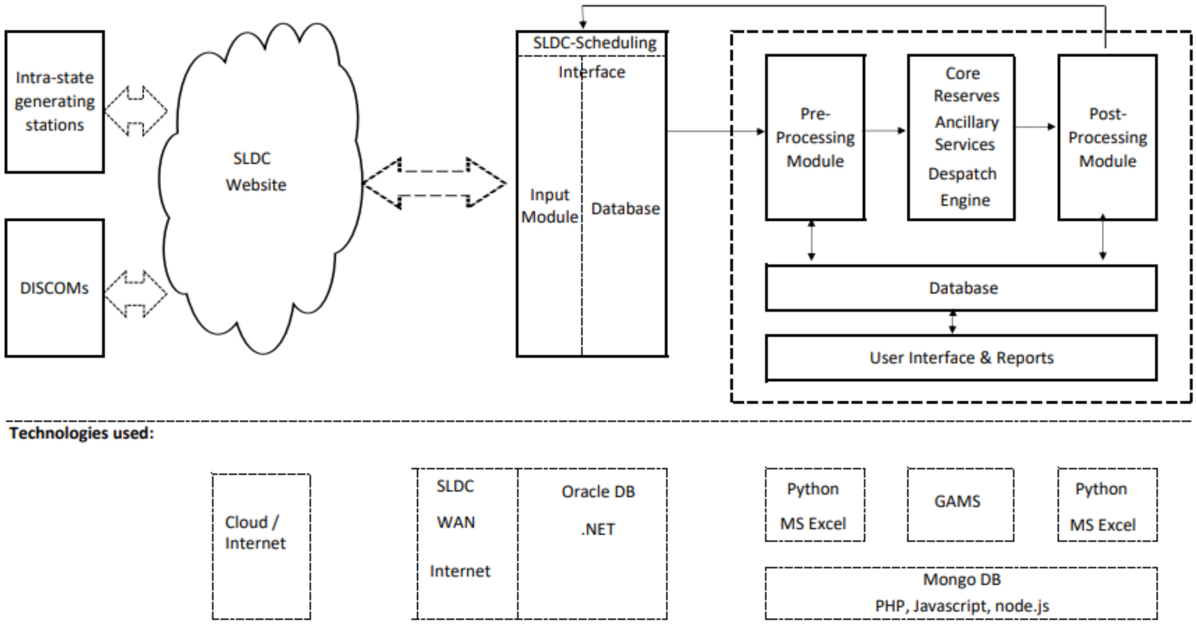


Figure 22: Typical schematic for IT infrastructure and information flow

Writing software requirement specifications (SRS) may be challenging. The application software would evolve organically through a combination of inhouse applications and over-the-shelf external applications deployed with support from a professional system integrator.

A mix of technologies have to be integrated and data exchange has to take place between different layers of technologies at SLDCs and different stakeholders. The infrastructure requirements have to comply with stringent timelines. The scheduling application of respective SLDCs is accessed through public internet by different entities and hence, cyber security and data integrity assumes significant importance. A secure data communication network (Private/Public links) is needed for data exchange between databases in different SLDCs and various stakeholders.

There is a need for application server such as Windows Server with adequate RAM, Disk space, drives and cores. There is also a need for a Database Server (e.g. Oracle DB, .NET, Mongo DB etc.) for data warehousing. The database backup in terms of both physical backup and logical backup assumes significant importance (e.g. SAN - Storage Area Network). There is a need for other technologies including open source ones such as PHP, HTML, CSS, JavaScript, Node.js, Python etc. to interact with the databases, interface with the data and generate user defined reports. The software development is needed SLDCs for seamless data flow for implementation of intra-state ancillary services.

Databases like Oracle DB and Mongo DB could be used in the application development. Oracle DB stores all the sensitive data and for user Interface interaction and graph rendering. Mongo DB is used to keep a replica of data for faster access. This also helps in the keeping the data in Oracle DB safe as the number of data requests from Oracle DB is reduced. The user interface and data analysis web application use Node JS and Python. Node JS is used for web application backend development. Python is used for development of Core-Engine and scripts for fetching data at regular intervals.

The important considerations for the IT infrastructure shall be as under

a. The functional specifications shall be in line with the regulations
b. Test development system
c. Troubleshooting
d. Database applications
e. Data repository
f. Dedicated broadband communication with route diversity
g. Data exchange through API / file transfer
h. Professional optimization engine
i. Cyber security
j. Visualization tools
k. Stakeholder interface
l. Reporting tools
m. Accounting
n. Reconciliation

7.1. Template for Displays /Dashboards

A typical display of available margins in the participating generators in the 96-time blocks is illustrated below. The display should fetch data from the scheduling application and get refreshed after every revision. Similar display could be created for intrastate generating stations.

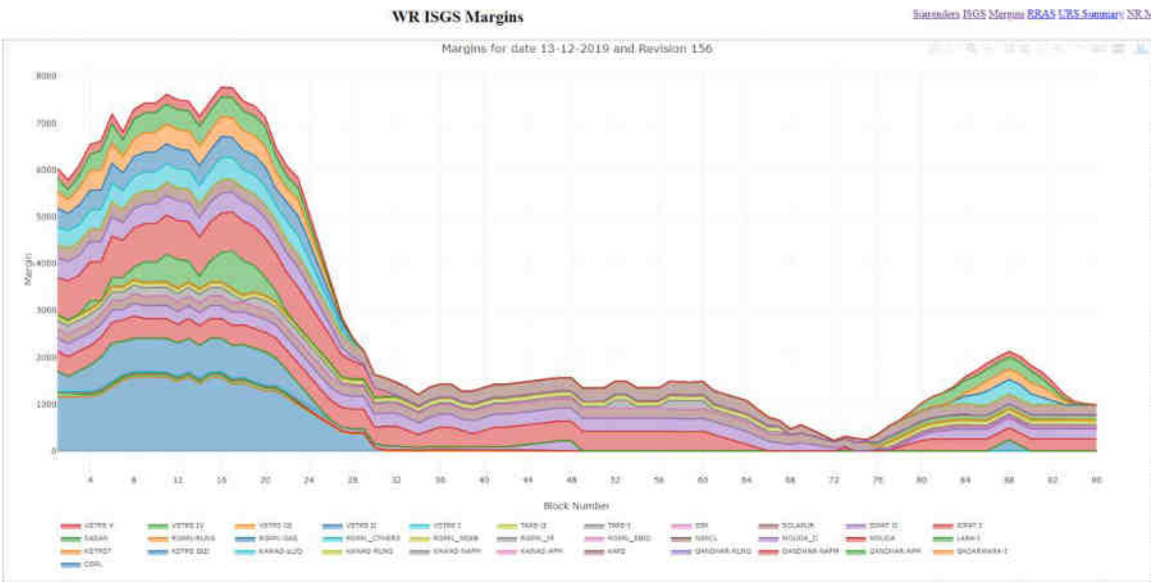


Figure 23: Reserves in western region on a typical day

A typical user interface for dispatching the available reserves is illustrated below.

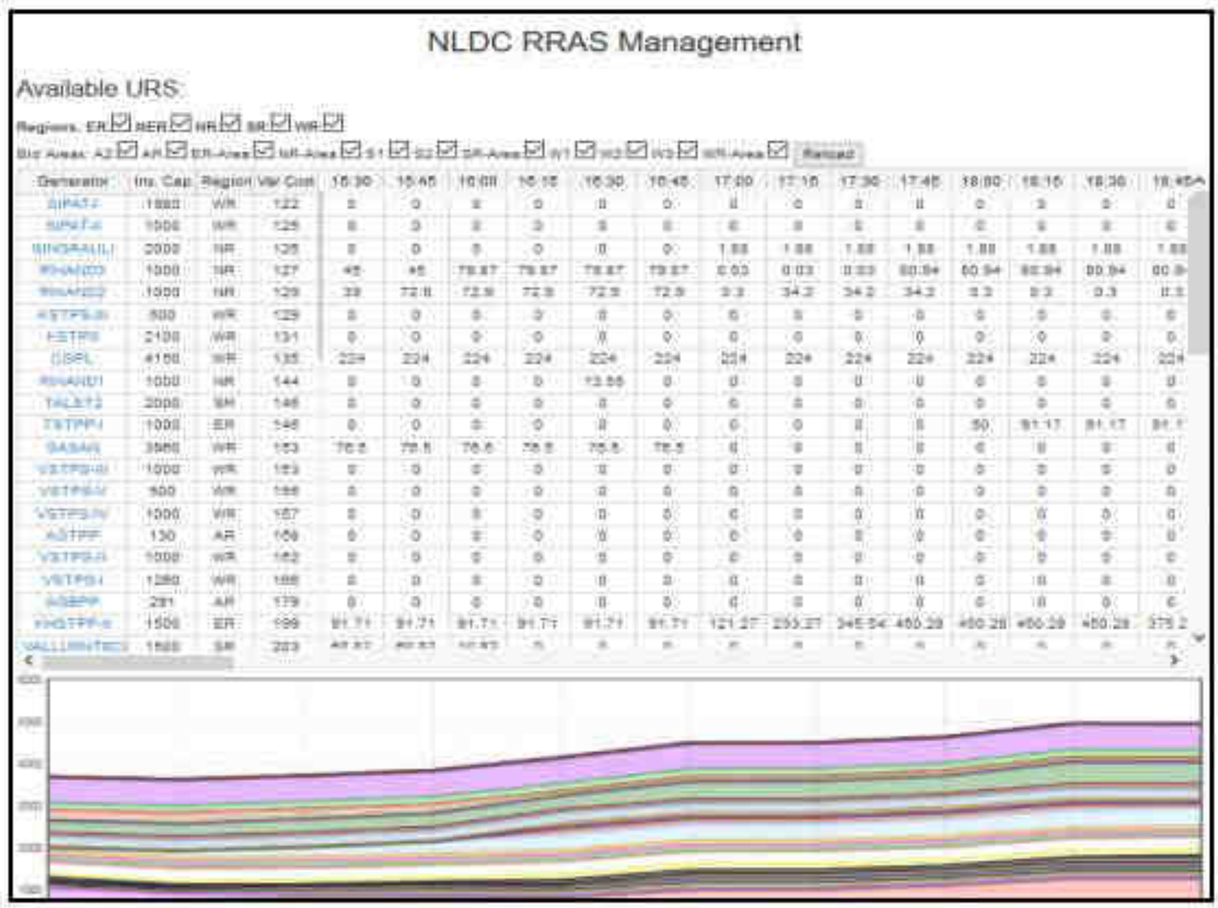


Figure 24: User interface for RRAS management

Source: http://www.iitk.ac.in/npsc/Papers/NPSC2016/1570291562.pdf

7.2. Cost Estimate for IT infrastructure

<table>
<tr><td colspan="3">At SLDC Control Centre</td></tr>
<tr><td>S.No.</td><td>Title</td><td>Approximate Cost (in ₹)</td></tr>
<tr><td>1.</td><td>Annual License for Open source, object-oriented web application development platform</td><td>65,000</td></tr>
<tr><td>2.</td><td>Single User Licenses License for High-level Modeling System for Mathematical Optimization with Solver (E.g. GAMS Optimization Software with CPLEX Solver)
Multi-User/Department (MUD) Licenses:
<table>
<tr><td>License</td><td>Users</td><td>Price</td></tr>
<tr><td>small MUD</td><td>up to 5</td><td>twice the price of a single user system</td></tr>
<tr><td>medium MUD</td><td>up to 10</td><td>three times the price of a single user system</td></tr>
<tr><td>large MUD</td><td>up to 20</td><td>four times the price of a single user system</td></tr>
</table></td><td>7,00,000

(USD 9600 as per 04th February, 2019 Standard Price List)</td></tr>
<tr><td>3.</td><td>Database (Oracle DB – Two Processors) –
Perpetual License
Annual Subscription Charge</td><td>Perpetual License – 18,00,000
Software Update – 2,50,000
Support – 1,00,000</td></tr>
<tr><td>4.</td><td>Two Server(s) (Main and Hot Standby) to install all the desired software</td><td>24,00,000</td></tr>
<tr><td>5.</td><td>Two Workstations</td><td>1,70,000</td></tr>
<tr><td>6.</td><td>Rack</td><td>65,000</td></tr>
<tr><td></td><td>Total</td><td>55,50,000</td></tr>
</table>

https://www.gams.com/fileadmin/standard_price_list.pdf

Disclaimer: The prices are subject to competitive tendering process and customized requirement of the respective SLDCs and will be based on budgetary offer after finalization of requirement. These prices are in no manner reference to the actual costs/prices prevalent in the open market and therefore, are only indicative in nature. The costs of software development and communication for the implementation of the above framework are not included.

8. Recommendations

"It is error only, and not the truth, that shrinks from inquiry"

8.1. Balancing paradigms

The paradigms for balancing in the Indian power system have evolved over the years. Policy and regulatory interventions have been towards facilitating interconnection of the State grid, formation of regional grids and the national synchronous grid to harness diversity benefits and enlarging the balancing area. Initiatives have been also taken to facilitate better portfolio management by enabling access to the market through non-discriminatory open access alongside narrowing of the operating band for frequency and passive balancing through the imbalance price signals (UI/DSM vector, gradual coupling with market). With growing adequacy of generation in the States, the Indian power system is under transition from the 'load-follow-generation' mode (due to chronic scarcity) of operation to the 'generation-follow-load' mode of operation.

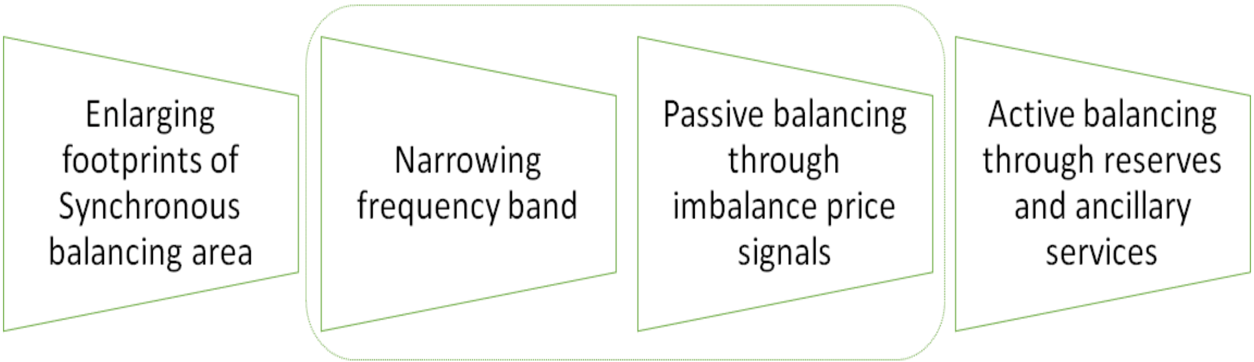


Figure 25: Balancing paradigms

In view of the rise in VRE, it is imperative to take up active balancing through automatic loop controls along with established system of passive balancing. This requires recognition of flexibility attributes (peaking, ramping, load-following, regulation, minimum turn down, overload etc.), assessment of reserve requirement (through deterministic, stochastic techniques), acquiring the reserve capacity (through regulated or competitive route), dispatching reserves optimally through ancillary services and financial settlement of the services rendered.

8.2. Margins in part loaded generators to be considered as reserves

The margins available on part loaded generating units is the spinning reserve to be actuated through different means (primary, secondary or tertiary). Spinning reserves would be created through periodic unit commitment. This would mean that no generating unit would be earmarked exclusively as spinning reserves. Fast starting gas and hydro units could be factored subject to the energy constraints (arising from fuel / water release schedules / reservoir management).

8.3. Distributed primary reserves

It is desirable to have primary reserves distributed over large number of units instead of maintaining it in few units. It would mitigate the risk and ensure availability of primary response. This would avoid large variation in the power flow across the network due to the primary response during the quasi-steady state. The primary reserve for automatic primary response to be maintained in all coal-fired units of capacity 200 MW and above, all gas turbines of capacity 50 MW and above and all hydro units of capacity 25 MW and above. All the units on bar would respond as per their droop characteristics to stabilize the frequency post contingency. In order to ensure adequate reserves for primary response, the injection schedule of the intrastate generating stations issued by the SLDCs should not exceed capacity on bar less normative auxiliary consumption of the respective stations. The primary response could be monitored as per the CERC approved procedure.

8.4. Prerequisites for implementation of essential reliability services

The pre-requisites for implementation of intrastate essential reliability services are as follows:

i. Notification of norms for minimum turn down level, upper scheduling limit and ramp rate
ii. Apriori knowledge of variable charges of intrastate generators
iii. Robust SAMAST system and Intrastate deviation settlement system
iv. Adequacy of human resources and IT infrastructure at SLDC in line with CABIL report
v. Creation of a non-zero and surplus regulatory pool (by design) for deviation settlement pool [through hysteresis and non-linearity in duel, non-reciprocal settlement rate nuances] to take care of default in payments, cashflow

8.5. Computation of area control error

The imbalance of the State control area shall be measured in terms of Area Control Error (ACE) at the state periphery (jurisdiction boundary). ACE shall be computed as below:

Area Control Error (ACE) = (Ia - Is) - 10 * Bf * (Fa - 50) + Eσ

Ia = Actual net interchange [-ve for import, +ve for export]

Is= Scheduled net interchange

Bf = Frequency bias coefficient in MW/0.1 Hz, negative value

Fa = Actual System Frequency

Eσ= Measurement Error

8.6. Dimensioning of secondary and tertiary reserves

The requirement of reserves depends on the forecast errors (demand, RE generation), credible contingencies, scheduling interval and ramping constraints. The reserve requirement shall be assessed periodically with the help of suitable probabilistic method based on historical Area Control Errors. Efforts shall be made to maintain the reserves through unit commitment over a rolling window. The reserve requirement would gradually reduce by the following ways:

- improvement of load forecast
- improvement in wind and solar forecasts
- reduction in frequency of plant outages
- improved intra-day market liquidity allowing better portfolio management
- reduction in scheduling interval
- enhancing market liquidity and access to fast markets
- shorter gate closure

8.7. Pre-requisites for computation of available reserves in real-time

Knowledge of the following scheduling limits is essential for computation of available reserves

i. Normative Auxiliary consumption to obtain the Normative Declared Capacity
ii. Declared ex-bus capacity (Pmax)
iii. Minimum turn down levels (Technical minimum or Pmin) (as % of normative DC)
iv. Ramp-up rate and ramp down rate (% of installed capacity per min)
v. Start-up time
vi. Minimum up time
vii. Minimum shutdown time

The above limits shall be as per the notified norms of operation by the State Electricity Regulatory Commission.

8.8. Implementation of secondary control

Automatic generation control should be implemented particularly in large and renewable-rich states for controlling the area control error. It would require AGC application software at SLDC as well as at the participating generating station; reliable wideband wide band communication system between SLDC and the generating station, measurement and computation of area control error. AGC at the regional level would regulate the output of the participating interstate generating stations while the AGC at the State level would regulate participating intrastate generating stations. Accounting and settlement of residual energy on account of AGC regulation as well as incentive for mileage needs to be evolved.

8.9. Gate closure for dispatching intrastate reserves

In the decentralized scheduling mechanism, the generating stations have the freedom to revise the station declared capacity while the discoms have the freedom to revise their requisitions (in approved long-term and short-term transactions). However, some definite time (ahead of the delivery time) needs to be set aside for enabling the SLDC to assess the available reserve with certainty and to dispatch them in the most optimum manner. This would be possible only with notification of the gate closure time for revision in DC and requisitions and strict adherence to the same by all stakeholders. The gate closure timeline at intrastate level would have to be aligned with the gate closure at the interstate level.

8.10. Sanctity of variable charges or energy charge rate

The merit order stack for dispatching the reserves is prepared from the ex-ante declared energy charge rate. Wherever there is single part generation tariff, the concept of incremental cost may have to be considered. This would get factored in the bids when reserves are arranged competitively. For the purpose of ancillary, post facto revisions should be avoided in the energy charge rate declared ex-ante by the generating station.

8.11. Sanctity of ex-ante DC and injection schedule

Available up-reserves is derived from the DC and the injection schedule. Therefore, no post facto revisions should be allowed in the DC and the injection schedules.

8.12. Computation of available reserves in real time

The reserves available in real-time shall be computed as under:

a. Cold reserve = Total DC minus DC on bar
b. Hot spinning up Reserve = DC_on bar minus Injection Schedule
c. Hot spinning down Reserve = Injection Schedule minus Technical minimum

Schedules ramp rate = (Schedule in block T+1) minus (Schedule in block T)

The dispatchable reserves shall be limited by the maximum station ramp rate.

The tertiary reserves of a State in the interstate generating stations shall be computed separately with reference to the entitlement of that State in the concerned ISGS.

8.13. Monitoring of available reserves

Monitoring availability of reserves in real time assumes importance for its effective deployment in the most optimal way. The mechanisms and tools for facilitation of reserve monitoring & deployment by real time operators at SLDC must enable the operator

a. to see the trend of reserve available for next few time blocks
b. to decide how much reserve is to be pressed in to service
c. to assess the cost of these reserves
d. to ensure most optimal deployment of reserves

Reserve cannot be measured by meters. It is an assessment only. Besides active/reactive power reserves must have following attributes – Energy delivered, time of delivery, cost of carrying reserves, and cost of dispatching. The reserves available in hydro units is energy constrained due to inflows/reservoir levels and water release schedule for storage hydro while the reserves available in thermal units is ramp constrained.

8.14. Unit commitment to ensure reserves

Unit commitment is essential as it would ensure reserves over a rolling window. Under provisioned unit commitment would reduce availability of online reserves as well as the overall cost while over provisioned unit commitment enhances the quantum of online reserves and the overall cost. However, unit commitment is a lumpy decision and there is no unique or simple solution. It calls for information on start-up cost, shut-down costs, start-up time, minimum operating time of units etc. Presently the unit commitment decisions are being taken heuristically. A more rigorous and scientific approach for unit commitment is desirable in future. Further Value of Lost Load becomes important in the context of unit commitment.

8.15. Despatch of reserves

Merit order stack (based on the energy charge rate) of the available reserves shall be prepared by the SLDC. The role of SLDC shall be delineated from discoms in optimizing the dispatch of reserves. The decision regarding the quantum of reserves to be despatched shall be taken based on the following operating conditions: Trend of Area Control Error, Ramping capability of the available vis-à-vis observed ramp in the netload, congestion management etc. Adoption of algorithmic approach for co-optimization of energy and reserves is desirable to minimize the total production cost. Mechanisms to override the infeasibilities observed during the optimal dispatch would evolve with experience.

8.16. Honoring intrastate transmission constraints

The evacuation constraints from the intrastate generators and the transfer capability of different corridors within the intrastate network shall be honored while dispatch of reserves.

8.17. Creation of virtual ancillary entity

Reserves shall be despatched from the ancillary service providers to pool (or vice-versa) without disturbing the underlying power purchase agreements and requisitions. A virtual ancillary entity shall be created within the intrastate scheduling application to convert single entry. The VAE shall be a member of the intrastate deviation pool. It shall act as the counterparty for the schedule prepared for despatch of reserves by the ancillary services providers. For regulation up service, power shall be scheduled from the generating station to the virtual ancillary entity by the concerned nodal agency, until such time the nodal agency gives instruction for withdrawal of service. For regulation down service, power shall be scheduled from the virtual ancillary entity to the generating station, so that effective scheduled injection of the generating station comes down, until such time the nodal agency gives instruction for withdrawal of service.

Scheduling of reserves through VAE will enable scheduling of reserves without unsettling existing contracts. It would also establish a double entry system in the dispatch of reserves and enable check and balance in the mechanism.

8.18. Incentives for essential reliability service providers

Suitable mechanisms for compensating and incentivizing various flexibility services (ramping, reserve regulation, peaking etc.) could be evolved in the State through a consultative process.

8.19. Settlement of despatched reserves through regulatory pool account

The despatched reserves shall be treated as deemed delivered. It shall be subsumed in the injection schedule derived by aggregation of the requisition of all beneficiaries of that station.

Thus, the deviation of the station shall be computed by subtracting the measured injection from the scheduled injection (including ancillary). The ancillary service provider shall be remunerated for the energy scheduled at the energy rate approved/adopted by the regulatory commission plus a mark-up to be decided by the SERC. The surplus available in the intrastate imbalance pool could be used for compensating the ancillary service providers. The actual interchange of VAE with the grid would be zero as it is not a physical entity and it is not bounded by meters. The energy despatched under Reserves Regulation Ancillary Services would be deemed as delivered ex-bus. However, VAE would be a member of the intrastate DSM pool. Separate account shall be maintained for collection and disbursement of charges related with reserves dispatch. After gaining sufficient experience the ambit of ancillary service providers could be expanded by evolving suitable mechanism for procuring reserves competitively. The settlement period could initially be 15-min. Settlement at 5-min interval could be considered subsequently when the matching infrastructure for scheduling, energy metering, accounting and settlement is available.

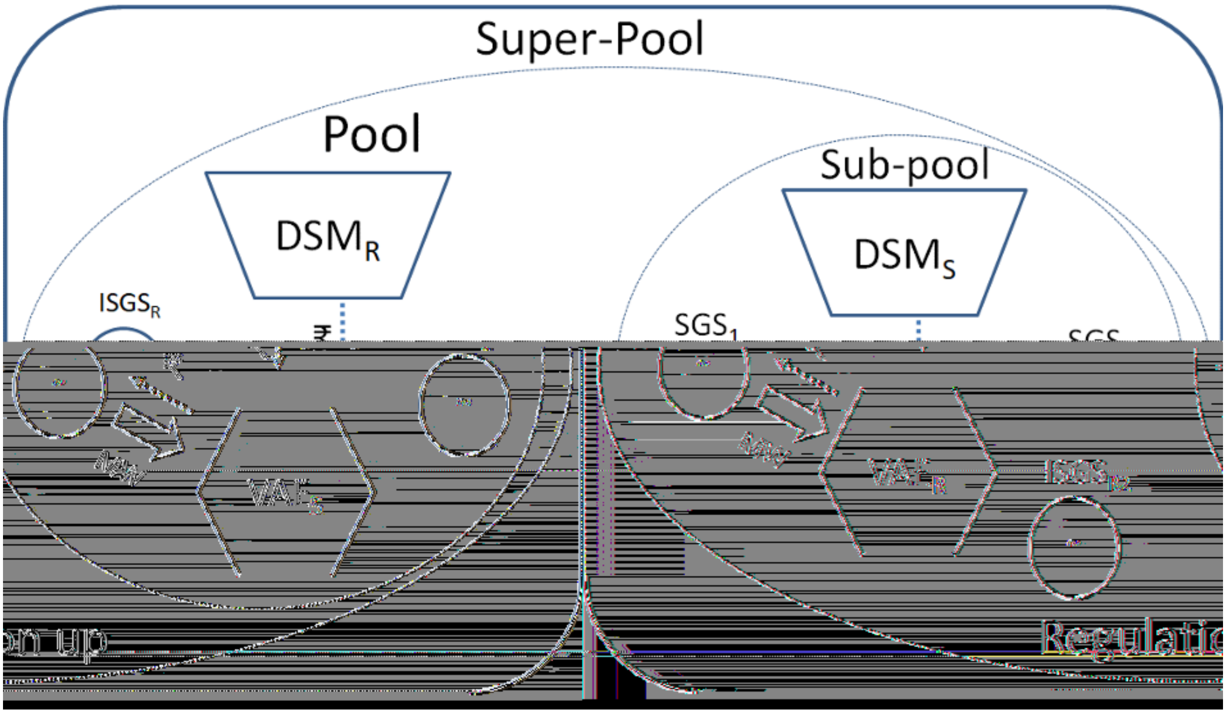


Figure 26: Regulation up service in nested control area

8.20. Information and Communication Technology infrastructure

Assessment, visualization and dispatch of reserves shall be through a robust and versatile optimization algorithm. A reliable and path redundant communication channel shall be provided for ensure the delivery of dispatch instructions the ancillary service providers in the electronic form. In addition, the reserves dispatch shall be posted transparently on the SLDC website for ease of access of the concerned stakeholders.

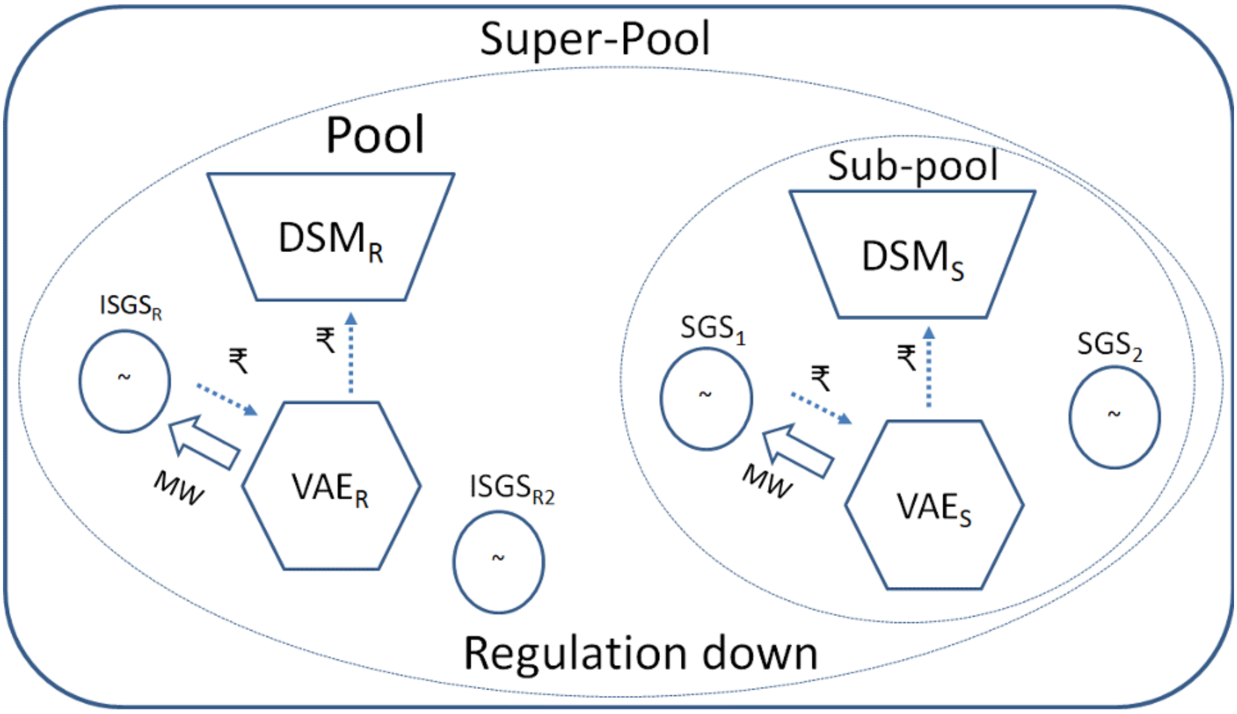


Figure 27: Regulation down service in a nested control area

8.21. Transmission charge and loss administration

Philosophy for application of transmission charges and of transmission losses for the reserves despatched shall be declared in advance. There shall be no post facto truing up transmission charges and losses.

8.22. Capacity building

Suitable initiatives for capacity building in the market simulation, optimization techniques, harnessing of flexibility attributes, reserve assessment and ancillary service shall be taken up in collaboration with industry experts, academia and Forum of Load Despatchers.

8.23. Regulation for intrastate reserves and ancillary services

The draft model regulation for intrastate reserves and ancillary services is enclosed as **Annex-VI**. The regulations could suitably consider deployment of lift irrigation schemes and pumped storage hydro stations under the ancillary services. The procedure for assessment, monitoring, despatch and settlement of reserves shall be prepared in consultation with all stakeholders and approved by the State Electricity Regulatory Commission.

8.24. Periodic review of the progress of implementation

An appropriate committee may be constituted for monitoring the progress of implementation of the recommendation in different States. The committee may provide guidance and enable hand-holding through experience sharing across different States.

9. Road map

The suggested roadmap for implementation of the intrastate reserves and ancillary services is as below:

Table 14: Suggested roadmap for implementation

S No.	Activity	Cumulative time (from zero date)
1	Stakeholder workshop on the SANTULAN report and the Model regulations by SLDC	**15 days**
2	Draft amendment of intrastate Grid Code by SERC for maximum scheduling limit, technical minimum, ramp rate for generating units etc. by SERC	**30 days**
3	Notification of the amendment after stakeholder discussion	**90 days**
4	Publication of the draft regulations on reserves and ancillary services for intrastate grid based on the Model regulations	**100 days**
5	Notification of the regulations on reserves and ancillary services for intrastate grid	**160 days**
6	Submission of a procedure for implementing intrastate reserves and ancillary services by SLDC after stakeholder consultation	**190 days**
7	SERC approval of the Procedure for intrastate reserves and ancillary services after stakeholder consultation	**210 days**
8	Procurement of hardware and development of software by SLDC	**300 days**
9	Furnishing details to SLDC by intrastate reserves and ancillary service providers	**330 days**
10	Go live	**365 days**

The above timeline is only indicative. The actual implementation would depend on the available resources and State specific constraints.

“***An error does not become truth by reason of multiplied propagation, nor does the truth become error because nobody will see it***”-Mahatma Gandhi

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Annex-I: Constitution of the sub-group

FORUM OF REGULATORS (FOR)

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Telefax Nos. : 011-23353503/23753920

No.1/14/2015-Reg.Aff.(FSDS)/CER Dated: 22.02.2019

Subject: Constitution of Sub-Group on 'Reserves and Ancillary Services at State Level' under FOR Standing Technical Committee

Reference discussion during the 22nd Meeting of the Standing Technical Committee for "Implementation of Framework on Renewables at the State Level" held on 1st November 2018 at New Delhi, wherein it was decided to constitute a Sub-Group for pilot on Reserves and Ancillary Services for the States. It was also decided that the pilot project could be initiated without waiting for State Regulations on the Reserves and Ancillary and CERC regulation can be used for reference for Pilot Project.

2. Accordingly, a sub-group on 'Reserves and Ancillary Service at State Level' of the Standing Technical Committee of the Forum of Regulators (FOR) is hereby constituted with the following composition:-

1. Shri S.K Soonee, Advisor , POSOCO, - Chairman of the sub-group
2. Representative of GERC (Gujarat) - Member
3. Representative of MERC (Maharashtra) - Member
4. Representative of MPERC(Madhya Pradesh) - Member
5. Representative of TSERC(Telangana) - Member
6. Chief Engineer, SLDC Gujarat - Member
7. Chief Engineer, SLDC Maharashtra - Member
8. Chief Engineer, SLDC Madhya Pradesh - Member
9. Chief Engineer, SLDC Telangana - Member
10. Executive Director, WRLDC, Mumbai - Member
11. Executive Director, SRLDC, Bengaluru - Member
12. Representative of NLDC, New Delhi - Member
13. Representative of CERC/FOR, - Member/Convener

3. The Terms of Reference of the Sub-group are as under:-

i. To disseminate the learning from the experience of implementing the reserve regulation ancillary services and fast response ancillary services at the interstate level and recommend the roadmap for implementing similar mechanisms at the state level.

ii. To recommend the model regulations for harnessing the flexibility attributes, maintaining the mandated reserves and deploying them under normal and contingent scenario through intra-state reserve regulation ancillary services.

i.

iii. Any other recommendation as deemed fit in the context.

4. The sub-group may co-opt any other member, as deemed fit.

Yours Faithfully,

Sd/-

(Rashmi Somasekharan Nair)

Deputy Chief (RA)

Copy to:

Members of the Sub-Group (as above)

Copy for information to:

PPS to Chairperson, CERC /FOR

Sr. PPS to Secretary, CERC

PS to Joint Chief (RA)

Annex-II: Consolidated discussion summary of subgroup meetings

1st meeting- 06 May 2019, NLDC New Delhi

1. Advisor (RE), CERC, as Member-Convenor, welcomed the participants to the meeting. It was highlighted that the regulatory framework on reserves and ancillary services at inter-state level have facilitated secure and reliable system operation. The regulatory framework on reserves and ancillary services are also required to be implemented at intra-state level which would facilitate better and flexible system operation, especially in case of renewable rich states.
2. The chairman of the sub-group gave a brief background on the constitution of the sub-group and stressed on the need for Reserves and Ancillary Services in large grids like India. The sub-group would focus on harnessing reserves at state level with appropriate settlement mechanisms. While report preparation is one of the tasks, the sub-group would attempt to create, test and implement a real-time on-the-ground pilot on reserves and ancillary services in some of the states.
3. The Chairman of the sub-group read out the ToR and sought suggestions to co-opt any other expert(s) in the sub-group. SLDC (Guj.) representative opined that a member from academia may be co-opted. The Chair also suggested co-opting Sh. S K Chatterjee JC(RA), CERC as an expert in market design aspects to which all members agreed. Further, Ancillary Services are being increasingly recognized as Essential Reliability Services world-wide and accordingly, Ancillary Services may be renamed as “Essential Reliability Services”. These suggestions were agreed to by all the members.
4. A presentation was made by member representative from NLDC, POSOCO regarding experience gained in implmentation of Reserve Regulation Ancillary Service (RRAS) and Fast Response Ancillary Services (FRAS). A copy of the presentation is attached at **Annex – 2**. The main points presented include, inter-alia, System Balancing Continuum, Key Statistics, Analysis of RRAS & FRAS Despatch Instructions, Frequency Improvement, Real Time Case Studies and Key Learnings.
5. The key design needs for implementation of reserves/ancillary services were recognized as follows:
    - Tariff of Intra-state Generation Plants (Single-part/Multi-part)
    - Mechanism for Declaring Capability, Ramp Rates, Technical Minimum
    - Scheduling and Despatch
    - Imbalances and Settlement thereof
    - Computation of Reserves Quantum
    - Compensation Mechanism for Reserve

- Incentive/Mark-up
- Settlement Systems
- Recovery for Sustainable Mechanism

6. In the context of FRAS from hydro, it was mentioned that intra-state hydro stations have water release and other constraints as per irrigation requirement and there may be difficulty in participation in ancillary services. The Chair clarified that after satifsfying all constraints, we can try to harness the flexibility of hydro. There is a need for mathematical formulation and validation of all legacy constraints. The computation and visualization of reserves (DC_on bar minus Schedule) in real-time is the starting point. There is a need for dashboard for the operator to see the merit order stack, up reserve, down reserve, maximum ramp up, maximum ramp down etc.
7. The member representative from Gujarat, SLDC made a presentation on state level ancillary services. The copy of the presentation is placed at **Annex – 3.** It was mentioned that SLDC may be appointed as Nodal agency for implementation. Nodal agency may be empowered to operate/trigger Ancillary services in pre-specified conditions.
   - All the state generating stations to be covered under this mechanism.
   - Generator to declare Fixed and Variable cost
   - Common merit order to be prepared and displayed on the website for the ancillary services.
   - Ancillary services be triggered based on merit order except in case of transmission constraints.
   - Hot and Cold reserves may be used as per requirement.
   - In case of original beneficiary requisites URS back, then schedule under ancillary may be dispatched from the next generator as per merit order for ancillary services,
   - In case of specific scheduling under ancillary service, that particular entity has to pay all (FC + VC) charges. FC to be compensated back to the original beneficiaries.
   - In case of settlement through the pool, generator may be paid FC+VC. FC to be compensated back to the original beneficiaries.
   - In case of backing down, generator need to pay to pool @ VC to the extent of backing down.
   - Technical minimum requirement of generation to be ensured.
8. The member representative from GERC opined that common merit order would have to be prepared for the state as a whole including MPPs/IPPS. The member representative from MPERC stated that provisions in PPAs may have to be factored as the tariff is not determined/adopted by the ERCs. The member representative from SLDC Maharashtra enquired on payment of variable charges to the pool upon backing down by the generator.

Advisor (RE), CERC stated that part load compensation would also have to be factored. The ambit of ancillary services could be expanded to include Demand response and Energy storage in future. The member representative from SLDC, Gujarat suggested that this pilot on ancillary services would pave the way forward for integration of battery storage in the future.

9. The Chair emphasized that reserves/ancillary services have many flavours and variations worldwide. As a first step, computation of reserves available is required to be done based on Declared Capability, Schedule and Technical Minimum. Further, the quantum of despatchable reserve is limited by ramp constraints.
10. The member representative from SLDC, Telangana made a presentation to the sub-group. The copy of the presentation is placed at **Annex – 4.** The salient points were as follows:
    - The tariff of Intra-state generation plants is two part i.e. Fixed Charges and Variable charges
    - All intra state generators are declaring availability block wise on Day Ahead Basis. Revised availability declaration duly considering the tripping / Synchronization of units is being furnished by the Generators.
    - Reserve assessment is based on trend analysis (previous day, weather forecast and day of the week) load forecast on day ahead basis is carried out. The total availability considering the declarations furnished by all the generators (LTA & MTOA) is assessed along with quantum of power available from all Short term contracts. Hydel availability is also assessed considering any discharge instructions issued by KRMB.
    - There is no separate mechanism for Harnessing Reserves in the State. Load Generation Balance is being carried out as per existing IEGC and State regulations.
    - 500 MW Spinning Reserve is being maintained to meet any contingency in the form of hydro generation when Hydro resources are available.
    - When Hydro resources are not available , spinning reserve is being maintained in the form of back down of thermal generators as per Merit Order.
    - During surplus power conditions pumping mode of operation is being carried at srisailam and Nagarjuna’sagar hydel stations. It is being utilised during peak demand period and contingencies.
    - Settlement of intrastate generators is being carried out through a mutual accepted procedure which is approved by TSERC. There is no separate incentive mechanism for despatch of Reserves.
11. The member representative from SLDC, Telangana emphazized that there is need for ABT at intra-state level. Advisor (RE), CERC enquired about inter-state banking contract under overarching agreement. SLDC, Telangana stated that this arrangement was used on few occassions with bilateral contracts through RLDCs.

12. ED, WRLDC highlighted that in view of ABT mechanism in place in states of Gujarat and MP, there is a clear case for a pilot project. Maharashtra would also have ABT from 2020 onwards and hence, it would also be able to operationalize in future. ED, SRLDC stated that there is no ABT implementation in any of the five states of southern region.
13. The demonstration of reserves under RRAS and FRAS was made by member representative from NLDC, POSOCO. The Chair emphasized the need for similar mechanism for computation of reserves. The need for primary reserves was also emphasized.
14. The Chair observed that there are international standard techniques for reserve assessment and compensation. It was agreed that international literature survey would be carried out. Gujarat, SLDC volunteered to prepare a questionnaire on various aspects of reserves and ancillary services. The Chair emphasized the need for actual control room experience with implementaion of a pilot project in any of the willing states. The member from Gujarat SLDC graciously offered to host the next meeting at SLDC, Vadodara in the last week of May, 2019.
15. **Key Decisions Taken**
    - All member representatives to be added in SANTOLAN WhatsApp and Google groups to facilitate smooth communication.
    - SLDC Gujarat to prepare a questionnaire for survey of states regarding reserves & despatch.
    - Generators views/suggestions to be invited in the series of meetings in States.
    - A representative from Academia and Dr. S K Chatterjee, JC(RA), CERC to be co-opted as experts.
    - Next meeting to be held in last week of May, 2019 at Vadodara, Gujarat.

2nd meeting - 07 Jun 2019, SLDC Gujarat

1. The Second meeting of the sub-group on 'Reserves and Ancillary Services at State Level' was held on 7th June 2019 under the Chairmanship of Shri S. K Soonee, Advisor, POSOCO. At the outset the member convener and Advisor (RE), CERC welcomed all the members and participants connected over VC from NLDC, SLDC Maharashtra, SLDC Madhya Pradesh, SLDC Telangana, SRLDC Bangalore and WRLDC Mumbai to the 2nd meeting of the FOR technical committee sub-group. The Member Conveyor thanked Chief Engineer (SLDC), Gujarat for organising the meeting and conveyed special thanks to the Member, GERC, Director (MERC) and Director (MPERC) for gracing the occasion with their presence. The meeting started with review of progress since the first meeting and the following points were deliberated
2. **Confirmation of the minutes of the first meeting:** The minutes of the first meeting held on 06.05.2019 were confirmed by all members.
3. **Progress review**:

(1) It was informed by the Chairman that as per the decision in the first meeting Shri S K Chatterjee, Chief (RA) CERC and Professor Abhijit Abhayankar, IIT Delhi had been co-opted in the sub-group.

(2) It was intimated by CE, SLDC Gujarat that survey questionnaires have been circulated by SLDC Gujarat & filled by SLDC Madhya Pradesh.

(3) NLDC informed that the basic information on intra-state generators (Installed capacity, Pmax, Pmin, Variable charges) had been received from SLDC Gujarat & SLDC Madhya Pradesh.

4. **Chairman of the sub-group** emphasized on the need for taking up a pilot project in Western Region to create a success story and pave way for formulating the regulations for intrastate reserves and ancillary service. He also mentioned that the learning derived from the interstate level could be used by the States to leapfrog. The introductory presentation given by the Chairman is enclosed as **Annexure-2**.

The following points emerged to plan out the future course of action:

i. What is the tariff structure of intra-state power stations?
ii. What is the mechanism for conveying information on Declared Capability (DC) by the power stations to SLDC for scheduling?
iii. Is the fixed charge (FC) recovery linked with plant availability factor (PAF)?
iv. Can the PAF be verified by SLDC through the DC submitted by the generators?
v. What is the mechanism for imbalance handling & settlement within the state?
vi. Is there any intra-state regulation on computation & despatch of spinning reserves?
vii. How is the intra-state reserve being computed?
viii. Is the operator able to see the trend of reserve available for next few time blocks?
ix. Is operator confident as to how much reserve is to be pressed in to service?
x. Is operator able to assess the cost of these reserves?
xi. Is there a settlement system to pay for the reserve, utilised or unutilised?
xii. Is there a mechanism to establish that the most economic operation is followed?
xiii. Should we have a mechanism for compensating the power station for reserves?
xiv. Should we have a cost recovery mechanism for ensuring long term sustainability of the essential reliability services viz. reserves?
xv. Should there be any incentive to generators for providing reserves?
xvi. Should there be a formal mechanism to replenish the depleted reserve?

Basic Data

The basic set of data required for computing & monitoring intra-state reserves at SLDC was discussed & it emerged that the following information must be made available at SLDC for every time block for each power station:

(1) Declared capability in MW

(2) Declared capability on-bar (in MW)
(3) Schedule in MW
(4) Pmax = On bar installed capacity – Normative Auxiliary Consumption (in MW)
(5) Pmin = Technical Minimum generation (in MW)
(6) Variable charge (VC) in Rs/Kwh
(7) Ramp-Up rate in (%age of on-bar Capacity) per minute
(8) Ramp-down rate in (%age of on-bar Capacity) per minute

Derivable parameters:

Based on the above base data, certain derived parameters could be computed & monitored for each time block as under:

- Regulation Up-reserve = On bar installed capacity – Schedule (fig. in MW)
- Regulation Down-reserve = Schedule – Technical Minimum (fig. in MW)
- Cold reserve = DC – DC on bar …. (in MW)
- Hot spinning reserve = DC on bar – Schedule ….(in MW)
- Despatchable reserve = Minimum (Hot spinning reserve & Regulation Up Reserve)

5. **GM NLDC** presented a sample optimisation module using 'MS Excel Solver' based on some basic data for intra-state generators of Gujarat. The solver used the objective function of minimising production cost while honouring all extant technical & commercial constraints as under:
   - Objective Function:$\sum \boldsymbol{Schedule * VC = Minimum}$
   - Equality Constraint(s): ***Total schedule = Total demand of the state***
   - Inequality constraint(s): ***Pmin ≤ Station schedule ≤ Pmax;***
6. **CE, SLDC Gujarat** appreciated the algorithm based approach toward reserve computation & despatch. He suggested that the sample excel solver sheet may be shared by NLDC team with SLDCs for further exploration and customization.
7. **CE SLDC Telangana** stated that all the data would be shared for initiating the pilot project on optimization. He also offered to provide IT support. He suggested that implementation of SAMAST should be pursued in all States.
8. **Notification of Technical Minimum of coal fired Generating stations**

   Concerns were raised by State representatives regarding part load operation of old/small-size thermal units and compensation for degradation of station heat rate, auxiliary consumption, and secondary fuel oil consumption. Concerns were also raised with regards to inadequate support from OEMs for flexible operation.

   CE, SLDC Maharashtra stated that enabling regulatory framework is required for reserves and ancillary in the state level.

ED, WRLDC emphasized that notification of technical minimum norms for intrastate generators in line with CERC regulations is the first step for implementation of reserves and ancillary services. He proposed that a uniform approach could be adopted initially and exceptions could be dealt separately on case-to-case basis by the appropriate commission. Chairman, shared that flexibilization of coal-fired units has become a key agenda globally. WRLDC representative shared the performance of central sector thermal units of 210 MW, 500 MW, 660 MW and 830 MW units over the last one year to demonstrate successful part load operation of those units.
Addl. CE, SLDC Madhya Pradesh stated that technical minimum level needs to be mandated in the regulations for wider acceptance.
Director MPERC opined that detailed methodology could be provided in the procedure.

After deliberation it emerged that either the technical minimum level should be lowered or the machines would be required to perform two shift operations. It was decided that all technical constraints of the generating units should be factored in the optimization model that was being developed.
Member GERC stated that procedures could be developed by the respective SLDCs based on the regulations notified by the appropriate Commission.
ED, SRLDC stated that mock exercise could be taken up in MS Excel to start with.
Director, MERC stated that deviation settlement mechanism, merit order despatch, technical minimum levels and compensation mechanism must be harmonized for implementation of intrastate reserves and ancillary services. He requested for devising a common philosophy for all States.

9. Other inferences drawn from the deliberations:
   i. Intra State reserve and ancillary services mechanism presupposes implementation of intrastate ABT and SAMAST framework
   ii. Ramp-up / Ramp down constraints were the key limiting constraints during the implementation of SCED (security constrained economic despatch at central level).
   iii. CERC (Terms & Conditions of tariff) Regulations have devised specific norms for ramping services from thermal generators.
   iv. Merit order stack should be visible to the operators in real time for despatching. Post facto moderation in the MOD stack would defeat the purpose.
   v. Quantum of reserves requirement would vary from State to State
   vi. Well defined norms for technical minimum and compensation, Scheduled based payments and double entry system through a Virtual Ancillary Entity could simplify scheduling and settlement of reserves

vii. Adoption of causer-pays principle would enable the Intra-State pool account be self-sustainable
viii. Weekly settlement of ancillary despatch is desirable.
ix. Adequate provision for IT, communication infrastructure and HR resources is essential
x. Inclusion of stations multi-purpose shared hydro stations and gas fired stations having multiple modes of operation (Open cycle, combined cycle) and multi-fuel options (APM, NAMP, RLNG, Liquid) would increase the complexity of the optimization model. Hence, inclusion of gas and hydro stations could also be considered after gaining some experience with optimization of coal fired stations.

10. Constitution of working groups at SLDCs

CE, SLDC suggested constitution of teams for experimenting with the optimization model developed by NLDC.

11. It was decided that teams comprising of members conversant with scheduling, commercial regulatory, IT could be formed in the respective SLDCs to run the optimisation module for the respective state. The team could then share their feedback with the sub-group.
12. It was also decided that the team would carry out gap analysis for different States on the following aspect:
    - Tariff Structure
    - Scheduling & Despatch, Imbalance
    - Declaration of technical parameters & variable charge
    - Reserves – Mandate, availability, computations, despatch,
    - Metering, Accounting & Settlement Systems
    - Sustainable recovery & payment mechanism for reserves, any incentives
    - Availability of technology platform
    - Manpower adequacy, skillsets needed

13. **Schedule for Next Meeting**

It was decided that the 3rd meeting would be help in July 2019 at Jabalpur and the 4th meeting would be tentatively held in August 2019 in Maharashtra.

14. Member convener thanked Chairman, all members of the sub-group and other participants for their contribution in the meeting.
15. The meeting ended with a vote of thanks to the Gujarat SLDC.

3rd meeting- 26 Jul 2019, SLDC Madhya Pradesh

1. The third meeting of the sub-group on 'Reserves and Ancillary Services at State Level' was held on 26th July 2019 under the Chairmanship of Shri S. K Soonee, Advisor, POSOCO. At the outset, Chief Engineer (SLDC, Jabalpur) formally inaugurated the meeting. The member convener and Advisor (RE), CERC welcomed all the members and participants connected over

VC from SLDC Maharashtra, SLDC Gujarat, SLDC Telangana, SRLDC Bangalore and WRLDC Mumbai to the 3rd meeting of the FOR technical committee sub-group. The Member Conveyor thanked Chief Engineer (SLDC), Madhya Pradesh for organising the meeting.

2. **Confirmation of the minutes of the first meeting:** The minutes of the second meeting held on 07.06.2019 were confirmed by all members.

3. **Chairman** of the sub-group gave a briefoverview of the progress made so far. He expressed satisfaction over the work done by SLDC Jabalpur & SLDC Gujarat viz. constitution of internal teams with SLDC to work on schedule optimisation using excel solver. He commended the active involvement of SLDCs in recent past in bringing out some key documents viz. the SAMAST and the CABIL reports under the aegis of the Forum of Regulators (FOR) which provided a robust framework for implementing major reforms at intra-state level. He said that the next desirable step could be devising a mechanism for causing overall economy at state-level. He expressed that reserves & flexibility in conventional generation are key ingredients for successful integration of renewables, for which the following points would be necessary:
    - Groundwork for implementation of framework for reserves at intra-state-level factoring all state-specific constraints
    - Pilot implementation for creating a success story
    - Inter-SLDC groups for optimization to cause economy
    - Academia support for learning the fundamentals & latest tools
    - Procurement of optimization software viz. GAMS
    - Sanctity of variable charge computation should not act as a hinderance
    - Information on ramping capability is a vital input for reserve assessment
    - Identifying other states which could be taken in fold so as to give feed-back to regulatory commissions for necessary intervention

    ED SRLDC proposed to consider co-opting KarnatakaSLDC as a member for implementation of intra-state reserves & ancillary services. It was agreed to send a formal invitation to SLDC Karnataka in this regard.

    Chief Engineer, SLDC Gujarat expressed that SLDC Gujarat team shall prepare a draft model regulation for operationalisation of reserves and ancillary at state level. The same would be shared with the sub-group for further refining & finalisation. Presentation made by Gujarat SLDC during the meeting is attached as **Annexure –III**.

4. **GM, NLDC** informed that a google form based online survey portal has been created with help of the questionnaire shared by SLDC Gujarat in previous meeting. The online survey could be remotely filled by the members with help of the following web-link: https://forms.gle/zZ8r4NdPJayqzXow5.

He also expressed that the operational experience of security constrained economic dispatch (SCED) at national level shall be shared with the members.

Chief Engineer SLDC Gujarat urged all members to share their input (if any) on the survey questionnaire so as to finalize & freeze the survey form.

5. **Shri Vivek Agarwal, EE SLDC** Madhya Pradesh gave a presentationon 'intra-state generation tariff, forecasting, scheduling, merit order dispatch (MOD), intra-state reserves, unit-commitment criteria, metering & settlement system etc. prevalent in the state of Madhya Pradesh. (**Annexure-II**) Key highlights of the discussion are summarized below**:**
   a) MPERC (Terms & Conditions of Tariff) Regulations 2015 is the guiding regulation for intra-state generation tariff. MPERC determines tariff of intra-state generators, IPPs vide MYT orders.
   b) A 2-Part tariff structure comprising of fixed charge (FC) & variable charge (VC) is in place in Madhya Pradesh.
   c) SLDC computes & certifies plant availability factor (PAF) & scheduled energy on monthly basis for payment of FC & VC respectively to intra-state generators
   d) Monthly PAF computation is linked to DC as given under:

$$\mathbf{PAF = 10000 \times \sum_{i=1}^{N} DC_i \,/\, \{ N \times IC \times (100\text{-}AUX_n) \}\%}$$

   Where,

   IC = Installed Capacity of the generating station in MW,

   DCi = Average declared capacity (in MW) for the ith day of the period.

   N = Number of days during the period, and

   AUXn = Normative Auxiliary Energy Consumption as a %age of gross generation;

   e) MOD is prepared by the holding Distribution Company (MPPMCL) based on VC as per latest (last month's) bill issued by the state generators. MOD is submitted by MPPMCL to SLDC on monthly basis by 10^{th} -15^{th} day of every month. The VC of ISGS stations used in MOD preparation factors in the point of connection (POC) transmission loss component.
   f) Scheduling is done as per MP State Grid Code (MPEGC) and Balancing and Settlement Code (BSC) 2015
   g) All power allocation from Government are made to MPPMCL. MPPMCL re-allocates the power among the 3 state DISCOMs based on day-ahead demand forecast for each time block. There are no private DISCOMs in the state. MPPMCL is allowed to revise the allocation to the state-DISCOMs on the actual day of operation based on load-generation balance requirement. MPPMCL runs the MOD and unit commitment (UC) software.

During low demand period reserve shut down decision is taken by MPPMCL in consultation with MP-SLDC.

The Chairman said that unit commitment decisions are being presently taken heuristically and a more rigorous and scientific approach for unit commitment would be desirable in future.

ED WRLDC, expressed that MOD preparation should be coordinated by SLDC. Since presently there is no private DISCOM in MP, MOD preparation by MPPMCL is going on smoothly. However, in future with IPPs & private DISCOMs entering the intra-state market, a neutral body viz. SLDC would be required to prepare the intra-state-MOD.

h) As per 20th FOLD recommendations, SLDC MP has engaged Indian Institute of Information Technology, Jabalpur for Development of a load forecasting model for daily, weekly, monthly, seasonal and annual load forecasting. Weather data from RLDC/NLDC would be desirable for better forecast.
   Chairman of the Sub-Group expressed that load & RE forecasting need to be done by SLDC for grid security & by MPPMCL for containing deviation & associated commercial implications.
   ED WRLDC suggested that it would be prudent to take input from multiple professional weather forecast service providers in stead of being solely dependent on IMD. He commended the initiatives taken by Madhya Pradesh in handling imbalances by taking 1-2 MW golden share in ISGS stations of NR which they use for managing imbalances by availing URS during contingency.

i) **400-500 MW** reserve is always maintained by under-requisitioning in hydro & thermal stations for meeting contingency during real time operation. Reserve availability in ensuing blocks is manually computed by real time shift engineers.

j) Hydro generators are out of the ambit of ABT & MOD. SLDC-MP dispatches hydro based on grid conditions. Renewable generation is treated as must run & their variability is handled by dispatching reserve margin available in hydro power stations.

k) Intra-state ABT has provided for meters at each T-D(transmission-distribution) inter-face point. Presently 1081 inter-face energy meters are in place in the state. Deviation (DSM) and reactive energy (RE) charges for intra-state entities are computed based on main meter data.

l) AMR system is in place at each interface point (G-T, T-D) & at SLDC which facilitates meter-data downloading at SLDC. Missing meter data is retrieved using local meter reading instruments (MRI) & sent by mail upon intimation by SLDC on monthly basis.

CE, SLDC MadhyaPradesh said that redundancy in energy meter data & SCADA data is essential. He stated that based on a recent review of state grid code (MPEGC 2005) under leadership of MP-SLDC, State Commission (MPERC) has notified MP Electricity Grid Code 2019 on 21st June 2019 which has addressed several issues raised by SLDC-MP. The new state grid code has provisions for check meters in addition to main & standby meters. He informed that norms for **technical minimum** generation level have been specified by MP-ERC for the intra-state generators**.**

MP Power Generating Company (MPPGCL) representative said that new units of 250 MW and above size are capable of operating at 50% of capacity.

m) Procurement of check meters & meters capable of recording at 5-minute interval are being taken up with MPPTCL. PSDF funding approval has been obtained for the same.

n) State energy accounting (SEA) is being done by SLDC in a dispute-free manner since 2009. SLDC has started deviation charge computation for 10 MW & above wind generators and 5MW & above solar generators since Aug 2018 following the MP-ERC notification of DSM regulations for intra-state Wind/solar plants.

Chief Engineer SLDC-MP stated that Intra State Deviation pool was changed from non-zero to zero sum pool due to accumulation of surplus amount.

6. Case studies on Optimization

An excel solver module for generation cost optimisation was shared by GM NLDC in the 2nd meeting on which SLDC Madhya Pradesh & SLDC Gujarat representatives did further customisation in consultation WRLDC team. They shared a number of case studies based on their experience with the Solver Module. The members commended the efforts taken by MP-SLDC & Gujarat SLDC teams in running the optimisation module and expressed satisfaction at the sample results. The solver output gave vital information viz. system marginal price, optimised generation cost for each representative time block.

Inference from the discussion on Solver Case studies:

- MS Excel Solver could be used for day-ahead purchase decisions, ancillary despatch, economic despatch, estimation of reserve carrying cost.
- The optimization results could be converted into graphs for comprehension
- Database is required to save various scenarios and their results
- Following steps would be involved for running the Solver model for 96-time blocks: - *fetch data from the scheduling Software > Run Solver Model > Push the results back to the scheduling s/w;*
- Reliability of communication system would be critical for continuous & automatic operation of the optimization program

- Despatchable reserves is limited by ramping constraints, hence reserves need to be distributed over multiple units. Having more units on bar helps in improving the despatchable reserves volume.
- For realistic results, the must run stations (wind/solar/run-of-the river hydro) and must take (STOA) contracts could be kept out of optimization module by making Pmax = Pmin.

  It was appreciated by all members that this tool can be effectively used for decision making on day ahead basis on matters like taking units under RSD, planning for short term power procurement.

GM NLDC suggested that the current level of familiarisation with Solver module needs to be scaled up to the next level to run it continuously for all 96 blocks in a day; to factor in several other constraints; under-standing higher concepts viz. infeasibilities etc. He suggested that more powerful database software like MySQL, Mongo.db, etc. could be used along with python / visual basic scripts for further automation of the process. He expressed that the experience of NLDC team in running in-house optimisation engine for SCED implementation could be gainfully utilised by the members. He demonstrated the different out-puts and displays of the SCED software to explain the visualisation tools that would be necessary for reserve monitoring. He agreed to share some basic reference material on Optimisation techniques and the General Algebraic Modelling System (i.e. GAMS). He advised to refer to solver manuals (available at solver.com) for more insight on different terminology and other solver add-ons. The members of the Sub-Group suggested that a training session on optimisation using GAMS may be facilitated by POSOCO.

7. Suggested Regulatory interventions

It was suggested that the following Regulatory Interventions would be necessary for implementing Essential Reliability Services at state level.

- Notification of Technical minimum generation level
- Notification of ramping capability norms for generators
- Notification of methodology for computation of Variable Charges
- Notification of Regulations for intra-state ancillary services
- Notification of spinning reserves to be maintained at State level
- Amendment to intra- state open access (OA) regulations in line with CERC amendments to inter-state open access regulations.

CE, SLDC-MP stated that a detailed report for AGC implementation (at Shri Singhaji TPS) is being prepared by SLDC which will be submitted to MPERC for approval. He informed that MPERC is examining for resolution of some issues raised by qualified coordinating agencies (QCAs) and RE generators through suitable amendment in intra-state RE-DSM regulations.

The **Chairman** informed that another sub-group constituted under FOR Standing Technical Committee is working on roles & responsibilities of QCAs for RE integration.

8. Other inferences/discussions

a. Computation on Variable charge of thermal generators by different states need to be examined. VC is a quadratic function & depends upon factors viz. station heat rate, gross calorific value, auxiliary energy consummation, secondary fuel oil consumption etc. The document of CEA on this topic could be a good reference material.

b. Scientific approach based on algorithmic solutions is desirable for reserve computation & monitoring.

c. The following basic capability would be required for running & monitoring optimized dispatch: (i) Familiarity with state power system (ii) Fundamentals of resource optimization (iii) Optimization software (iv) Software interface for front line operators (v) Database management

9. Decisions taken for future work:

The following action plan was decided for the ensuing months:

- More case studies to be done in MS Solver
- Must run stations / Must take contracts to be excluded from optimization module
- Net load Forecast to be considered instead of Demand forecast
- Inter SLDC-RLDC working teams to be formed to work on the optimization modeling
- Free version of GAMS to be downloaded
- Transmission constraints to be considered in the optimization model
- GAMS manual to be circulated by NLDC
- Capacity building workshop to be planned by NLDC

10. Schedule for Next Meeting

It was decided that the 4th meeting would be help in August 2019 at SLDC Maharashtra.

11. Member convener thanked Chairman, all members of the sub-group and other participants for their contribution in the meeting. The meeting ended with a vote of thanks to SLDC Madhya Pradesh team.

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4th meeting- 30 Aug 2019, SLDC Maharashtra

1. The fourth meeting of the sub-group on 'Reserves and Ancillary Services at State Level' was held on 30th August 2019 under the Chairmanship of Shri S. K Soonee, Advisor, POSOCO. At the outset, Chief Engineer (SLDC, Maharashtra) welcomed the Chairperson, Director MPERC (Shri G Tiwari) and Dy Director-Technical MERC (Shri A. Khandare) & other members and participants to the meeting. The member conveyor thanked Chief Engineer (SLDC), Maharashtra for organizing the meeting. The Chairperson acknowledged the active interest

& participation of SERC members / staff and the heads of SLDCs in various sub-group meetings. He expressed that the presence of SERC staff would add value to deliberations of the sub-group. Other participants joined the meeting over VC from SLDC Madhya Pradesh, SLDC Gujarat & SRLDC Bangalore.

2. **Confirmation of the minutes of the 3rd meeting:** The minutes of the third meeting held on 26.07.2019 were confirmed by all members.
3. **Chairman** of the sub-group gave a briefoverview of the progress made so far and said that the sub-group shall demonstrate the results in the form of successful pilot projects while the report would be a biproduct of the experience. He commended the hard work done by the internal working groups in SLDC-MP, Gujarat & Maharashtra in understanding & running the solver-based optimization tool which marked synergy & convergence of ideas. He expressed that the success of security constrained economic dispatch (SCED) & fast response ancillary services (FRAS) pilot projects at national level has given the confidence to roll-out a doable framework at intra-state level by duly factoring all state-specific constraints & dynamics. It is the inhouse teams at SLDCs who understand the complexities & dynamics of the intra-state system better than any out-side vendor/consultant. Thus inhouse capacity building within SLDCs is imperative for moving further towards implementing a sustainable frame-work of intra-state reserves & ancillary services.

   He said that a 3-day tutorial in being planned to be conducted in Delhi in mid-September in association with academia for capacity development of the sub-group members and the young enthusiasts at SLDCs.

   GM NLDC informed that the 3-day tutorial s likely to be held during 12-14 September 2019 and the participants are expected to bring their cases & laptops for doing hands-on sessions after learning the basics on GAMS optimization module.

   Chief Engineer, SLDC Gujarat said that he recently attended a meeting at MoP wherein four states have been proposed for implementation of intra-state SCED viz. Gujarat, Karnataka, West Bengal & Uttar Pradesh (UP). Accordingly, it is desirable to rope-in SLDC Uttar Pradesh & SLDC West Bengal in the sub-group. He also expressed that SLDC Gujarat may be entrusted with the task of compiling survey responses on behalf of the sub-group.

   Addl. Chief Engineer, SLDC Madhya Pradesh proposed that the sub-group may consider roping in one SLDC from each region.

   After deliberations, it was proposed to co-opt members from following 3 SLDCs

   - SLDC Uttar Pradesh (NR)
   - SLDC West Bengal (ER)
   - SLDC Assam (NER)

It was proposed by member convener (and agreed by all) that the above matter could be proposed in the forth coming FOR technical committee meeting & based on their advice a decision would be taken.

4. **Shri Abinash Dhawade, Dy Executive Engineer, SLDC** Maharashtra gave a presentationon 'intra-state generation tariff, scheduling procedure, merit order dispatch (MOD), intra-state reserves assessment method, metering & settlement system etc. prevalent in the state of Maharashtra (**Annexure-II**) Key highlights of the discussion are summarized below**:**

Tariff Structure:

a) MERC (Multi-Year-Tariff) Regulations define norms for generation tariff in the state.
b) 2-Part tariff structure comprising of fixed charge (FC) & variable charge (VC) is in place
c) The tariff regulations have provisions for computation of plant availability factor (PAF) linked to DC declared by generators & plant load factor (PLF) linked to scheduled energy on monthly basis for payment of fixed charge (FC) & variable charge (VC) respectively to intra-state generators
d) SLDC computes & certifies PAF, PLF, scheduled energy and actual energy for all intra-state generators.

Scheduling & Despatch

e) Merit Order Despatch is the least cost approach to meet demand from the contracted capacity of the respective Distribution Licensee. MOD is prepared on day-ahead basis by SLDC based on VC as per the MERC guidelines. It was clarified that the VC considered for MOD preparation is the landed-up cost at state periphery. Further, it is a flat cost irrespective of generator loading & the nature of heat curve.
f) Decision on zero schedule / reserve shutdown (RSD) is taken by DISCOMs with 24 hours advance notice after consultation with SLDC. Minimum RSD period is 72 hours.
g) A new scheduling software (MiDss) developed by M/s. PRDC Bangalore is in operation since 01.01.2019.CE(LD), Maharashtra said that of cloud-based solution for an integrated scheduling accounting, settlement software has proven to be more cost efficient.

Reserve Assessment:

h) Presently, there in no regulatory mandate from SERC for reserve assessment. However SLDC monitors & dispatches incidental reserves available in the form of margin available in intra-state generators after running MOD program and the quantum margin created after generation backing down in real time, un-scheduled hydro generation, generation taken under RSD during low demand period etc.

Metering & Settlement system

i) Intra-state ABT is in place since August 2011 as per MERC order in case 42 of 2016. The imbalance settlement method is known as Final Balancing & Settlement Mechanism (FBSM). Unlike the CERC (DSM) regulations, the FBSM based imbalance settlement rate is linked to weighted average system marginal price. 1118 ABT meters capable of recording energy at every 15 minute are used for weekly settlement of deviations from schedules.9 DISCOMs & 9 merchant generators are covered under the FBSM. The state pool is a zero-balance pool by design.

Chief Engineer SLDC Maharashtra, said that:

- The MERC has notified intra-state DSM regulations (similar to CERC regulations) which would be effective from 1.4.2020.
- The MERC has notified a MOD guide line that mandates a spinning reserve of 660 MW (~ highest size generator in state) to be maintained at state level. However, more clarity is required whether to keep such reserve at a single generator or at multiple units in a distributed manner.
- Considering hydro generation as a reserve has certain limitations since the hydro projects are multipurpose projects which serve several obligations such as drinking water supply, irrigation etc. as mandated by respective water tribunals.

The Chairperson emphasized on the following aspects:

- Need for adopting a multi-part tariff comprising of FC, VC, Deviation charge, Congestion charge, mark-up for Ancillary Services etc. to factor all aspects of electricity market design.
- PLF calculation could be based on two aspects viz. scheduled energy & actual energy.
- A dedicated section in the report could be written on variable charge computation in states.
- Post the functioning of electricity markets, there is a need for thinking beyond MOD which is a legacy of the pre-market era and economy may be brought through optimization.
- Settlement system should be simple, implementable and dispute free.
- Keeping reserve is a role of system operator (viz. SLDC). It need to be booked to the pool (not to any specific state entity) and settlement is to be done with the pool. Spinning reserve in a power system is similar to the 'reserves & surplus' kept in financial books of accounts. Spinning reserve should be planned & kept by system operator such that it is dependable, distributed and duly factor the network constraints, generator ramp limitations, forecasting errors (error % would be different for RE rich & non-RE rich states).
- Operationalization of reserve & ancillary shall provide an opportunity for co-optimization of energy & ancillary.
- A clear mandate from SERC is necessary in this regard for enabling the SLDCs to keep reserves. Further, the SERC may classify the reserve as cold reserve, hot spinning

reserve, fast/slow reserve, ramp limited reserve, dispatchable reserve etc.to bring more clarity. Spinning reserve would always be preferred over cold reserve.

5. **Case studies on Optimization**

The solver based module which was developed & shared by GM-NLDC was used to run optimization cases by SLDC Maharashtra. They shared a number of case studies on different scenarios (viz. max demand, min demand, high RE, low RE etc.) and gave a comparative analysis on actual dispatch vs optimized dispatch in each case & summarized the results indicating overall economy achievable through optimization. The following table shows the summary of the cases which indicates reduction in average cost post optimization.

Cases	Production cost before Optimization	Production cost After Optimization	Total Saving	Average Cost before Optimization	Average Cost After Optimization	SMP rate
	(Rs Lakhs)	(Rs Lakhs)	(Rs Lakhs)	(Rs/Unit)	(Rs/Unit)	(Rs/Unit)
Case 1: Maximum Demand	515	484	31	2.54	2.49	3.29
Case 2: Minimum Demand	366	320	46	2.45	2.27	2.81
Case 3: Maximum Wind	375	350	25	2.47	2.31	2.96
Case 4: Minimum Wind	361	349	12	2.3	2.26	3.69
Case 5: Maximum Surrender	284	276	8	2.54	2.51	2.52
Case 6: Minimum Surrender	507	483	24	2.59	2.41	30

6. **Presentation by SLDC Madhya Pradesh:** Shri Rishabh Nayak, AE, MP-SLDC presented an advanced version of the solver module by running the optimization for all 96 blocks is a day in a sequential manner. He informed that AGC at intra-state level is being proposed for Shri Singhaji thermal power station in Madhya Pradesh. The members commended the efforts taken by SLDC internal teams in running the optimization modules and expressed satisfaction at the progress. Presentation given by MP-SLDC is attached as **Annexure-III**.

GM NLDC said that the current level of familiarity of SLDC teams with excel solver and appreciation of optimization results had effectively established proof of concept. It would be necessary to raise it to the next level by running optimization for all 96 blocks in one shot & doing it continuously for all time blocks. In block-by-block sequential running of solver the futuristic constraints viz. MWH limit for hydro, expected ramping during peak etc. may not be reflected correctly. Hence a multi-period continuous running of optimization would be desirable. Similarly, the current solver model won't be able to address issues like infeasibility This would require an advanced tool (viz. GAMS) since excel solver had several limitations viz. max. number of constraints etc.

Addl. CE (SLDC MP) informed that they had filed a petition before SERC for a zero balance DSM pool since managing huge pool surplus was a challenge since there is no PSDF counter-part for the state.

The Chairman of the sub-group stated that there are certain disadvantages of a zero balance pool viz. (i) lack of buffer for handling pool deficit scenario; (ii) fund constraints for rolling out any new reform mechanism by system operators viz. AGC, ancillary services; (iii) no latitude for doing system improvement viz. PMU/WAMS pilot project etc. Thus, it is preferable to have a positive pool balance by design. Excess surplus situation might be handled by having provision for ceiling. He stated that the next logical step would be planning out the modalities for pilot implementation of reserves in the states for which an order from SERC would be desirable.

Shri SS Patel, SE(SLDC-MP) said that additional resources & infrastructure (viz. hardware/software etc.) would be required for pilot implementation of intra-state reserves & ancillary services.

Director (Commercial), SERC Madhya Pradesh, said that it would be preferred if a petition is filed by SLDC in this matter. **Dy Director (Technical), MERC** also expressed similar concerns.

The Chairperson stated that it would be better if a suo-moto order comes in line with the CERC order on SCED by citing reference to the National Electricity Policy and CERC road map on reserves. GM NLDC stated that as envisaged in the Electricity Act, SERCs may initiate suo-moto petition for promoting market development towards causing overall economy.

7. **Draft Model Regulation: SLDC** Gujarat team shared a draft model regulation for intra-state reserves & ancillary services (copy enclosed as **Annexure-IV)**& the same was deliberated. The desirable features of the model regulation which emerged after the deliberation are summarized under:
   - The term Reserve need to be clearly defined & duly classified as fast, slow etc. Terms like MOD may be suitably replaced to avoid legal dispute.

- Co-optimization concept need to be introduced suitably.
- Incentive for ancillary (Up/Down) may be properly defined. In principle, only VC (& not FC) may be marked up. The appropriate commission may decide the mark-up quantum.
- Ancillary despatch should not create any perverse incentive towards inaction by players.
- Pool design (zero balance vs positive balance) to be suitably deliberated.
- Reserve Up & Down (RRAS) instruction could be issued by system operator (SO) from Generator to pool & vice versa.
- It would be a regulatory dispatch instruction from SLDC & additional contract need not be created in this process. SLDC can execute a contract rather than causing one.
- The suo-moto rescheduling provision of grid code could be suitably used when the default by an entity gets established.
- The model regulation need to leave ample room for SERCs to factor state-specific issues.

It was decided that a revised draft would be shared by SLDC Gujarat team after incorporating inputs from all the members.

8. Decisions taken for future work:

The following action plan was decided for the ensuing month:

- Feedback to FOR Technical Committee on the progress made by the sub-group.
- Tutorial on Optimization using GAMS at Delhi tentatively during 12-14 September 2019
- Next meeting of sub-group at Bangalore

9. Schedule for Next Meeting

It was decided that the 5th meeting would be help in September / October 2019 in southern region.

10. Member convener thanked Chairman, all members of the sub-group and other participants for their contribution in the meeting. The meeting ended with a vote of thanks to SLDC Maharashtra team.

5th meeting -31 Oct 2019, SRLDC Bengaluru

1. The fifth meeting of the sub-group on ‘Reserves and Ancillary Services at State Level’ was held at SRLDC Bengaluru on 31st October 2019 under the Chairmanship of Shri S. K Soonee, Advisor, and POSOCO. SLDC Madhya Pradesh, SLDC Gujarat, SLDC Maharashtra, Telangana and WRLDC Mumbai were connected through video conference.
2. Executive Director (SRLDC) welcomed all the members of the FOR sub-group and other participants to the meeting.

3. Member convener thanked SRLDC for hosting the meeting. He welcomed representative from SLDC Karnataka as a special invitee.
   Chairperson acknowledged the active interest & participation of SERC members / staff and the heads of SLDCs in various sub-group meetings.
4. **Confirmation of the minutes of the 4th meeting**: The minutes of the third meeting held on 30.08.2019 were confirmed by all members.
5. **SLDC Karnataka** gave a brief presentation on challenges faced by the state and the need for reserve ancillary services. A copy of his presentation is attached as **Annexure-II**. Key highlights are given under:
   a. Total Renewable generation Capacity in Karnataka is 13900 MW out of which Solar, 6448 MW (46%) is Solar, 4852 MW (35%) is Wind, 1731 MW (12%) is cogeneration and rest is biomass and mini hydro.
   b. Power supply for irrigation pump sets was being given during day time to utilize Solar generation
   c. This year Karnataka observed a maximum must run generation of 9000 MW (8000 MW from RE + 1000 MW from overflowing hydro) while the demand reduced to 6000 MW from a peak of 12000 MW. Under such conditions even after backing down ISGS generation to its technical minimum and closing down of intrastate thermal units, Karnataka had a surplus of around 4000 MW which was sold in the day-ahead market.
   d. 10x103.5 MW Sharavathy (Pelton wheel) and 4x115 MW Varahi (Pelton wheel) were being used as spinning reserves for handling load and RE variability
   e. Tail race hydro plants (Kadra-3x50MW, Kodsahally-3x40MW and STRP-4x60MW) were being dispatched during Non-solar peak period
   f. Development of pumped storage scheme is envisaged at Sharavathy and Varahi
   g. The development of real-time market would enable the States to dispose the surplus power.
   h. Deviation volume limit and must-run status for RE during high penetration could be reviewed
6. **Chief (Regulatory Affairs)**, CERC stated that
   a. The CERC, through its various orders and regulations had made it amply clear that the grid does not generate electricity. It cannot be considered as a source or sink of electricity. Hence raising the deviation limit militates against the basic principle of maintaining load-generation balance.
   b. CERC passed an order in 2015 charting out roadmap for reserves including primary, secondary and tertiary reserves requirement for system reliability. Subsequently the Commission mandated primary response by directing RLDCs to restrict the schedules to

Maximum Continuous rating of the units at bar minus the normative auxiliary consumption.

c. Pilot project for Secondary control (Automatic Generation Control) were initiated through the CERC roadmap for reserves. He also updated about the recent Order by the Hon’ble CERC regarding AGC enablement being mandatory for Inter-State Generators.
d. Tertiary control through reserve regulation ancillary services (RRAS) & fast response ancillary services (FRAS) mechanisms in administered mode have been implemented at regional level
e. Co-optimizated dispatch of energy and reserves with market based approach is required.
f. Complementary initiatives for development of real-time market are being taken up. A staff paper on real time market (RTM) was floated followed by draft amendments to relevant Regulations to roll out RTM.
g. The expectation from sub-group is to evolve a common minimum framework for assessment, procurement, despatch and settlement of reserves for implementation at the intrastate level.
h. The sub-group is expected to evolve model regulations for enabling assured availability of mandated quantum of reserves and its deployment under contingencies. The model regulations could be suitably adapted by respective SERCs to suit the requirements of the respective states.

7. The draft report of the sub-group (**Annexure-III**)was deliberated in detail the following suggestions made by the sub-group members were agreed for inclusion in the draft report:

a. Primary response has to be mandated through the grid code. The upper and lower bounds for scheduling are to be mandated through the regulations for ensuring availability of adequate margins in a distributed manner across all intrastate generating stations.
b. Implementation of SAMAST framework is required to enable implementation of robust scheduling, metering, accounting and settlement of transactions in electricity.
c. SAMAST implementation inter alia includes implementation of intrastate ABT. The system would bring in transparency, accountability and discipline on the part of the generating stations as well as its procurers.
d. SERCs to notify the technical minimum limit of 55% and ramp rates (of at least 1 % per min) in line with the CERC norms for thermal generation to enable computation and monitoring of reserves in real-time.
e. SERC to mandate submission of various details for participating in ancillary services (Fixed charges, Energy charge rate, minimum turn down level, minimum operating hours after bring the unit on bar, shut down/start up cost etc.)

f. The members also agreed that the transition towards market-based procurement of reserves and ancillary services could be in a phased manner.
g. The assessment of reserve could be estimated as thrice of the standard deviation of the historical area control area.
h. Reserve assessment could be done on a rolling window of seven days. In case of inadequacy of available reserves additional units to be brought on bar. In case of surplus availability of reserves, the decision for taking one or more units under reserve shutdown to be taken.
i. A schematic to explain the MCR, DC, Scheduling limits, spinning reserve, primary reserve, ramping reserve (up/down) etc. to be included in the report
j. The criteria for triggering the ancillary services could be included in the regulations
k. The stacking of reserves shall be as per their energy charge rate.
l. The ancillary service providers to be compensated for flexibility services
m. Mechanism for reserve monitoring in different time horizons
n. The scheduling and settlement of ancillary dispatch to be 15minute to start with. A faster dispatch interval of say 5 minutes could be considered in future.
o. Gate closure is required, to enable the SLDCs to assess the available reserves at the State level with certainty, ahead of the delivery time. The time line to be aligned with the gate closure and real-time market at the interstate level
p. A virtual ancillary entity shall be created to enable reserve despatch to/from the pool. Only energy charges plus mark up to be paid for the reserves despatched by the SLDC. Suggested mark-up is 10 to 25 paise/unit.
q. The ancillary dispatch received by a generating station shall be subsumed in the injection schedule and the deviation from schedule would be computed with reference to the total schedule including the ancillary despatch.
r. Secondary control through Automatic Generation Control could be implemented in few of the larger States.
s. Robust communication system with path redundancy needs to be established between the SLDC and the generating stations as well as between the SLDC-RLDC-NLDC for fast and reliable exchange of exchange of scheduling data.
t. Other essential reliability services viz. voltage control ancillary service and black start ancillary service etc. shall be suitably incorporated in the report considering the present scope & future requirements.
u. A road map for implementation starting with publication of draft regulations on intrastate reserves and ancillary by respective SERC within 1 year shall be devised

8. Following **decisions** were also taken in the meeting:

a. The revised draft report shall be compiled and recirculated to the sub-group members for the review and comments
b. The draft model regulations and the implementation roadmap shall be redrafted and circulated for review
c. The revised draft report of the sub-group shall be presented in the next FOLD meeting for wider consultation with the SLDCs
d. The 6th meeting of the sub-group could be scheduled in Delhi in the last week of November 2019 for finalization of the report for presentation in the next FOR standing technical committee meeting

9. The Chairman thanked all the members for their valuable contributions.
10. Member convener thanked the Chair.

Annex-III: Summary of the Capacity building program

As decided in the 4th meeting of the FOR technical committee sub-group on intra-state reserves & ancillary services, a capacity building programme on Implementation of *'Optimization Techniques for Indian Power System Operation'* was conducted at NLDC New Delhi on 19-21 Sep 2019 in collaboration of NLDC & IIT Delhi. The programme was attended by senior officials as well as working groups on optimisation from different SLDCs, NLDC, RLDCs including Chairman of the FOR subgroup, the member convenor (Advisor (RE), CERC, Director (SO) POSOCO, Chief Engineer (SLDC) Gujarat. Key highlights of the programme are as given under:

Day-1 (19-Sep-2019):

1. **Session-1: Introduction to Optimization**:
   - Optimization problem formulation;
   - Different types of optimization problems (LP, NLP, MILP, MINLP)
   - Objective Function,
   - Equality & Inequality Constraints
   - Decision Variables, Dual variables (Lagrange multipliers)
   - Popular Optimization packages viz. GAMS (General Algebraic Modeling System, AMPL (A mathematical Programming Language), MATLAB tool box etc.
   - History & Evolution of Optimisation techniques
   - Classification of Optimisation Problemsbased on constraints, nature of variables, nature of equations, objective type etc.
2. **Session-2: Introduction to Excel as Optimization Solver EXCEL**
   - Illustrations with sample examples
   - Interpretation of Excel solver output & typical terms viz. sensitivity report, Answer report, allowable increase/decrease, shadow price, binding & non-binding constraints etc.

3. **Session-3: Economic Load Despatch (ELD)**
    - Introduction to economic load dispatch
    - Problem formulation
    - Solution by Method of Lagrange Function
    - Solution Techniques
    - ELD with network losses
    - Examples
    - ELD when unit limits are considered

Day-2 (20-Sep-2019)

4. **Session-4: Unit Commitment Problem**
    - Introduction to Unit Commitment
    - ELD & Unit Commitment
    - Issues
    - Problem formulation
    - Examples
5. **Session-5: Introduction to General Algebraic Modelling System (GAMS)**
    - Introduction – What is GAMS,
    - Types of problems solved by GAMS
    - The basic components of GAMS model
    - Algebraic Representation
    - Mathematical Modelling
    - Structure of a GAMS model – Sets, List, Table, Scalar, Assignment, Variables, bounds, equations, model statements, solve statements, Conditional Operators, logical operators, data transfer tools etc.
    - GAMS Solvers viz. CPLEX
    - Sample Example – Transportation problem
6. **Session-6: Hands on Session on GAMS**
    - Writing & running GAMS code
    - Error detection
    - Interpretation of GAMs output (.lst) file
    - Solving the ELD & UC problems of Day-1 & Day-2 using GAMs
    - Comparing GAMS solution with Excel Solver solution in Unit Commitment case – limitations of excel solver in changing unit status from 0 to 1 leading to suboptimal solution

Day-3 (21-Sep-2019)

7. **Session-7: Orientation programme on SCED Module being operated at NLDC**
8. **Session-8: Learning & Feedback:**

Key Learnings from the program:

(1) Basics of optimization, ELD, UC and GAMS
(2) Solving Optimization problems through MS Excel solver, GAMS Modelling Tool and MS Excel limitations
(3) Handling of glitches, implementation complexities and modelling strategies for state specific optimization formulation
(4) Sharing of Practical Implementation experience by NLDC for optimization and Roadmap for implementation of SCED
(5) Requirements and Key design elements required in the Regulatory framework for initiating optimization at intra-state level.

Suggestions for Future Programs/Tutorials

(1) Formulation of Optimization Problems to incorporate near term challenges such as Renewables
(2) Interfacing requirements with EMS and State Estimation
(3) Metrics for Performance Monitoring
(4) Specifications for the IT infrastructure and Overview of development of Web based Software and User Interface
(5) Financial Accounting and Settlement for Economic Despatch and Pool Accounts
(6) Need for closer to real life problem solving and case studies

Interfacing of MS Excel, Python, MATLAB, PSSE or any other software with the GAMS Modelling tool for optimization

9. **Deliberation of Future Action Points by the sub-group**: Further, the following points were discussed on 20-Sep-2019 in presence of the teams from SLDC Madhya Pradesh, SLDC, Gujarat, SLDC Maharashtra, WRLDC & NLDC so as to decide future course of action by the FOR sub-group.

(1) A draft outline of the report was proposed & deliberated
(2) It was proposed that the report would have
   - a dedicated chapter on pilot projects at each of the 3 states viz. Madhya Pradesh, Gujarat, Maharashtra
   - A new chapter on steps/ roadmap for a new state to rollout ancillary services
   - Necessary intervention from regulatory commissions viz. regulations on technical minimum level, compensation for part load operation, ramp-rate declaration by generators etc.
   - Need for a pilot order for implementation of ancillary

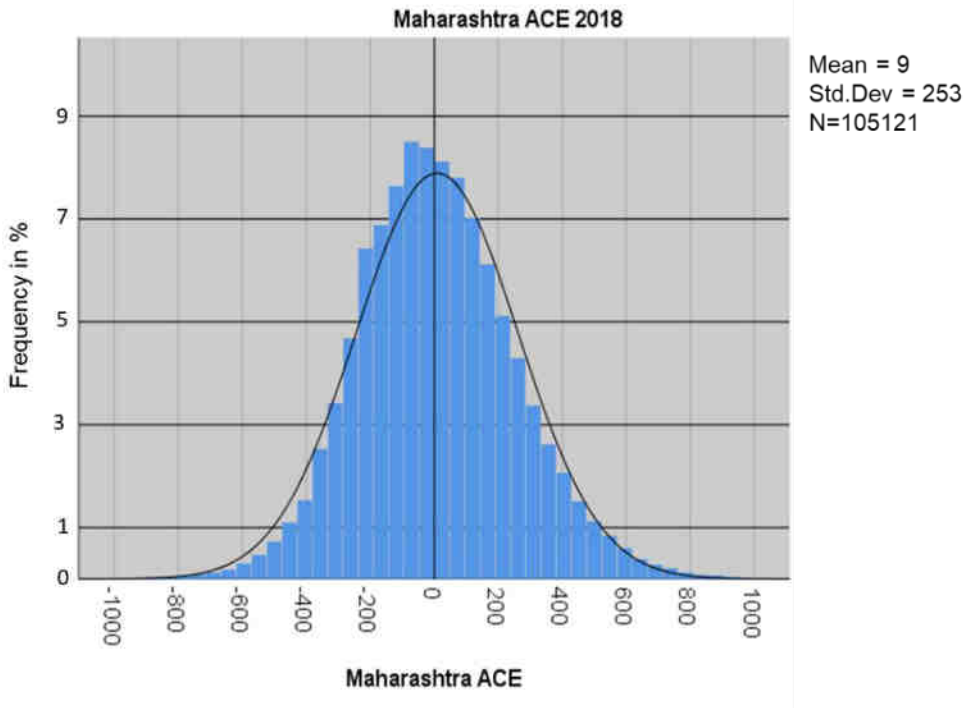
(3) The 3 SLDCs (GJ, MP, MH) who have extensively used excel solver for optimisation shall attempt to scale it up using GAMS software
(4) The report to mention & explain the need for an ERC order for pilot implementation & gradual improvement based on experience gained thereof
(5) NPTEL courses on optimisation provide a good learning opportunity
(6) SLDC Gujarat & Maharashtra teams expressed that they already have a system of economic load despatch in place and thus they would like to have a framework for assessment & despatch of reserves

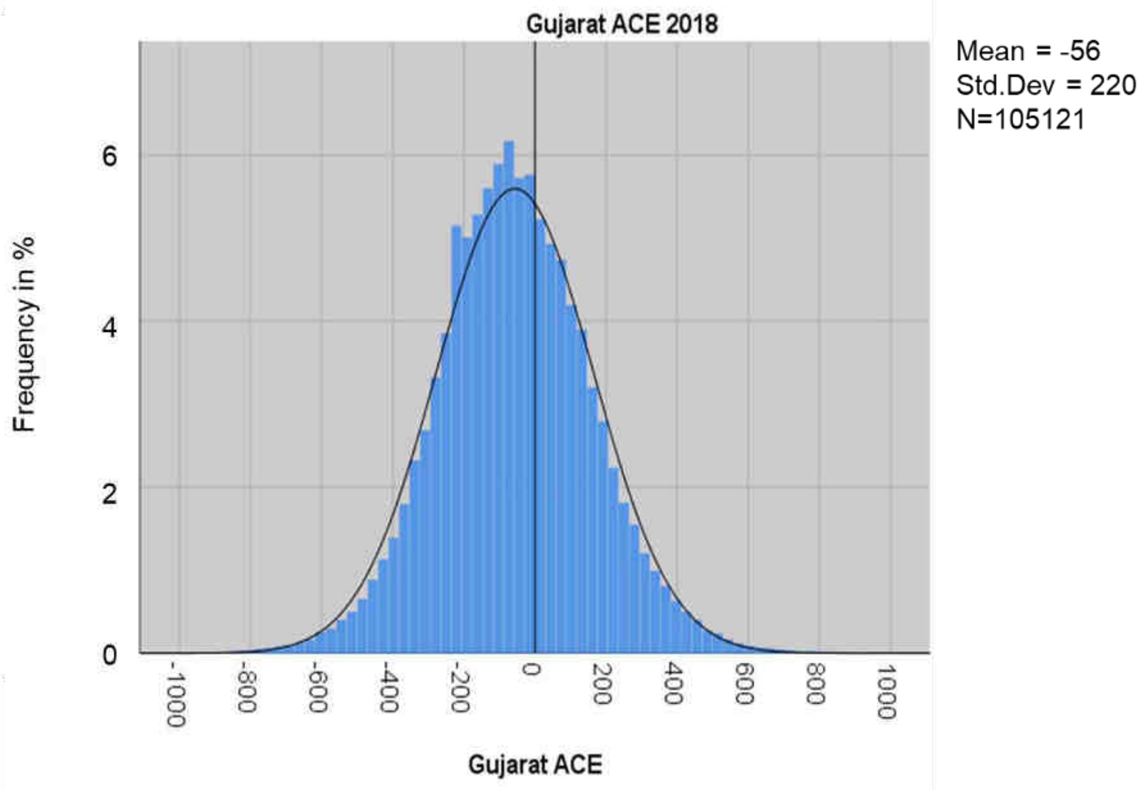
Annexure-1: List of Participants

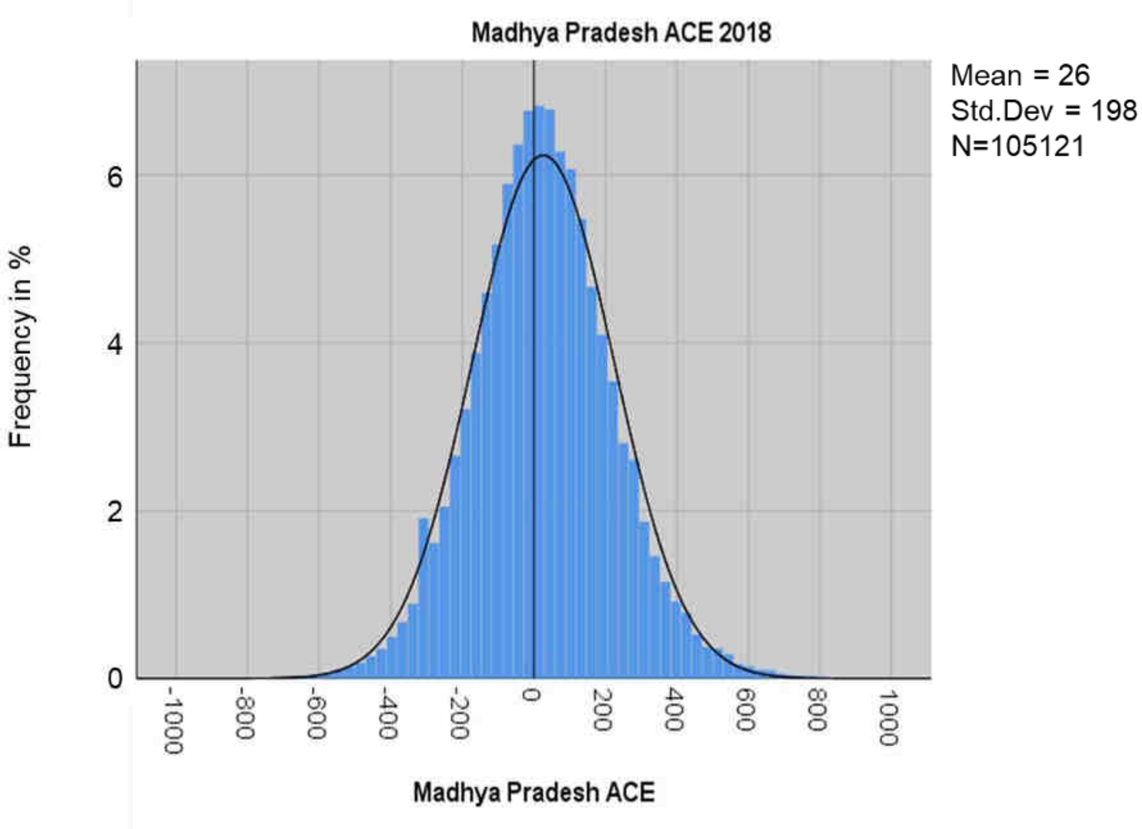
S.N.	Name	Designation	Organization
1	Prof. A R Abhyankar	Professor	IIT-Delhi
2	Dr. Shri Ram Vaishya	Post Doctoral Fellow	
3	Ms. Shruti Ranjan	Ph.D Student	
4	Ms. Megha Gupta	Ph.D Student	
5	Ms. Shaziya Rasheed	Ph.D Student	
6	Ms. Meenakshi Khandelwal	Ph.D Student	
7	Sh. Ambuj Gupta	M.Tech Student	
8	Sh. Ravi Kadam	Advisor	CERC
9	Sh. J D Trivedi	Dy. Engineer	SLDC - Gujarat
10	Sh. P B Suthar	Dy. Engineer	
11	Sh. A J Gami	Dy. Engineer	
12	Sh. B B Mehta	Chief Engineer	
13	Sh. Avinash C. Dhawade	DYEE (Operations)	SLDC-Maharashtra
14	Sh. Vijay S. Kamble	AE (Operations)	
15	Sh. Aarif Ahmad Khan	JE	SLDC-Madhya Pradesh
16	Sh. V.K Agrawal	EE	
17	Sh. Rishabh Nayak	AE	
18	Sh. L Sarveshwar	AE	SLDC-Telangana
19	Sh. Naveen	AE	
20	Sh. Chandan Mallick	Dy. Manager	ERLDC
21	Ms. Sugata Bhattacharya	Executive Trainee	
22	Sh. MP Nath	Chief Manager	NERLDC
23	Sh. Rohit Tulasiyan	Executive Trainee	NRLDC
24	Sh. Ashutosh Kr Pandey	AM	
25	Sh. Ankit Gupta	DM	
26	Sh. Bheemesh	JE	SRLDC
27	Sh. Vivek Pandey	Sr. DGM	WRLDC
28	Sh. Aditya Prasad Das	DGM	

Annexure-1: List of Participants			
S.N.	**Name**	**Designation**	**Organization**
29	Sh. Naga Sudhir	Dy. Manager	
30	Sh. S.R.Narasimhan	Director (SO), POSOCO	NLDC
31	Sh. S.K. Soonee	Advisor	
32	Sh. Debasis De	ED	
33	Sh. Phanishankar	Dy. Manager	
34	Sh. Saif Rehman	Dy. Managaer	
35	Sh. Harish Rathour	DGM	
36	Sh. Mohneesh Rastogi	Manager	
37	Sh. S C Saxena	GM	
38	Sh. K.V.N Pawan Kumar	Manager	
39	Sh. Anupam kumar	Manager	
40	Sh. Shubham Verma	ET	
41	Sh. Laxman Singh	ET	
42	Ms. Anamika Sharma	CM	
43	Sh. Sharat Chandra	Manager	
44	Sh. Anuj Kumar	AM	
45	Sh. Sudheer Talluri	Manager	
46	Sh. N. Nallarasan	Sr. DGM	

Annex-IV: Area Control Error: Frequency distribution






Madhya Pradesh ACE 2018
Mean = 26
Std.Dev = 198
N=105121
Frequency in %
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2
0
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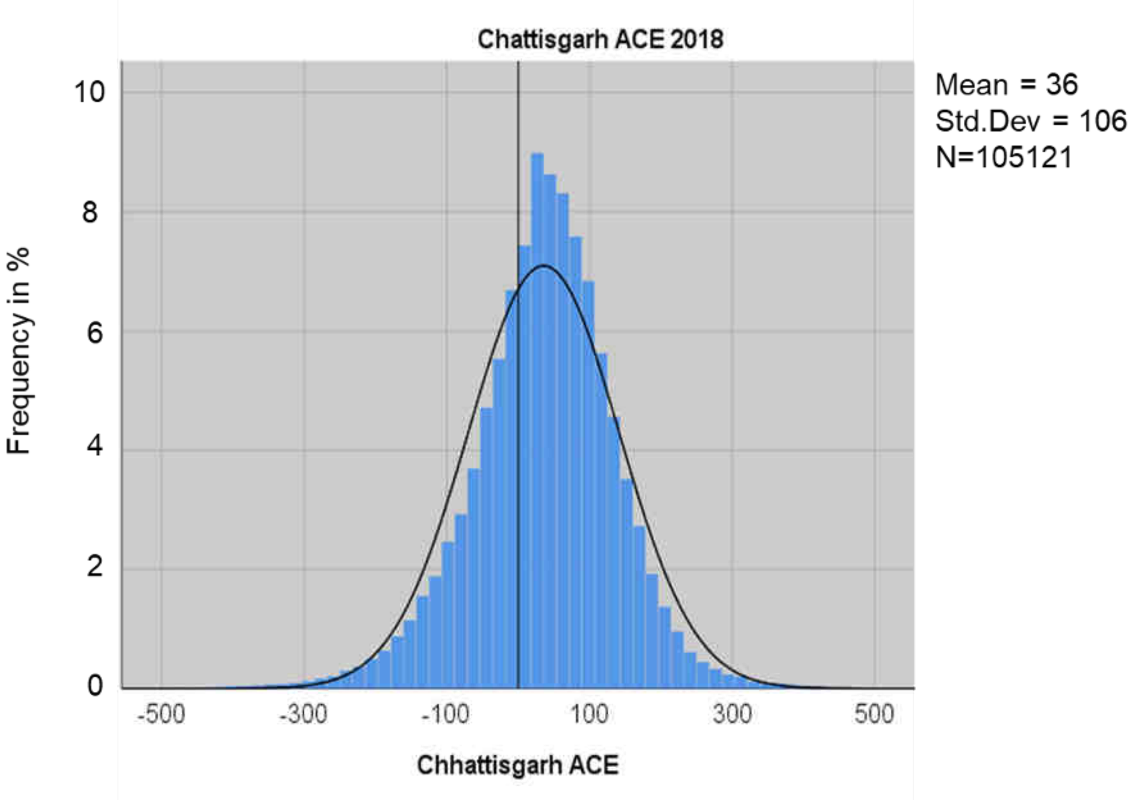
-800
-600
-400
-200
0
200
400
600
800
1000
Madhya Pradesh ACE


Chattisgarh ACE 2018
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Std.Dev = 106
N=105121
Frequency in %
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2
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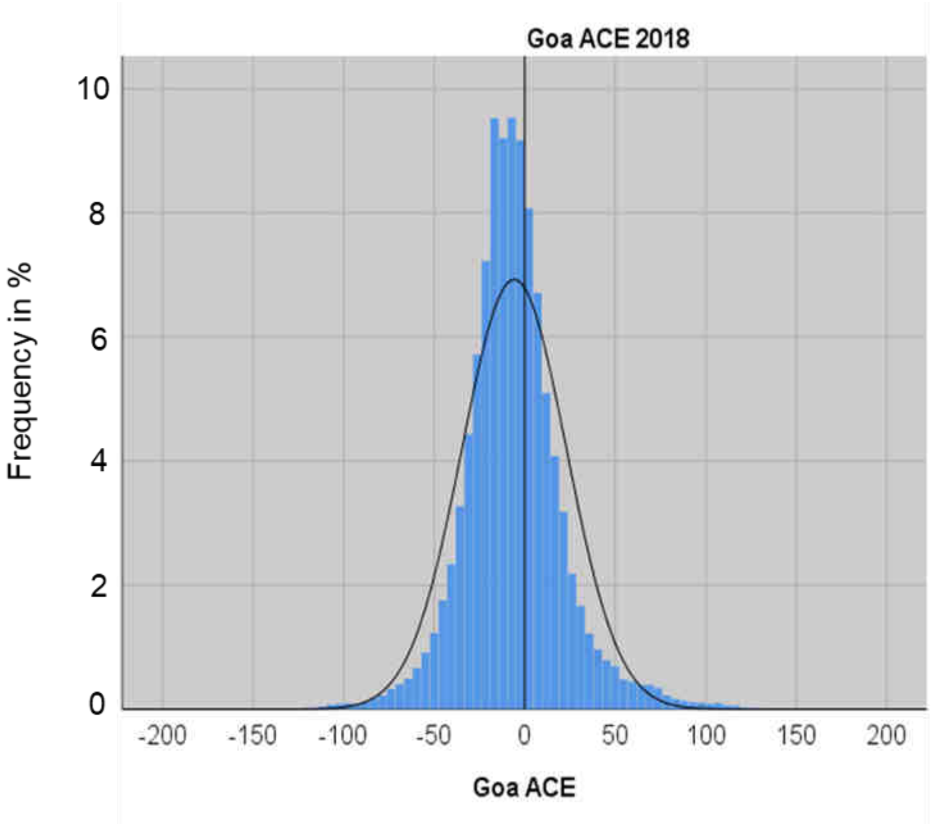
-100
100
300
500
Chhattisgarh ACE



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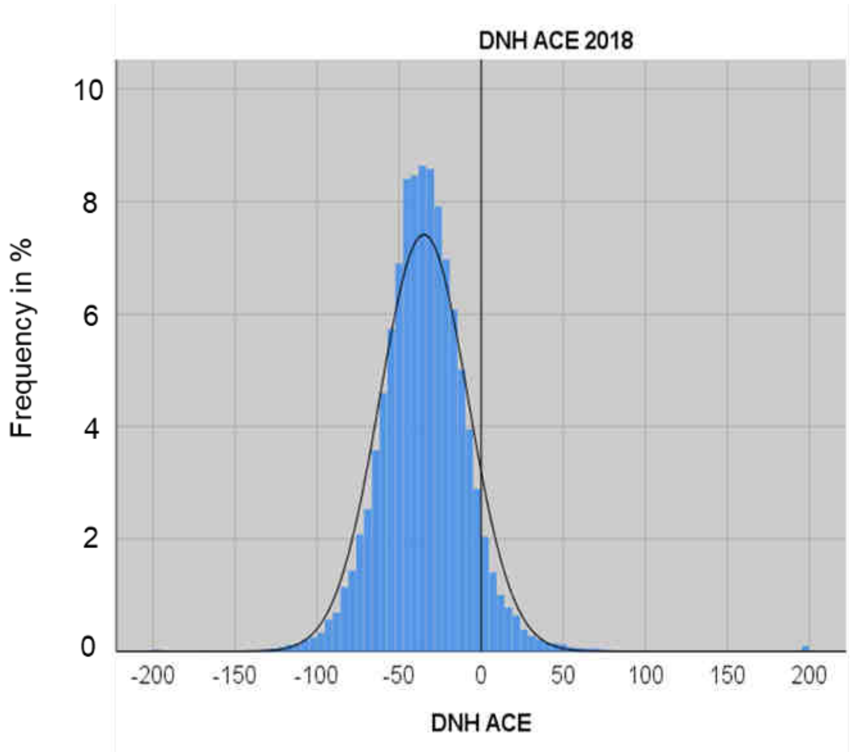

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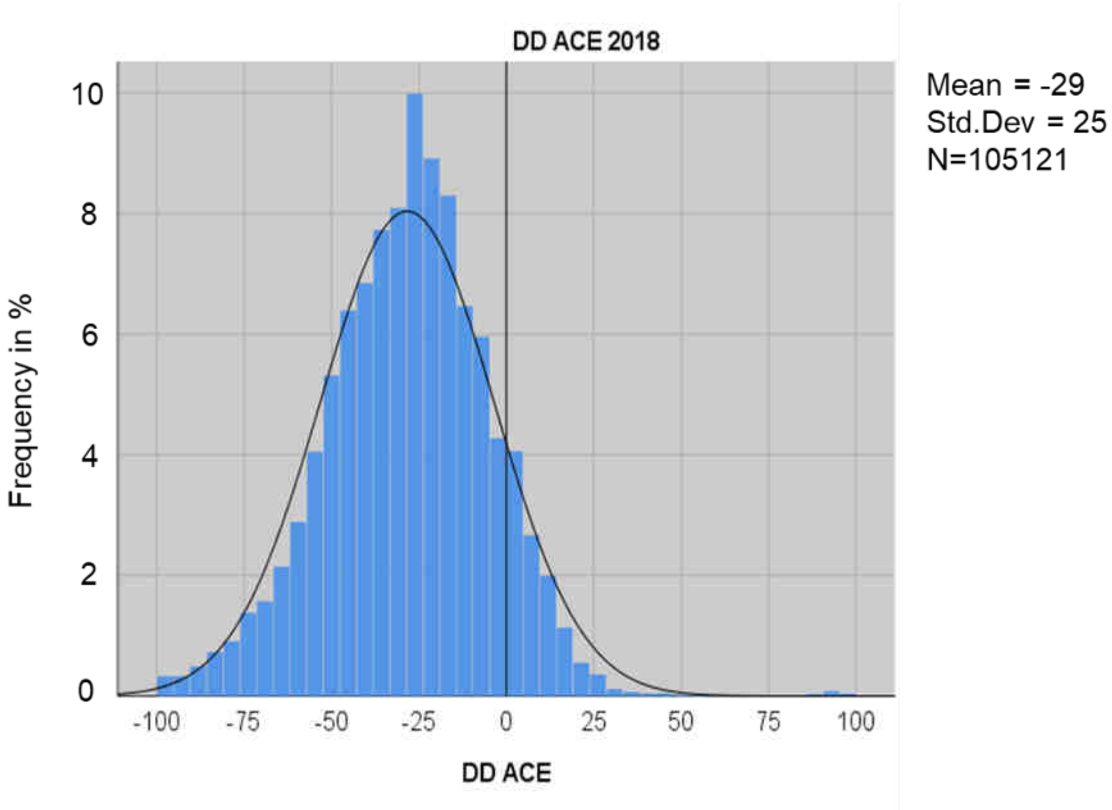
DD ACE 2018
Frequency in %
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0
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50
75
100
DD ACE
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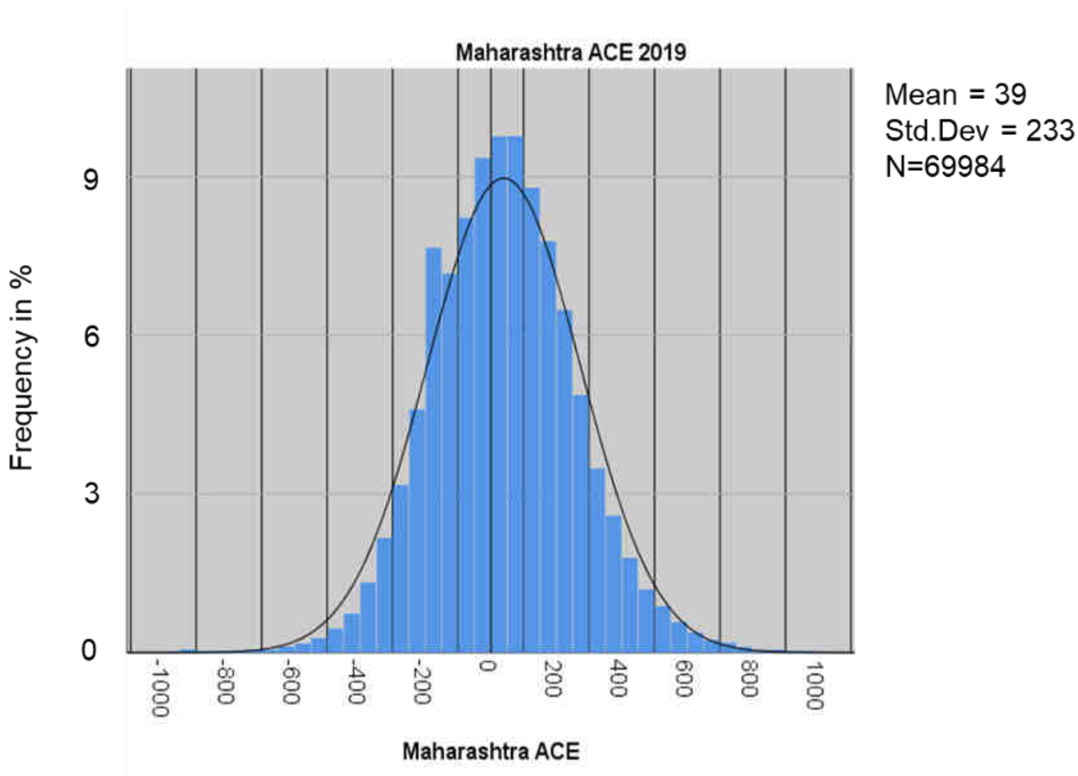
Std.Dev = 25
N=105121


Maharashtra ACE 2019
Frequency in %
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6
3
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-1000
-800
-600
-400
-200
0
200
400
600
800
1000
Maharashtra ACE
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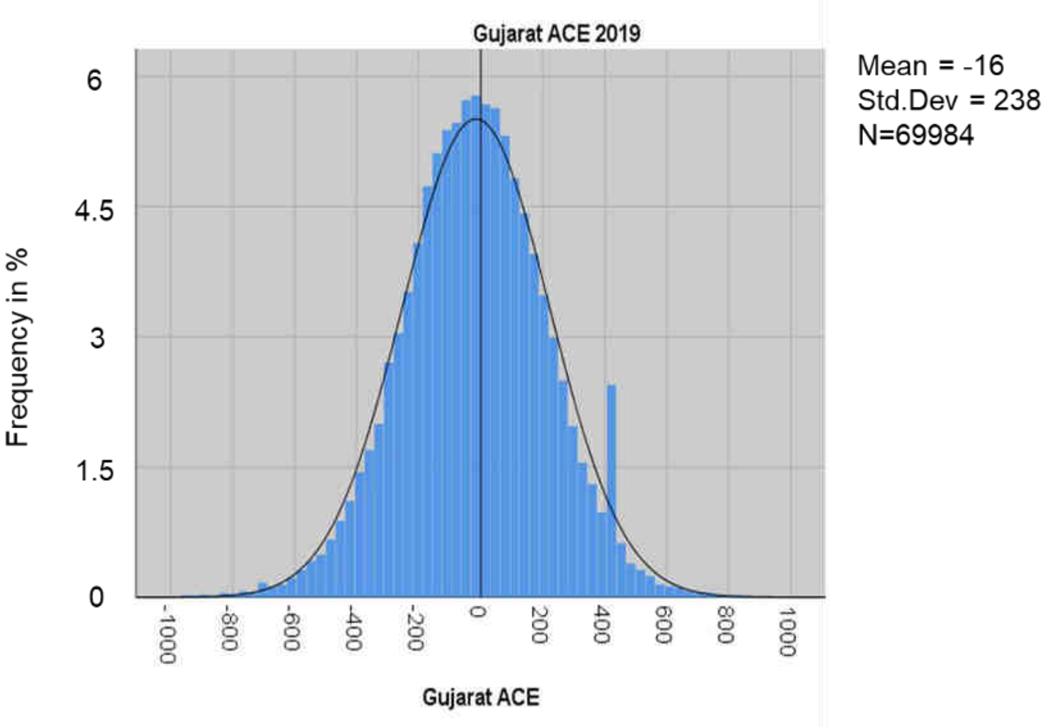
Std.Dev = 233
N=69984



Gujarat ACE 2019
Mean = -16
Std.Dev = 238
N=69984
Frequency in %
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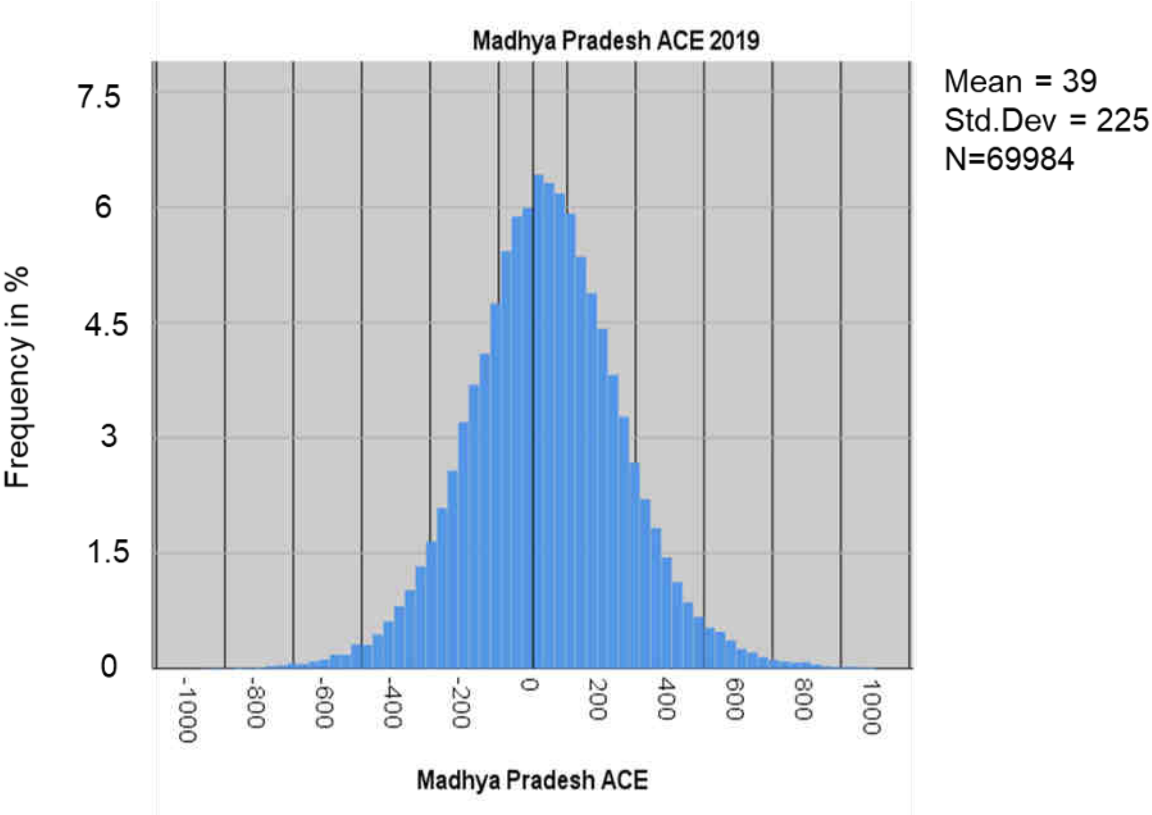
-400
-200
0
200
400
600
800
1000
Gujarat ACE



Madhya Pradesh ACE 2019
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Std.Dev = 225
N=69984
Frequency in %
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4.5
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1.5
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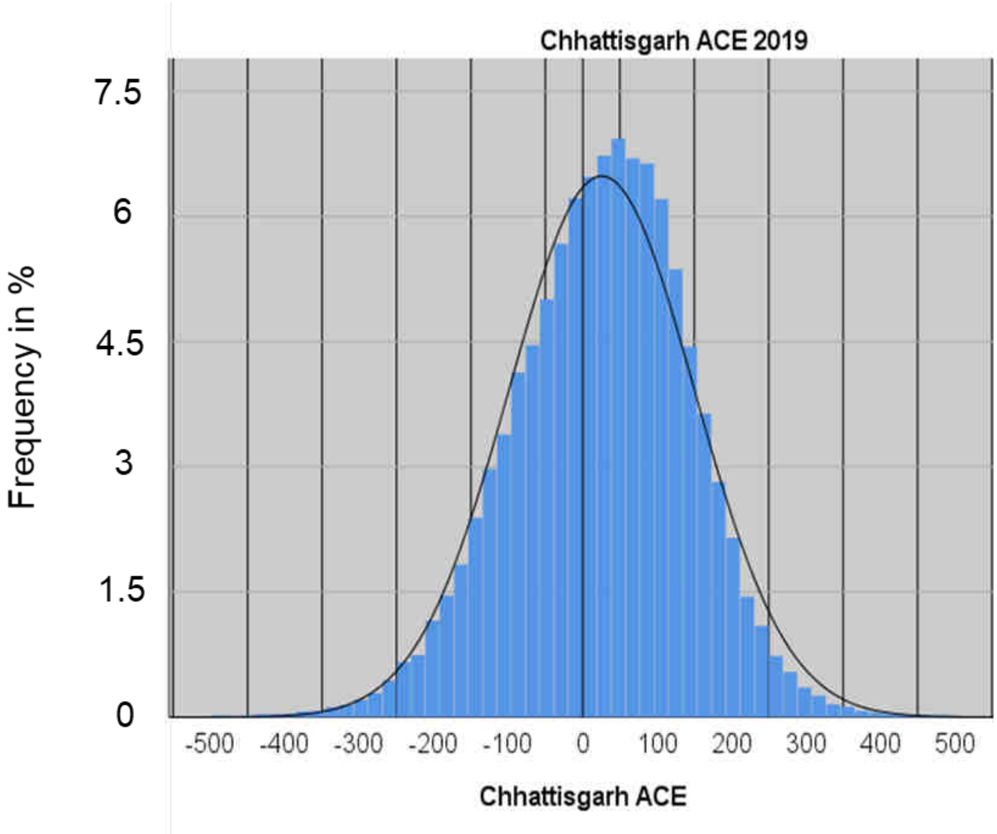
-800
-600
-400
-200
0
200
400
600
800
1000
Madhya Pradesh ACE



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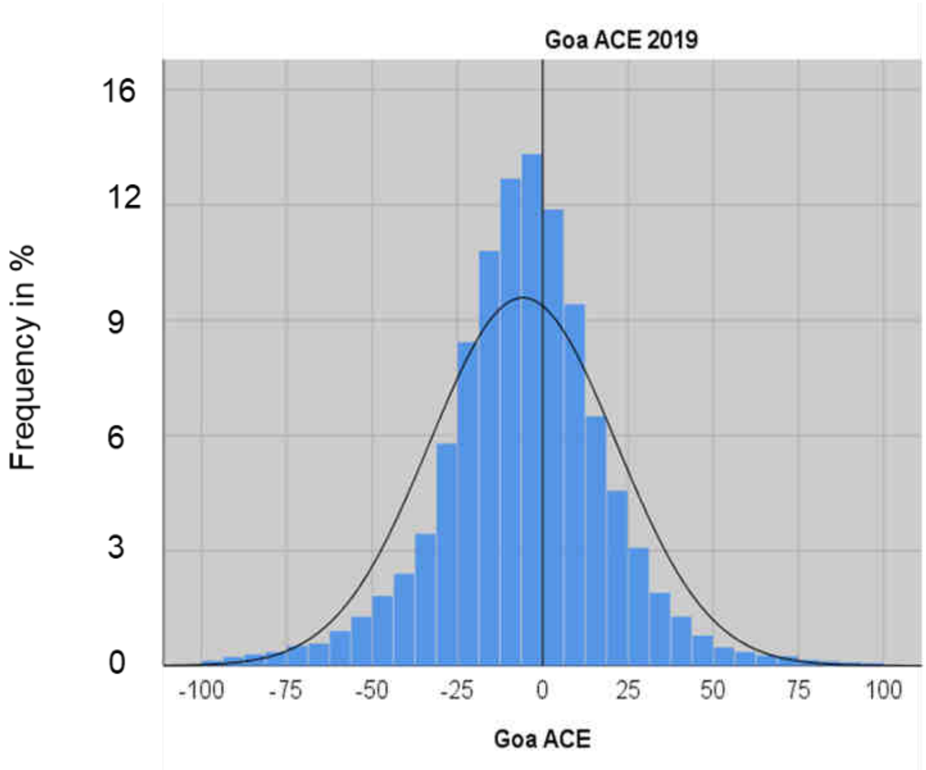
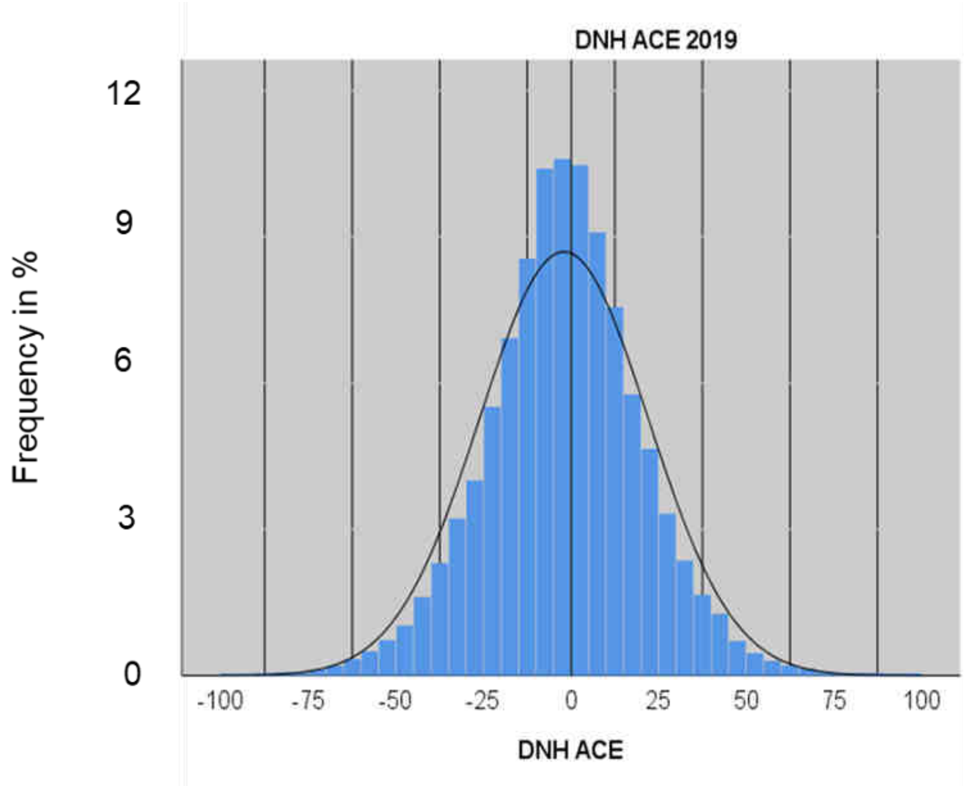
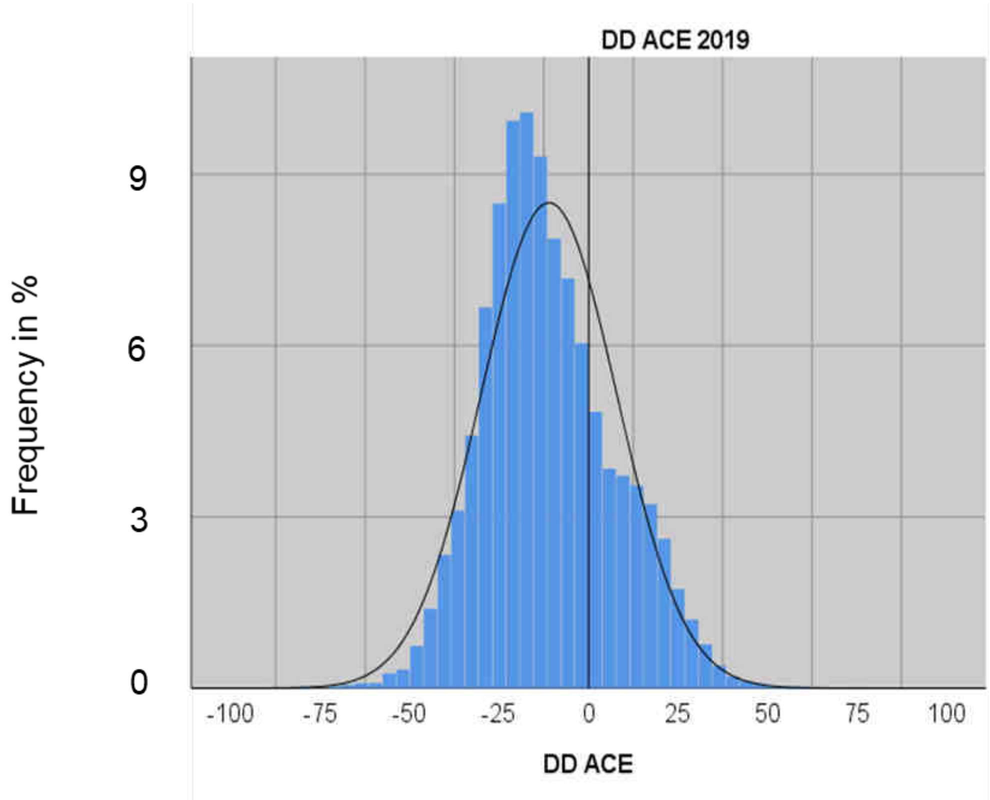
Std.Dev = 124
N=69984



Mean = -6
Std.Dev = 27
N=69984

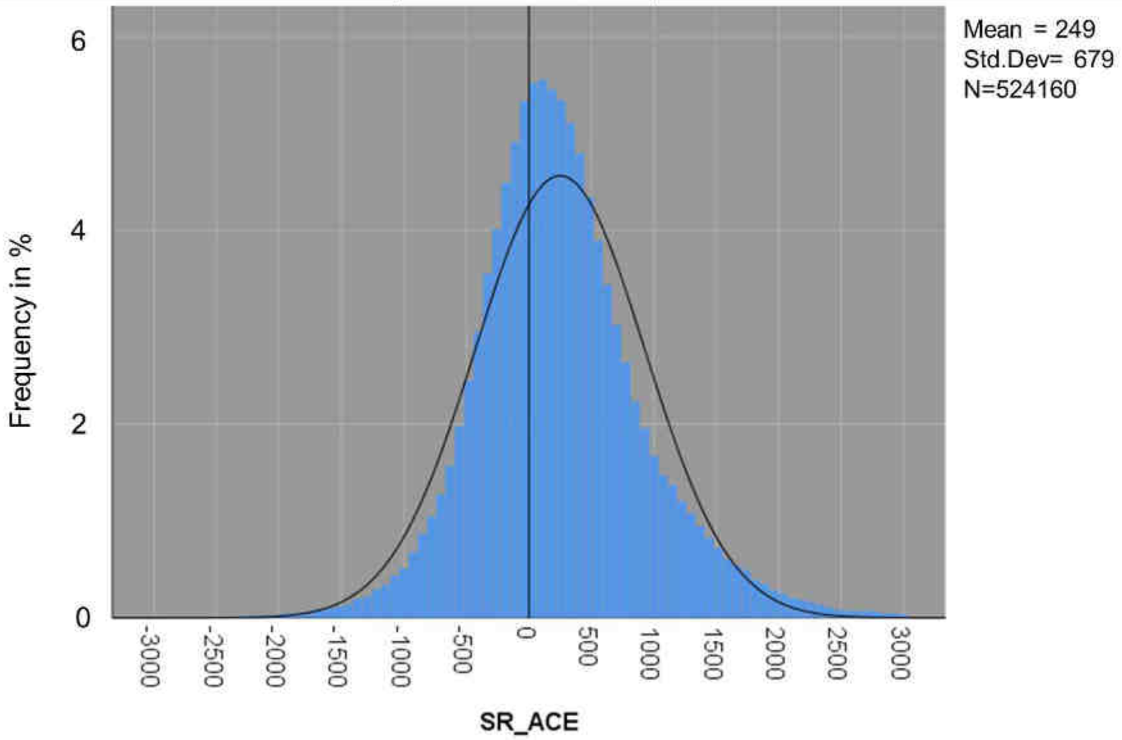


Mean = -2
Std.Dev = 24
N=69984

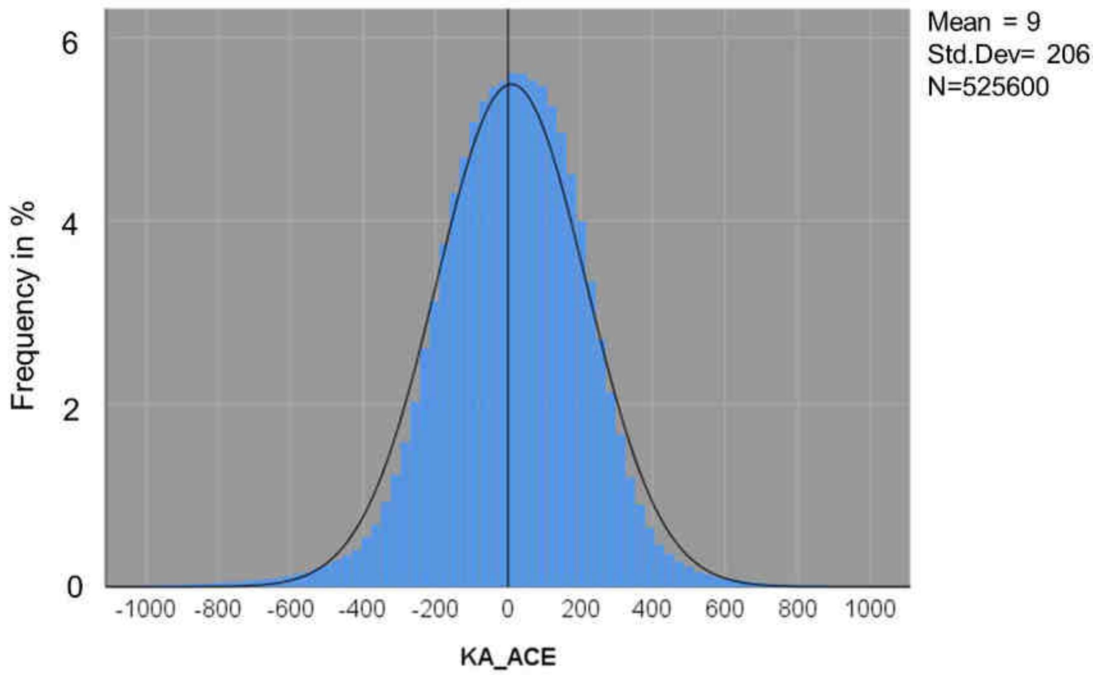


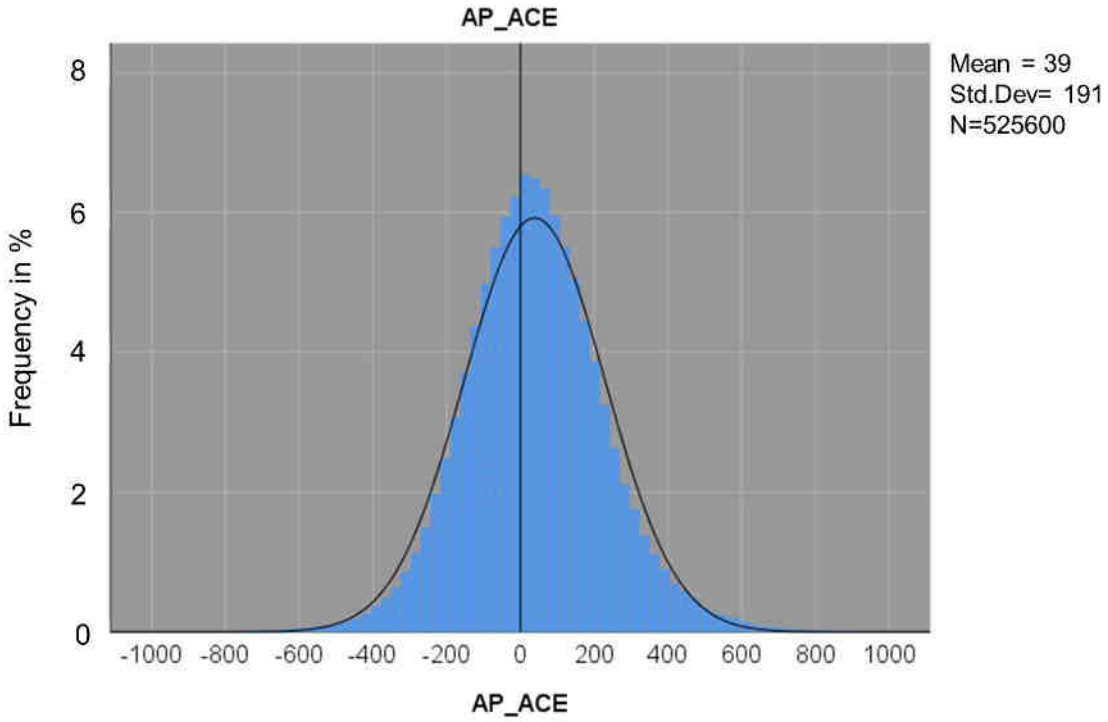
Mean = -11
Std.Dev = 19
N=69984

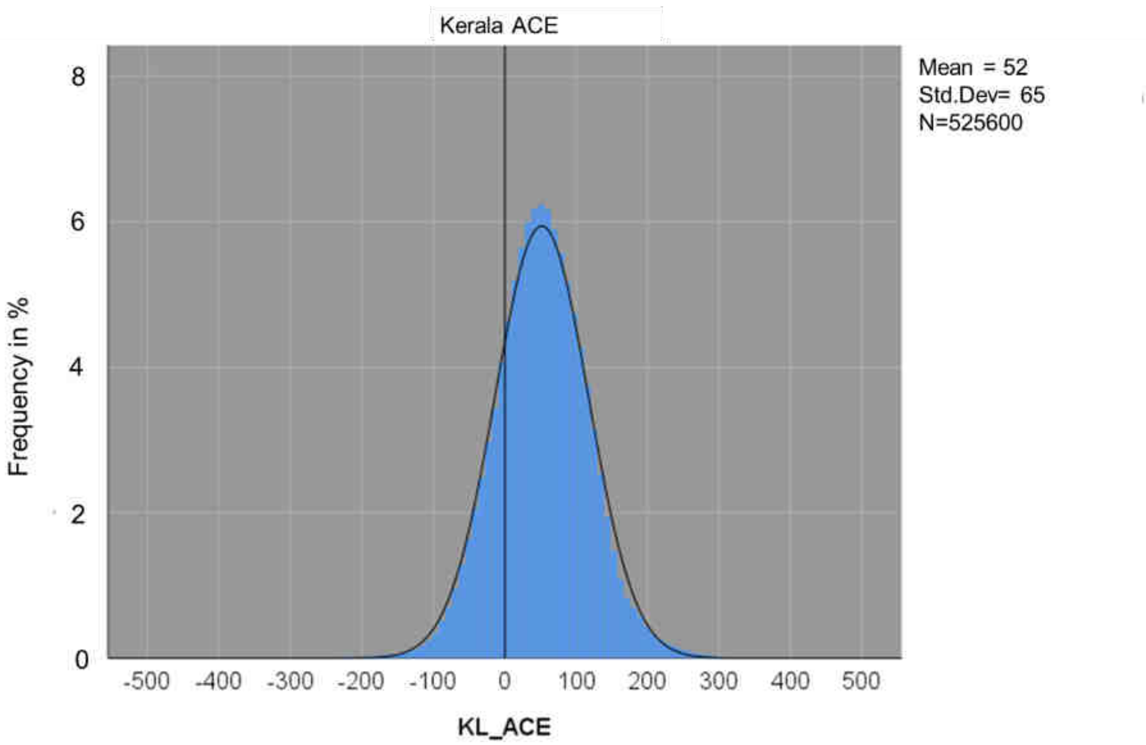
SR ACE

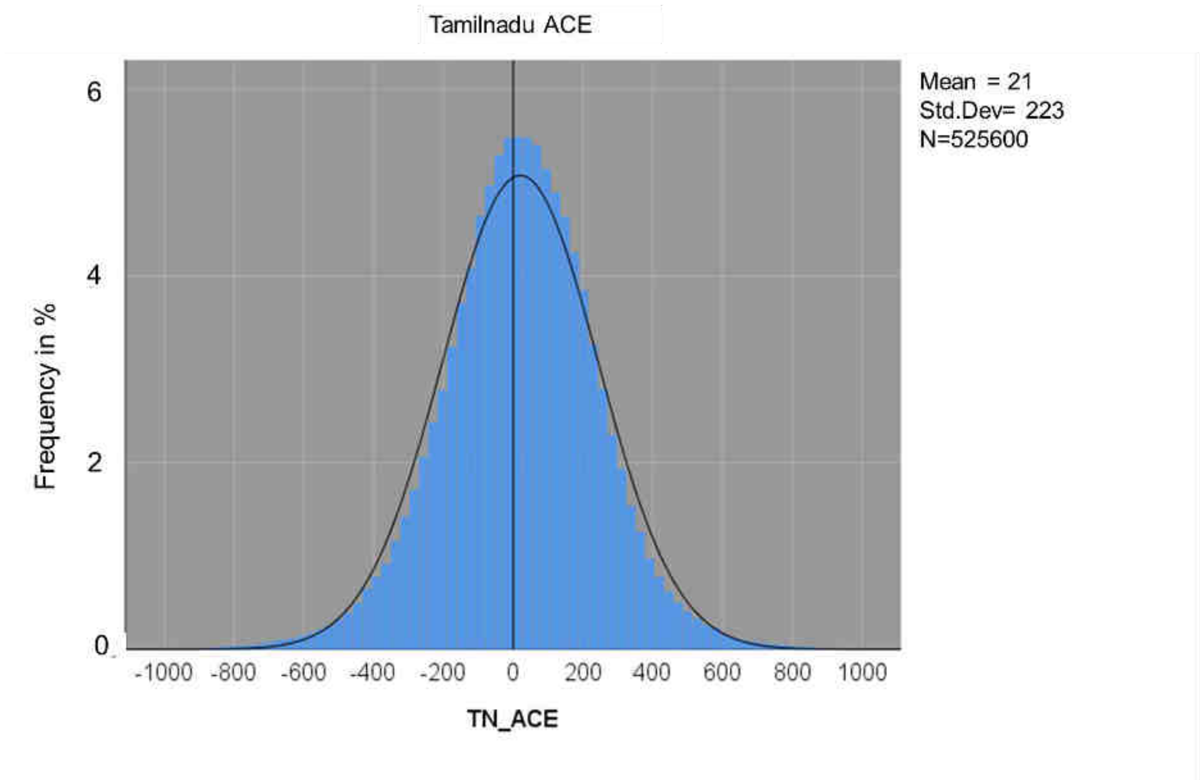


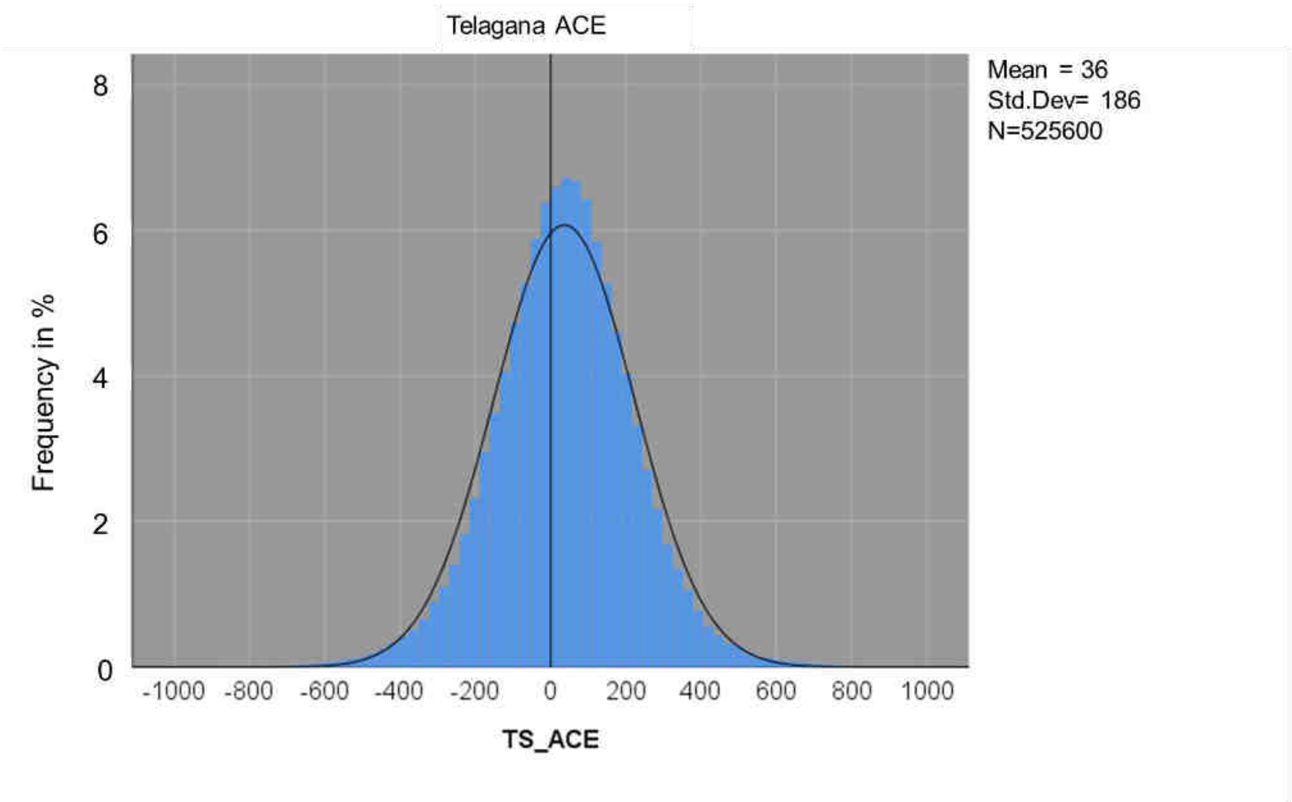
Karnataka ACE

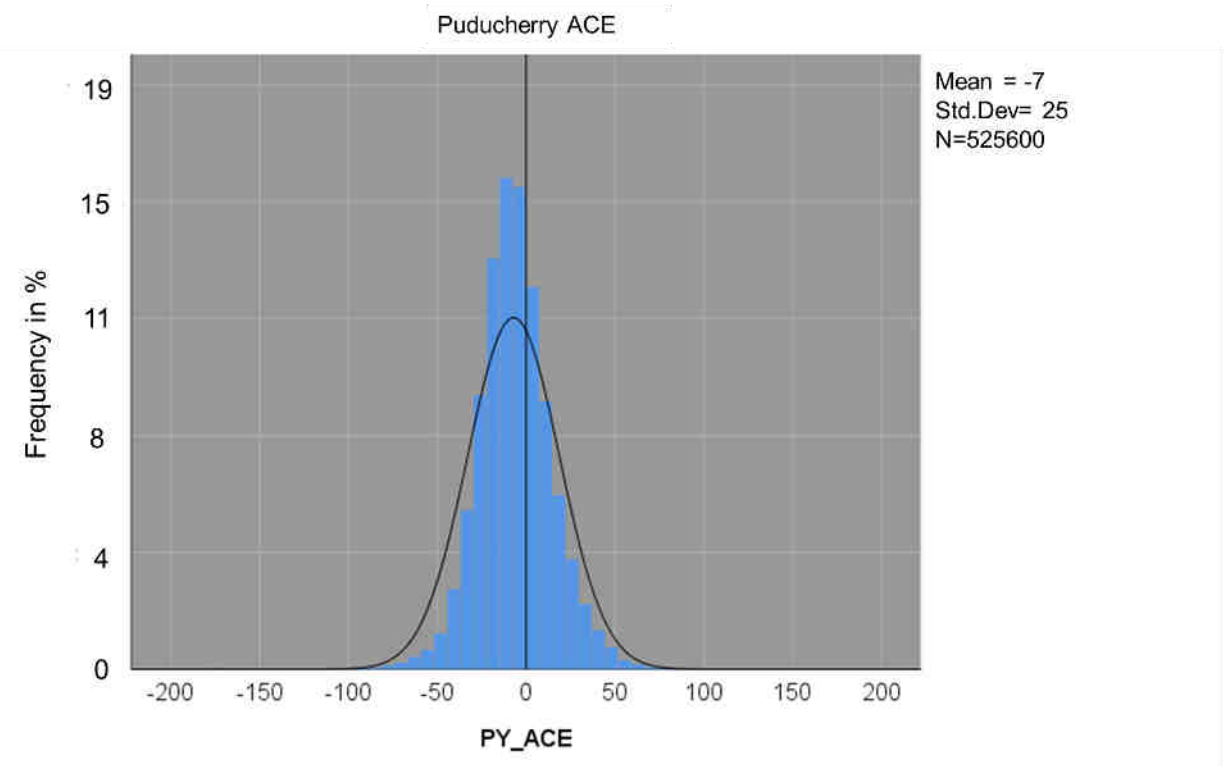



AP_ACE
Mean = 39
Std.Dev= 191
N=525600
Frequency in %
8
6
4
2
0
-1000
-800
-600
-400
-200
0
200
400
600
800
1000
AP_ACE

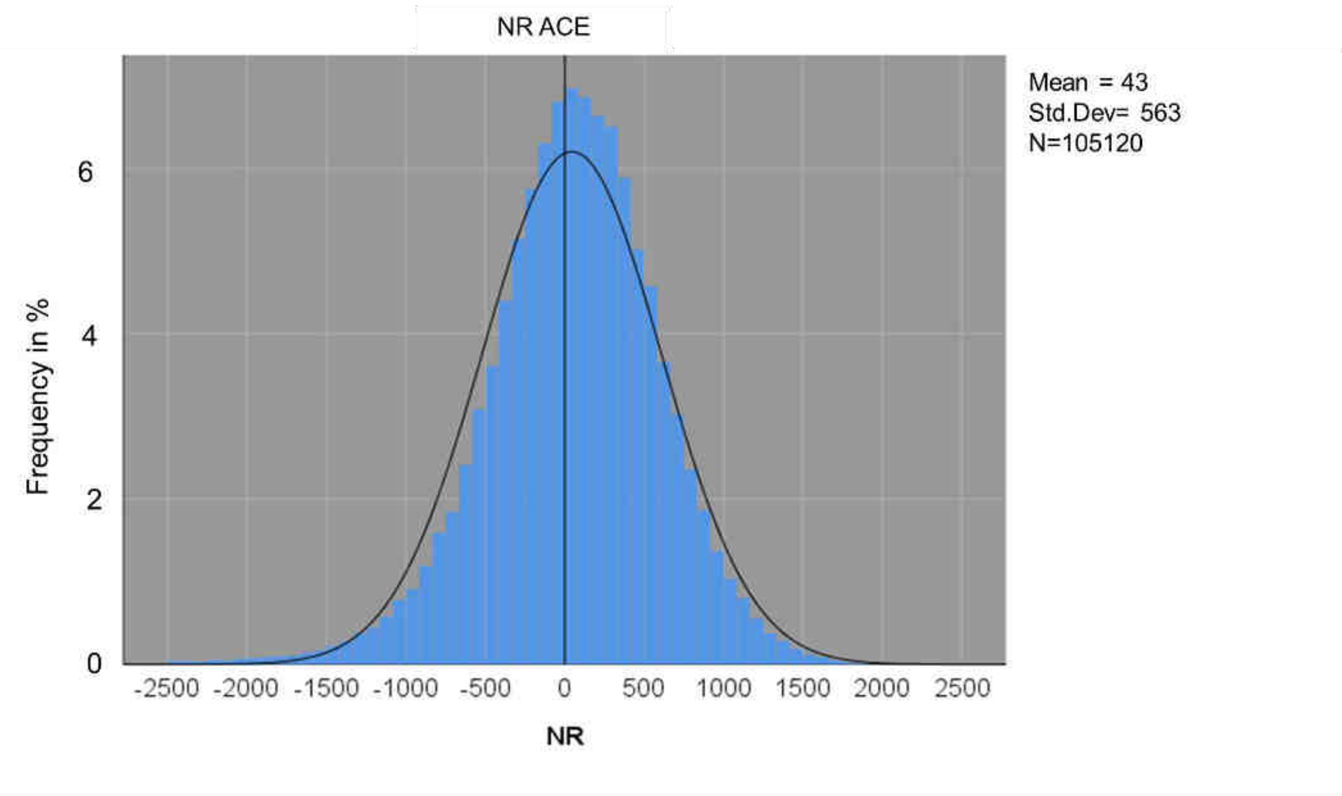

Kerala ACE
Mean = 52
Std.Dev= 65
N=525600
Frequency in %
8
6
4
2
0
-500
-400
-300
-200
-100
0
100
200
300
400
500
KL_ACE


Tamilnadu ACE
Mean = 21
Std.Dev= 223
N=525600
Frequency in %
TN_ACE

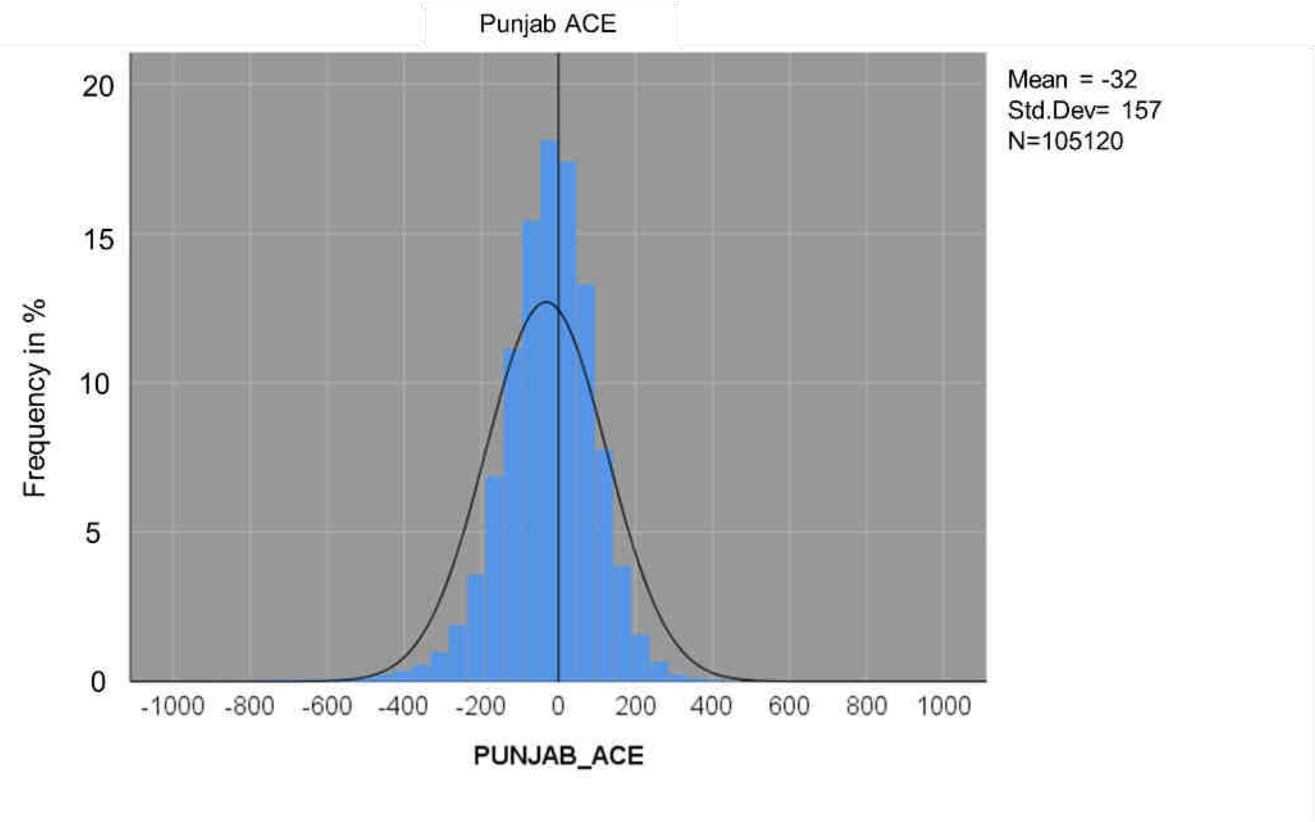

Telagana ACE
Mean = 36
Std.Dev= 186
N=525600
Frequency in %
TS_ACE

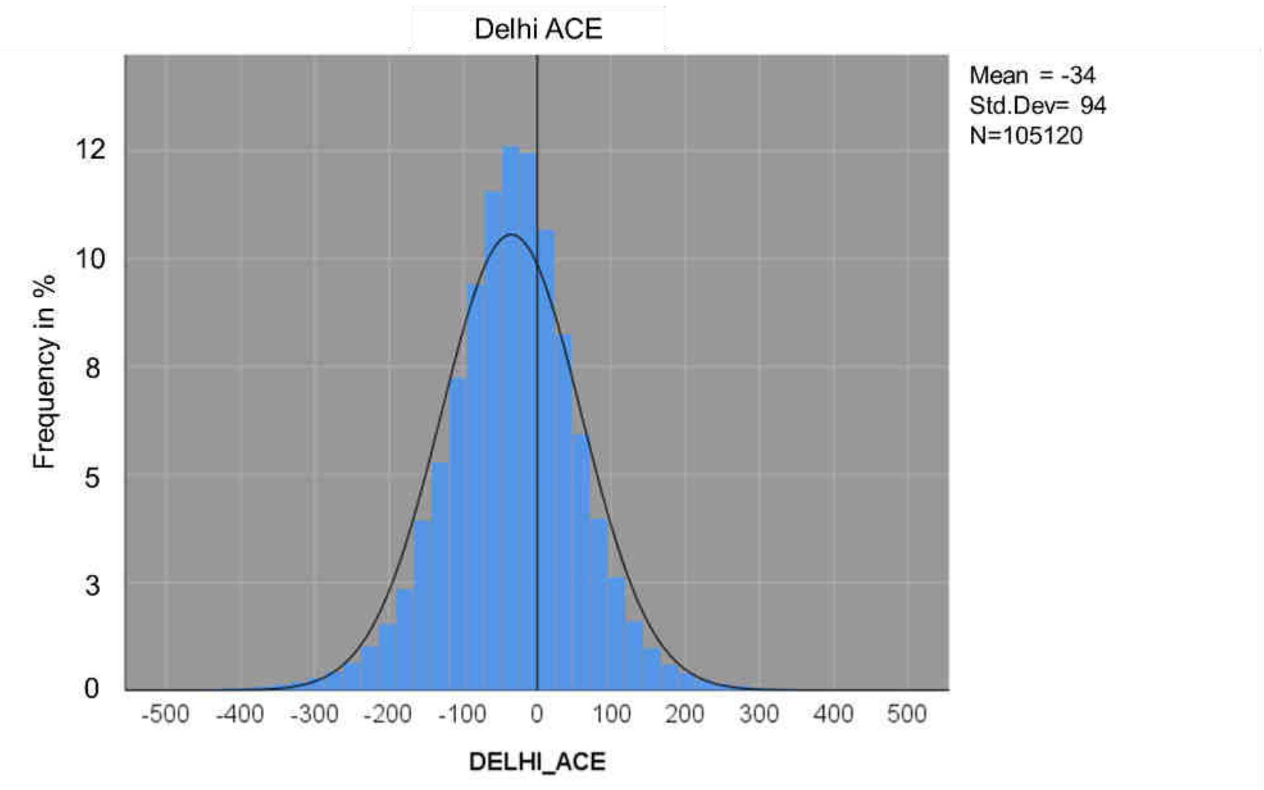


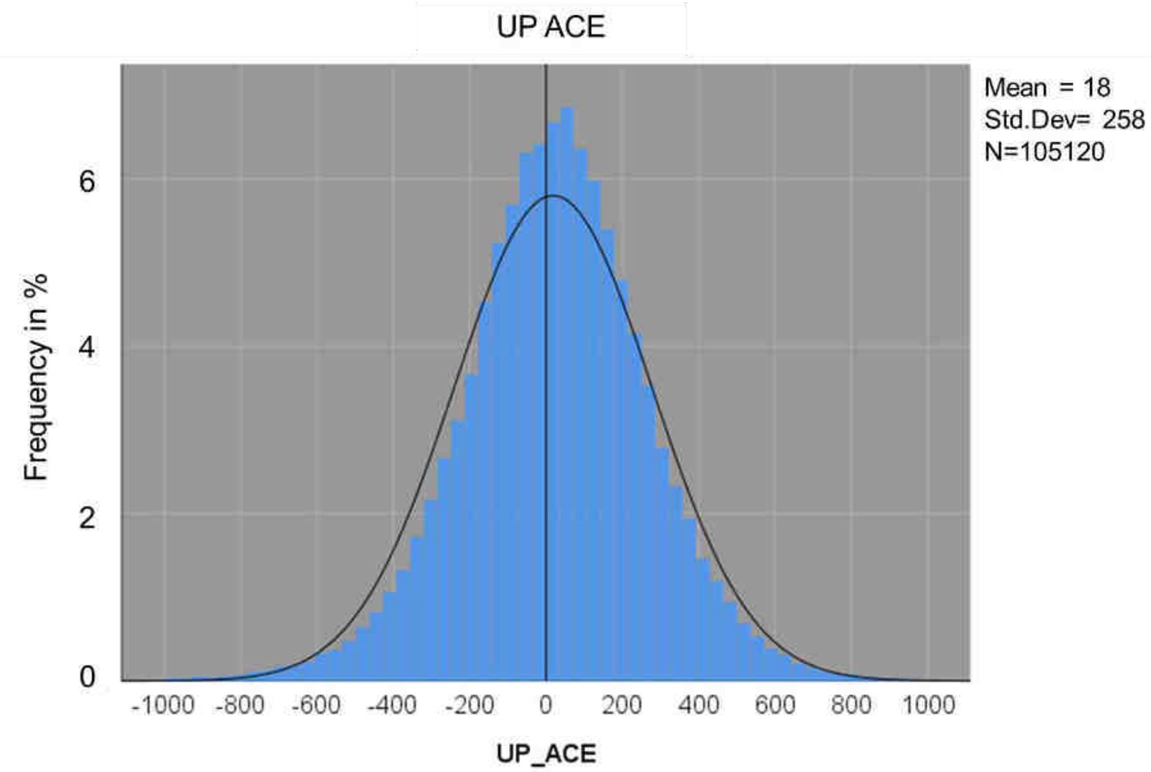
Puducherry ACE
Mean = -7
Std.Dev= 25
N=525600
Frequency in %
19
15
11
8
4
0
-200
-150
-100
-50
0
50
100
150
200
PY_ACE

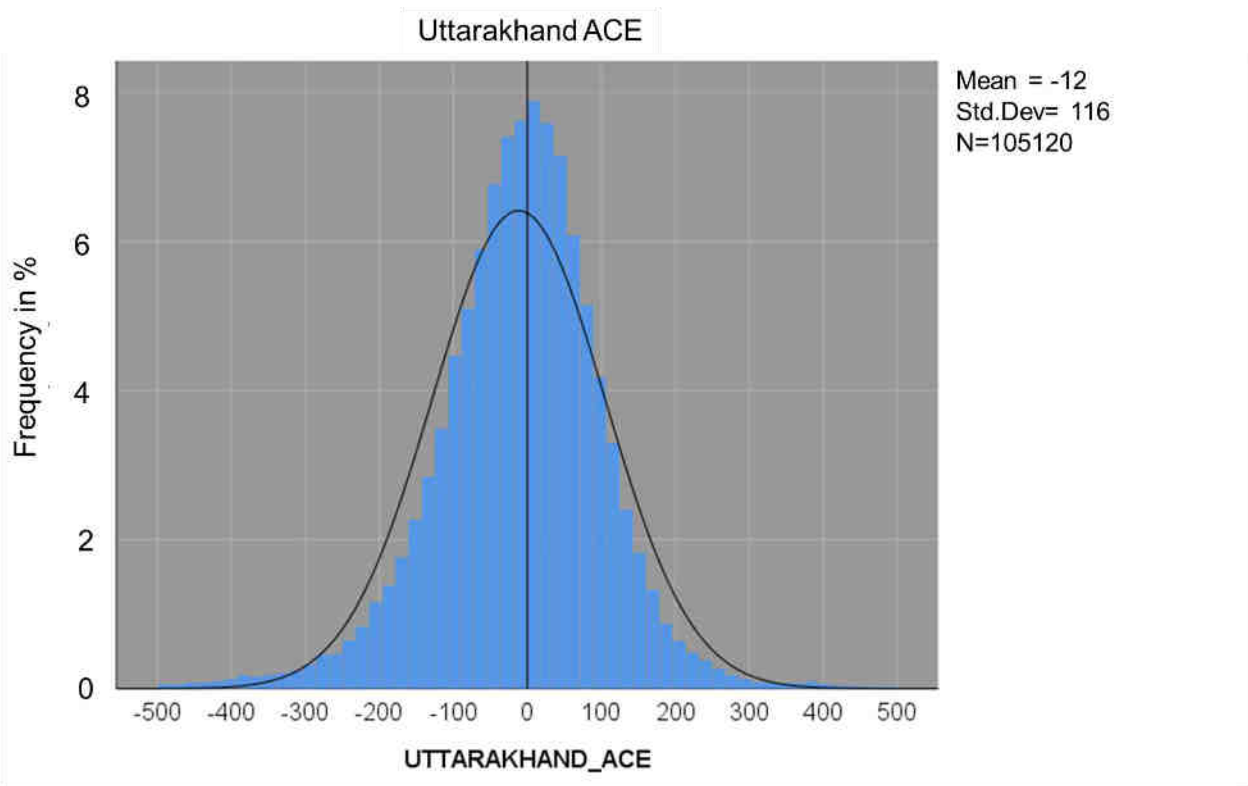


NR ACE
Mean = 43
Std.Dev= 563
N=105120
Frequency in %
6
4
2
0
-2500
-2000
-1500
-1000
-500
0
500
1000
1500
2000
2500
NR

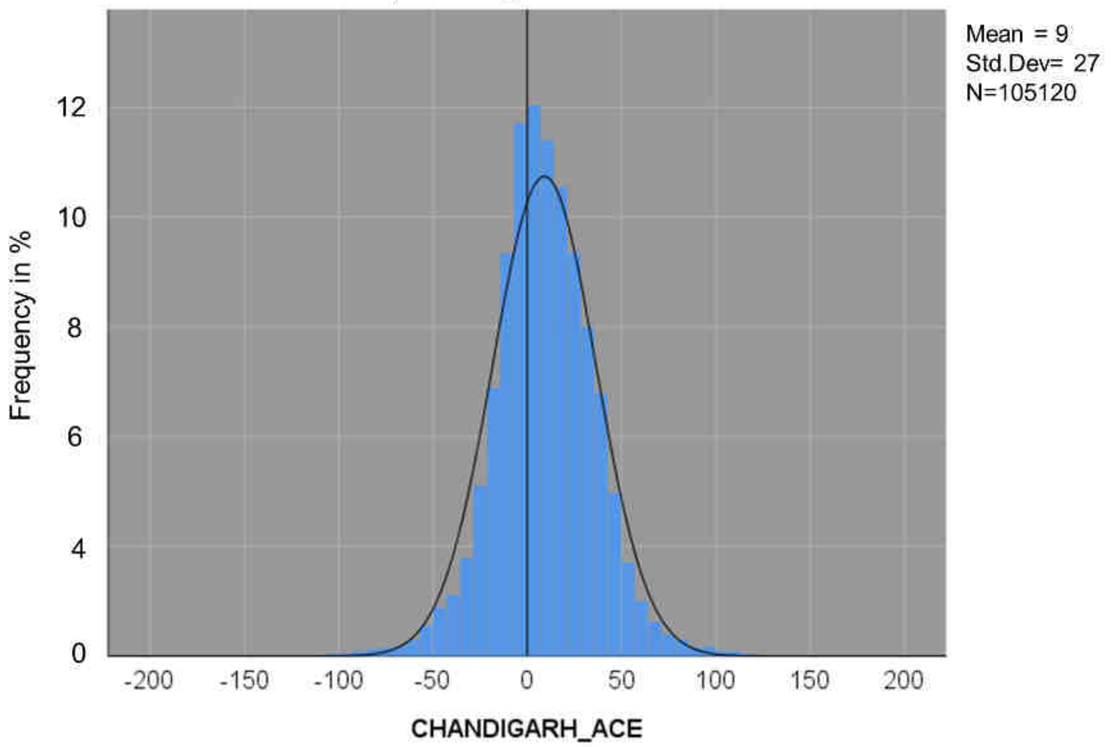

Punjab ACE
Mean = -32
Std.Dev= 157
N=105120
Frequency in %
20
15
10
5
0
-1000 -800 -600 -400 -200 0 200 400 600 800 1000
PUNJAB_ACE


Delhi ACE
Mean = -34
Std.Dev= 94
N=105120
Frequency in %
12
10
8
5
3
0
-500 -400 -300 -200 -100 0 100 200 300 400 500
DELHI_ACE

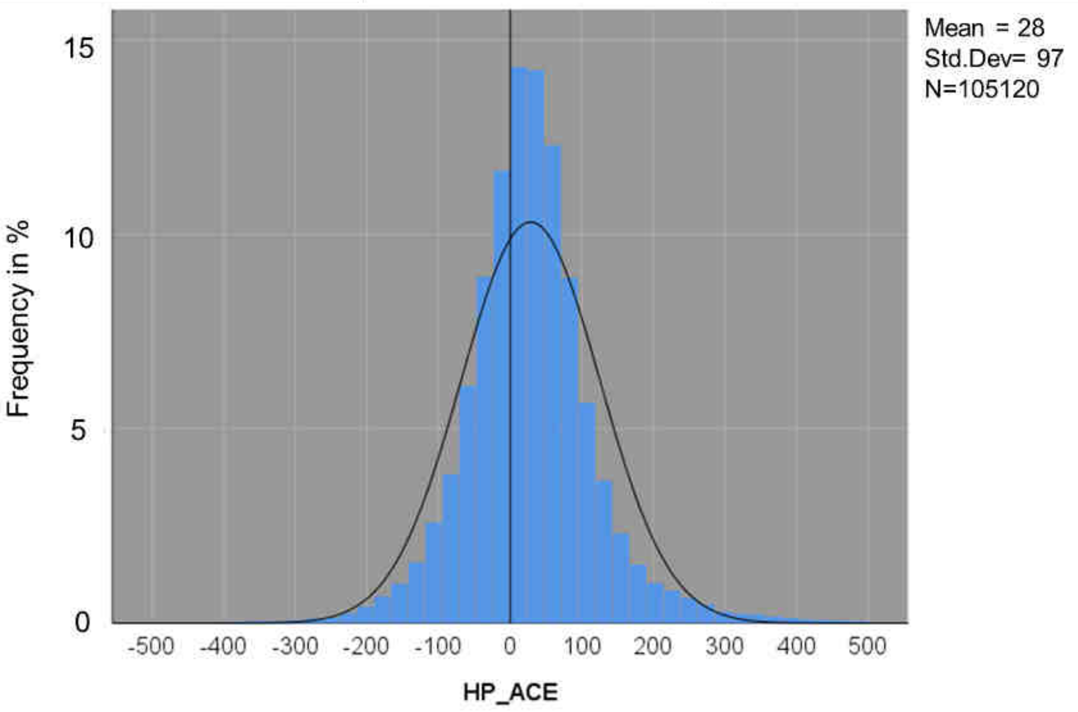

UP ACE
Mean = 18
Std.Dev= 258
N=105120
Frequency in %
0
2
4
6
-1000
-800
-600
-400
-200
0
200
400
600
800
1000
UP_ACE

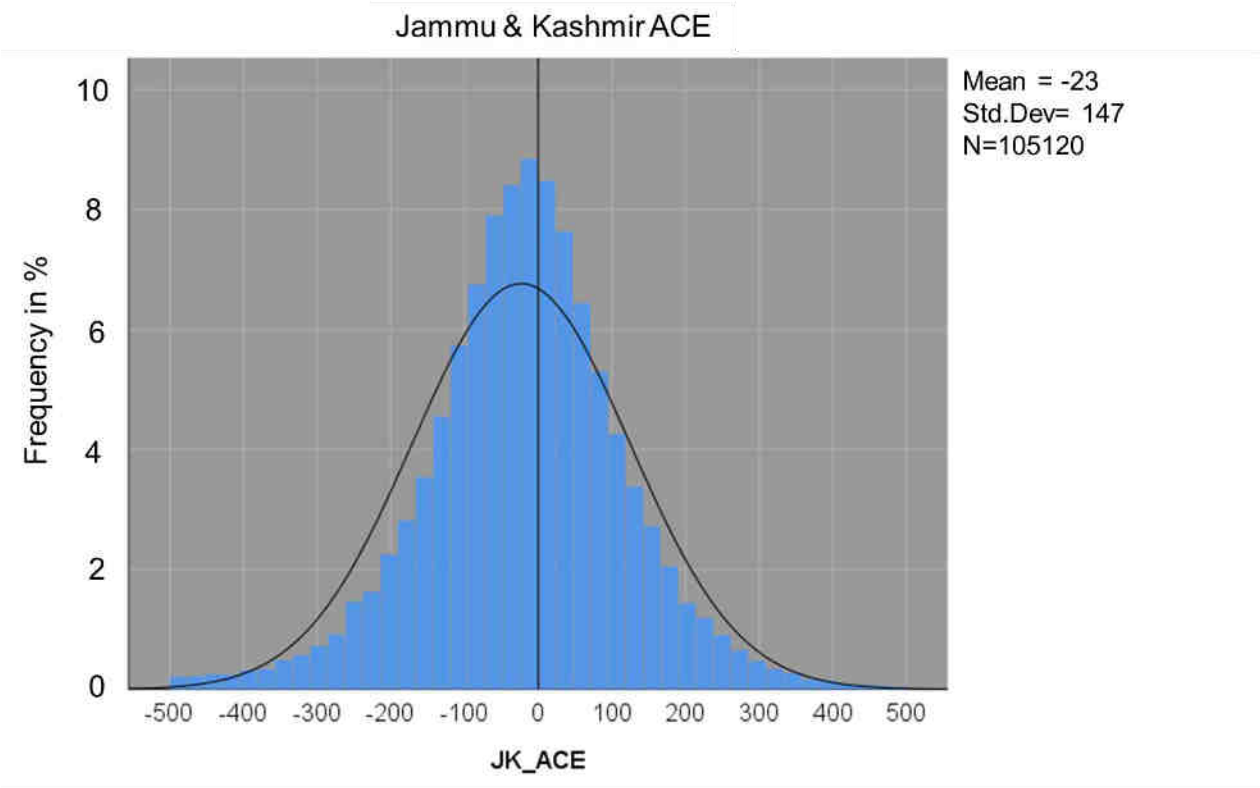

Uttarakhand ACE
Mean = -12
Std.Dev= 116
N=105120
Frequency in %
0
2
4
6
8
-500
-400
-300
-200
-100
0
100
200
300
400
500
UTTARAKHAND_ACE

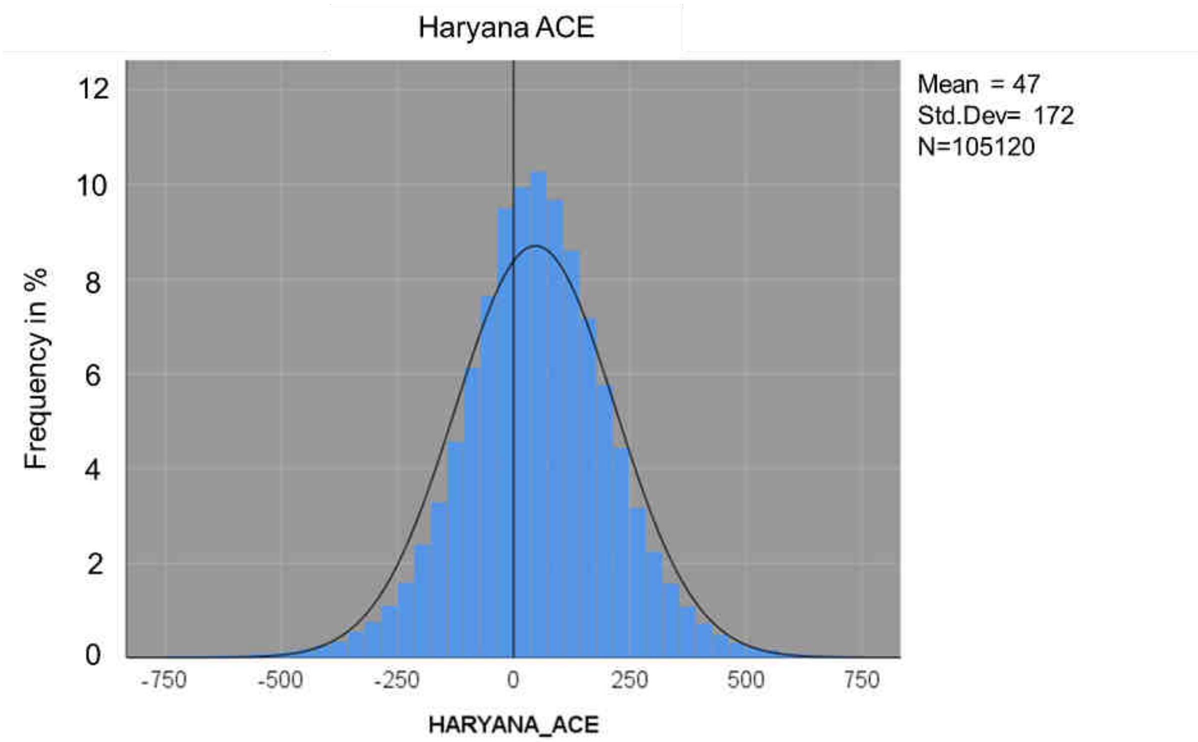
Chandigarh ACE

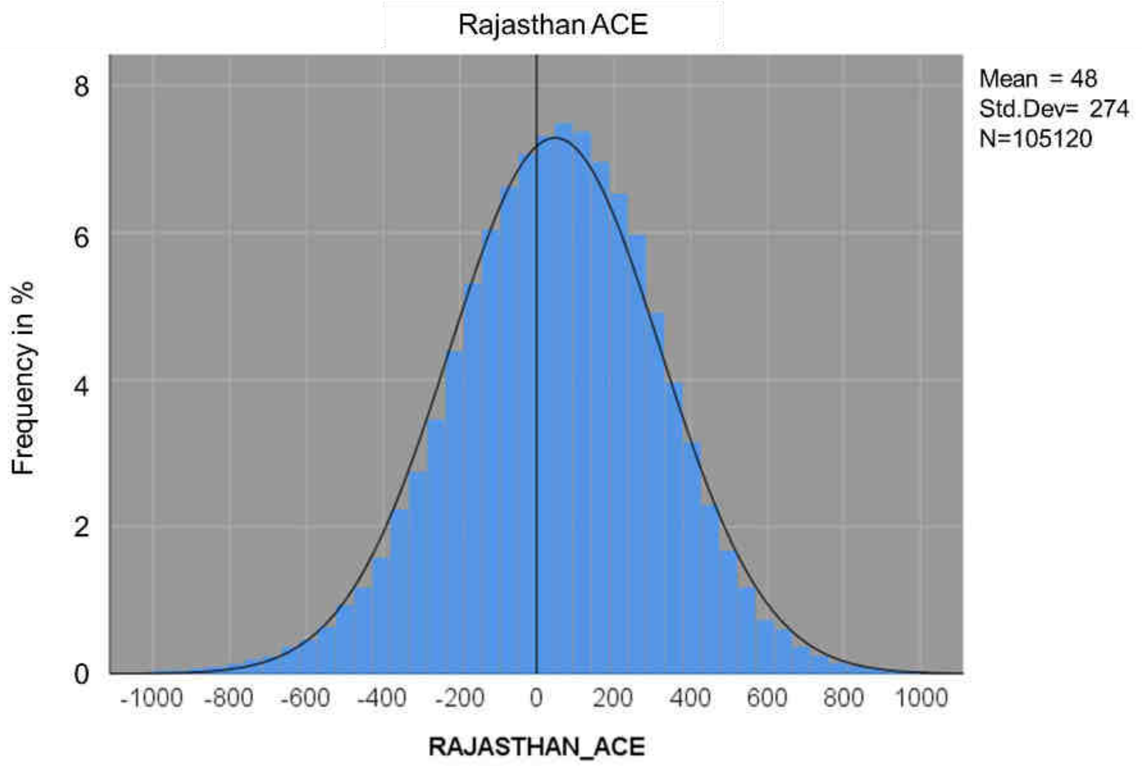


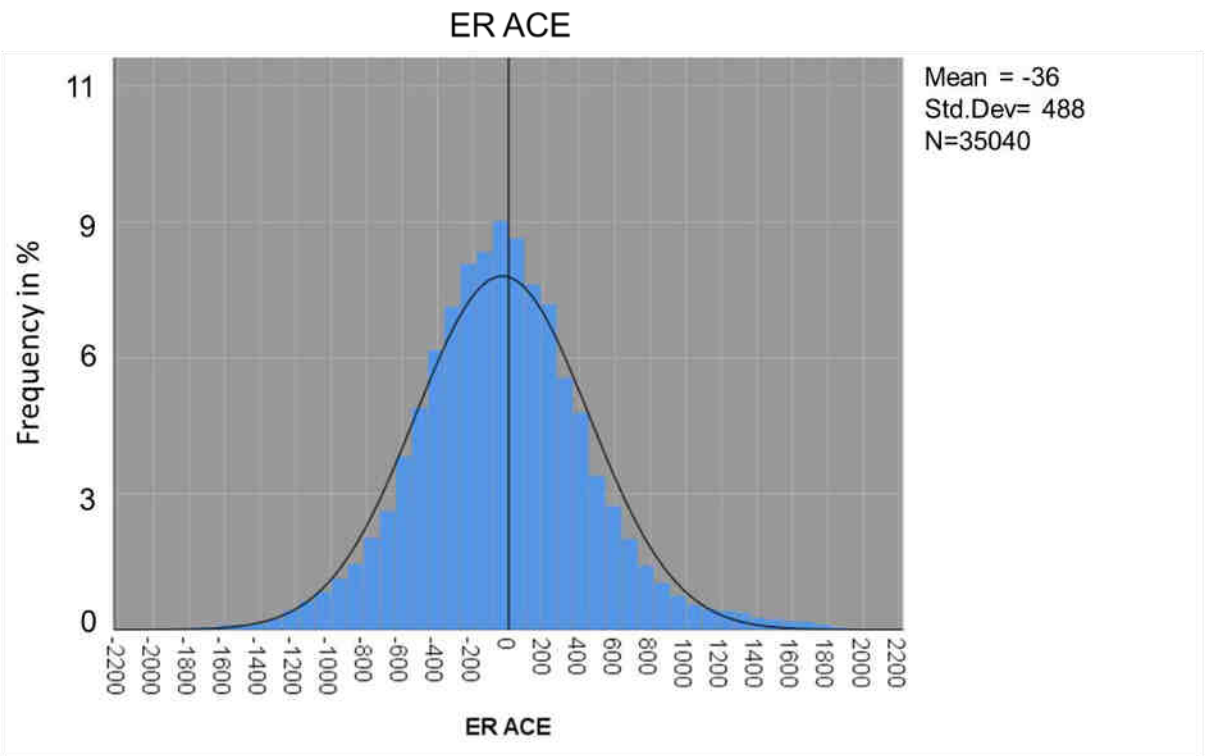
Himachal Pradesh ACE

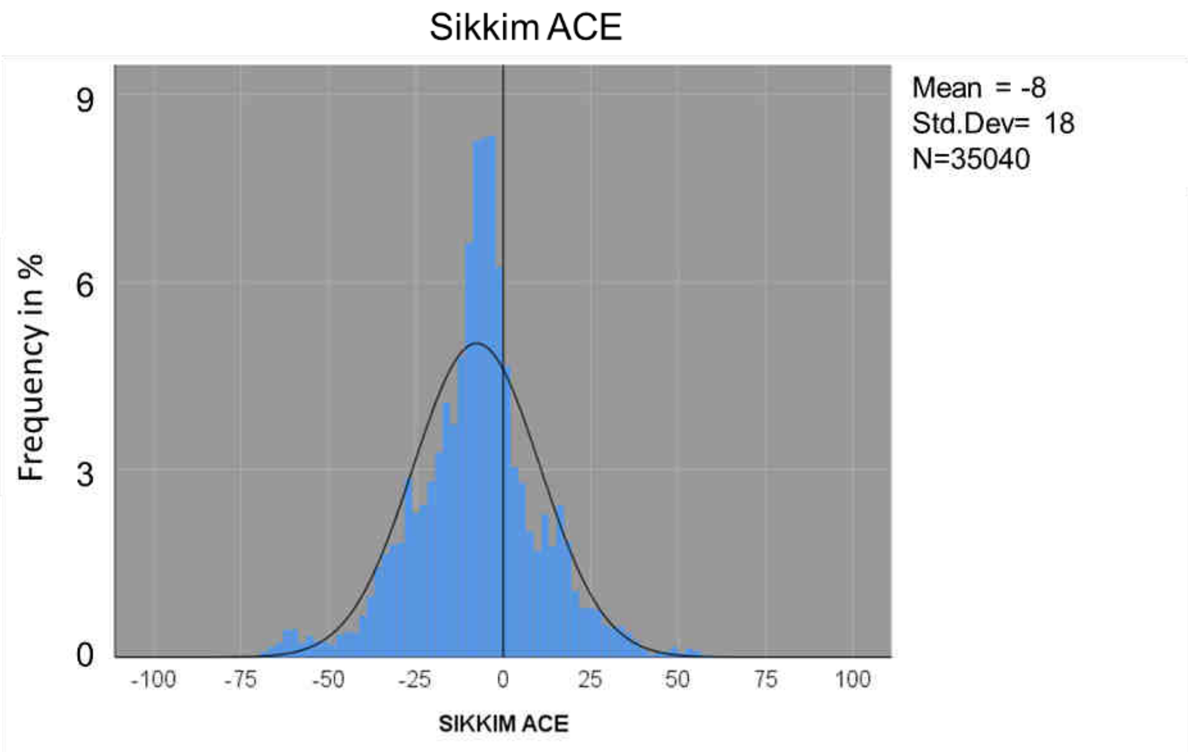


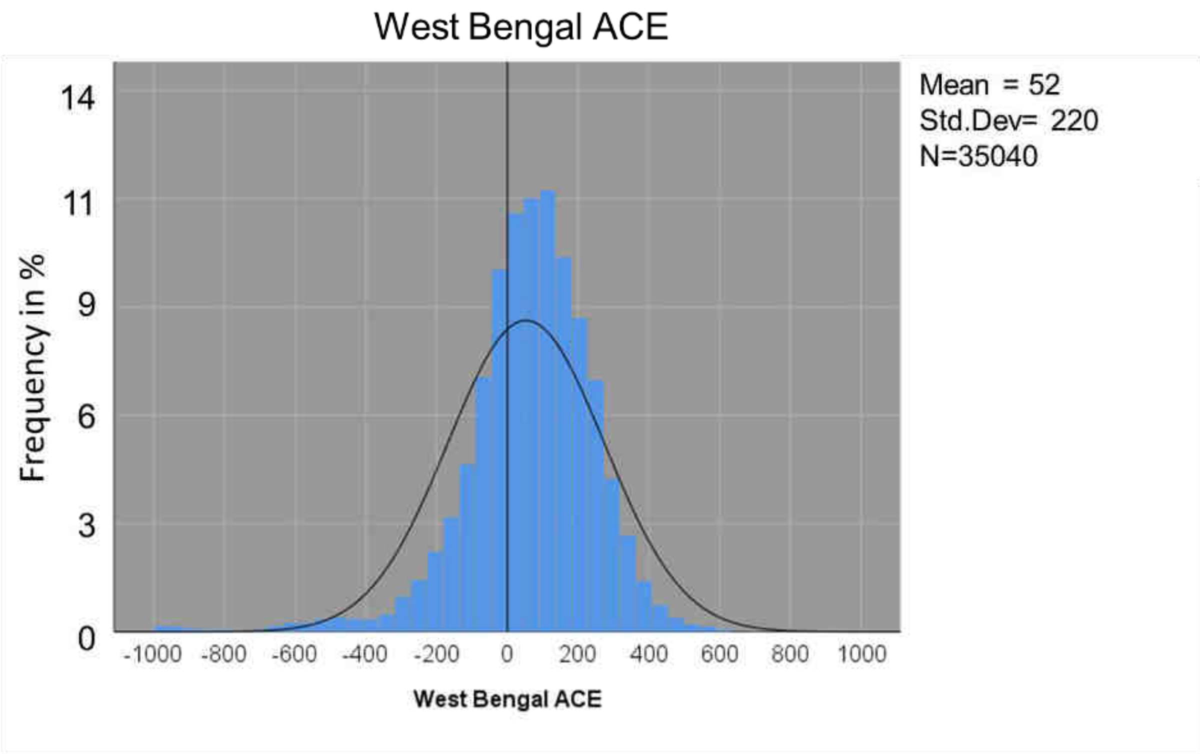

Jammu & Kashmir ACE
Mean = -23
Std.Dev= 147
N=105120
Frequency in %
10
8
6
4
2
0
-500 -400 -300 -200 -100 0 100 200 300 400 500
JK_ACE


Haryana ACE
Mean = 47
Std.Dev= 172
N=105120
Frequency in %
12
10
8
6
4
2
0
-750 -500 -250 0 250 500 750
HARYANA_ACE

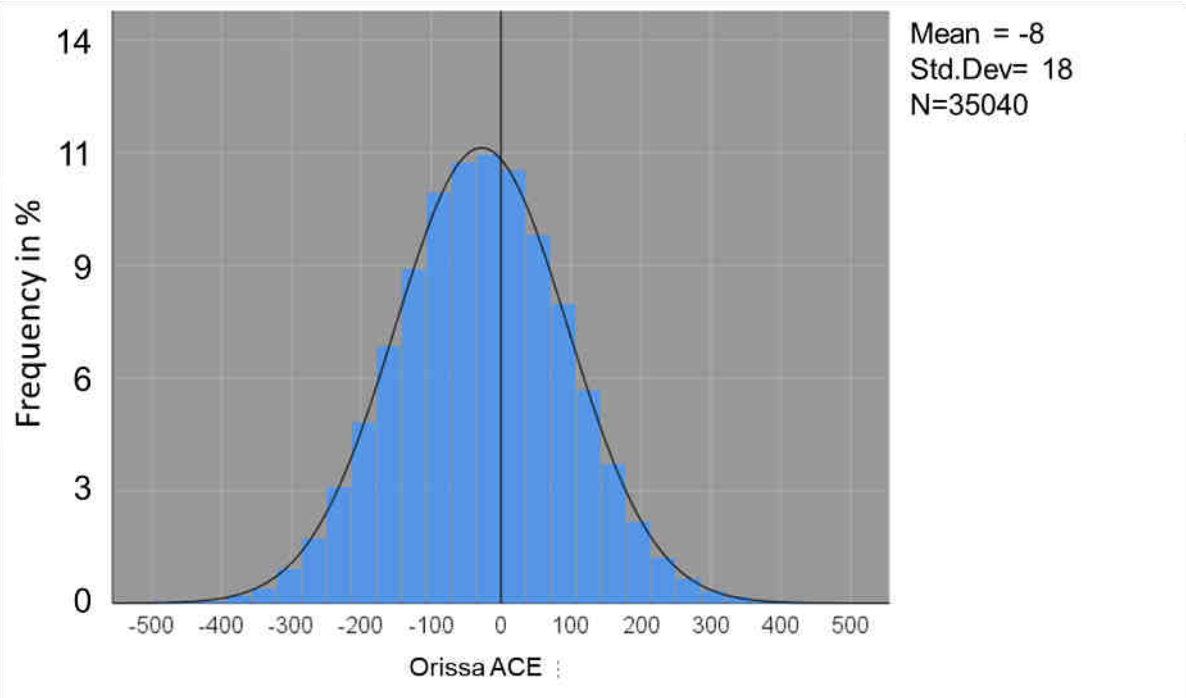

Rajasthan ACE
Mean = 48
Std.Dev= 274
N=105120
Frequency in %
8
6
4
2
0
-1000 -800 -600 -400 -200 0 200 400 600 800 1000
RAJASTHAN_ACE


ER ACE
Mean = -36
Std.Dev= 488
N=35040
Frequency in %
11
9
6
3
0
-2200 -2000 -1800 -1600 -1400 -1200 -1000 -800 -600 -400 -200 0 200 400 600 800 1000 1200 1400 1600 1800 2000 2200
ER ACE

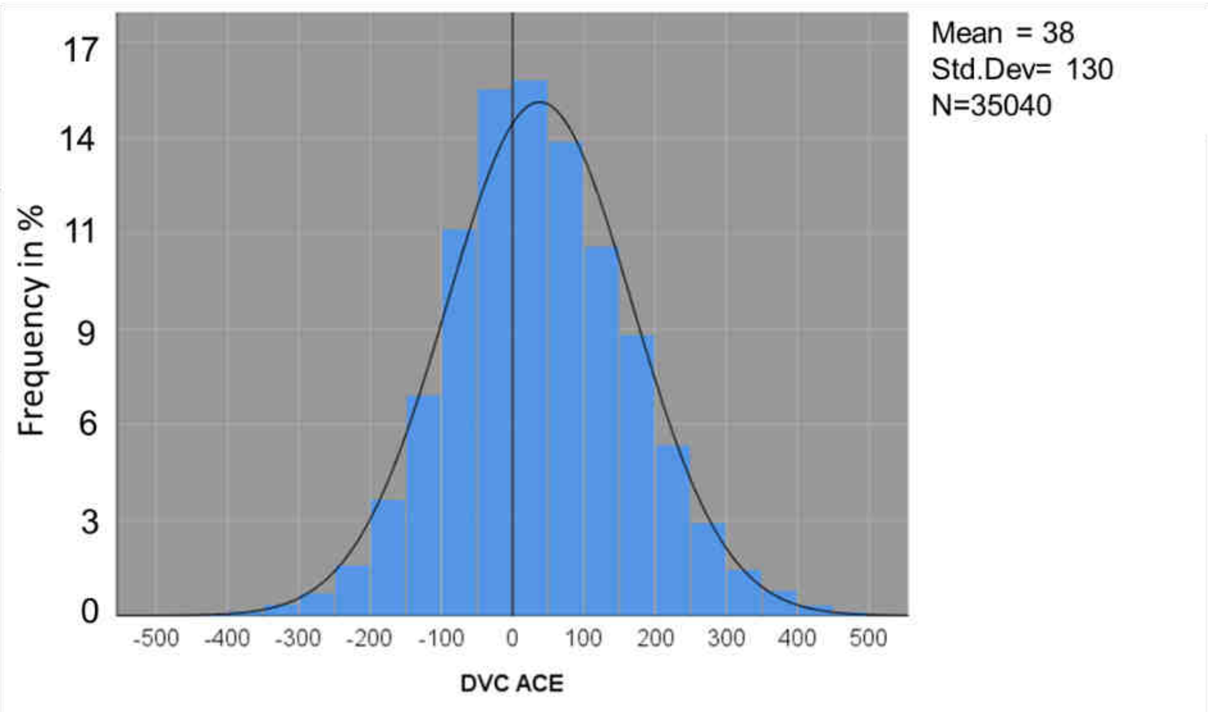

Sikkim ACE
Mean = -8
Std.Dev= 18
N=35040
Frequency in %
9
6
3
0
-100
-75
-50
-25
0
25
50
75
100
SIKKIM ACE

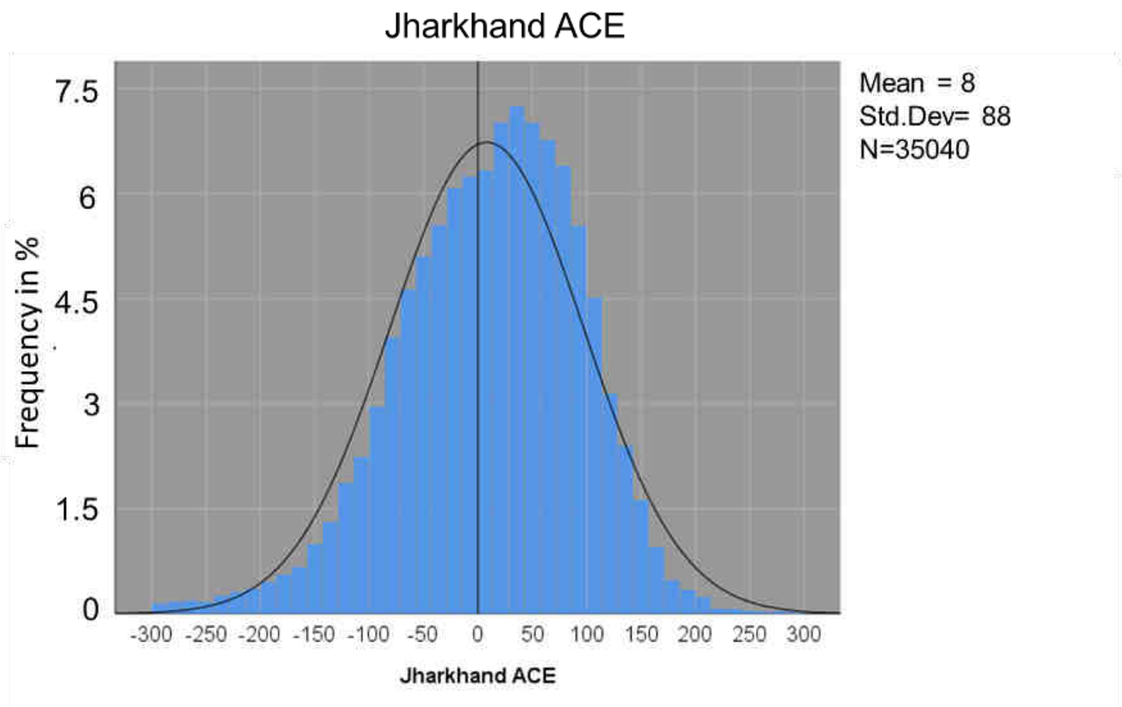

West Bengal ACE
Mean = 52
Std.Dev= 220
N=35040
Frequency in %
14
11
9
6
3
0
-1000
-800
-600
-400
-200
0
200
400
600
800
1000
West Bengal ACE

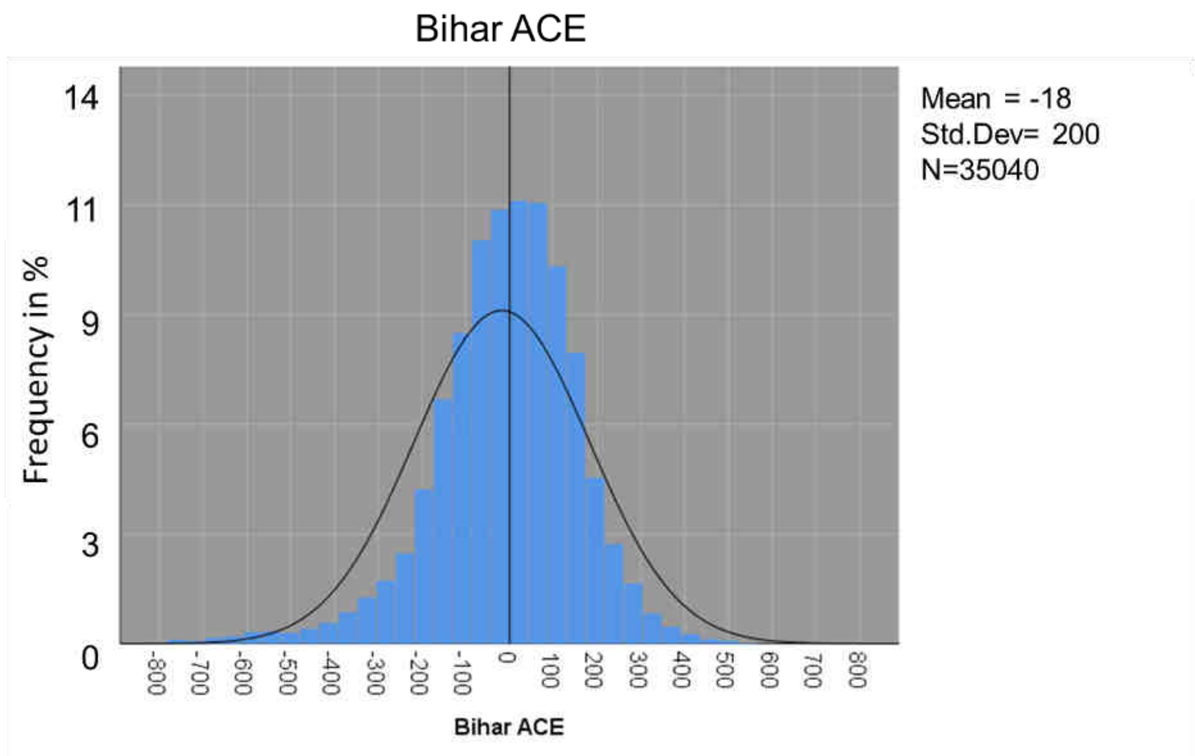
Orissa ACE

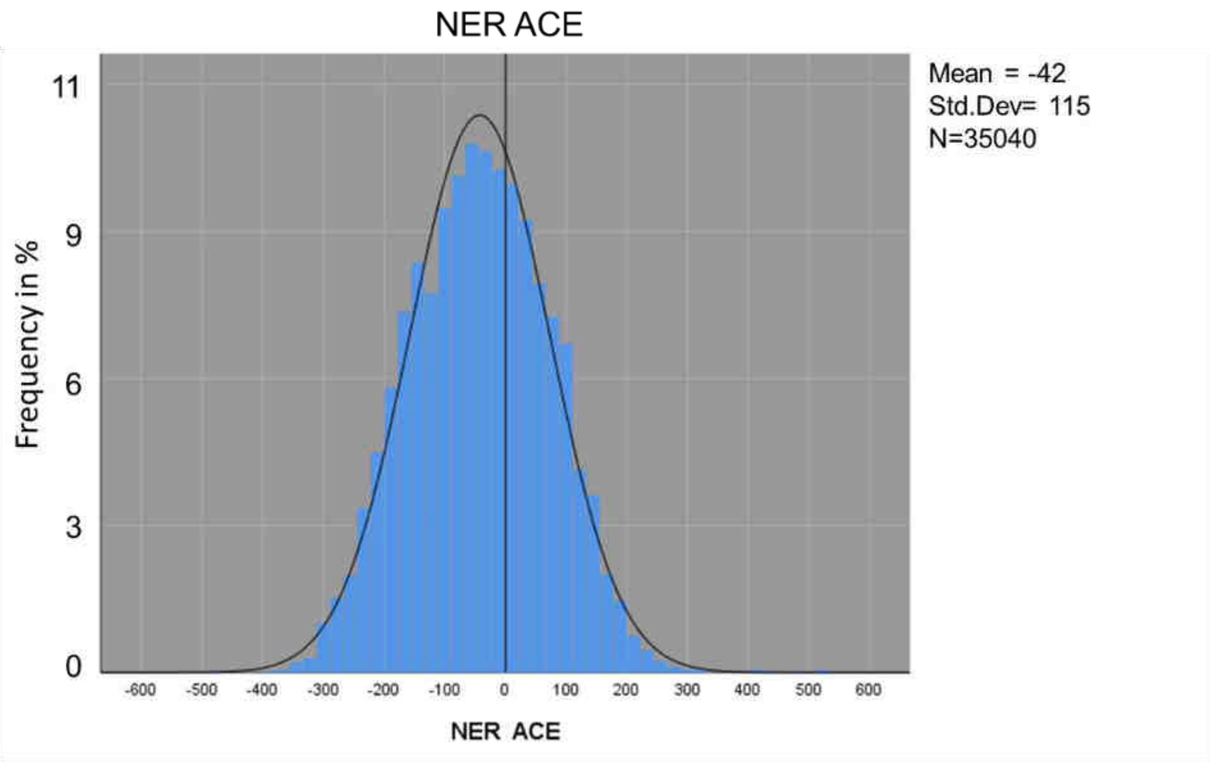


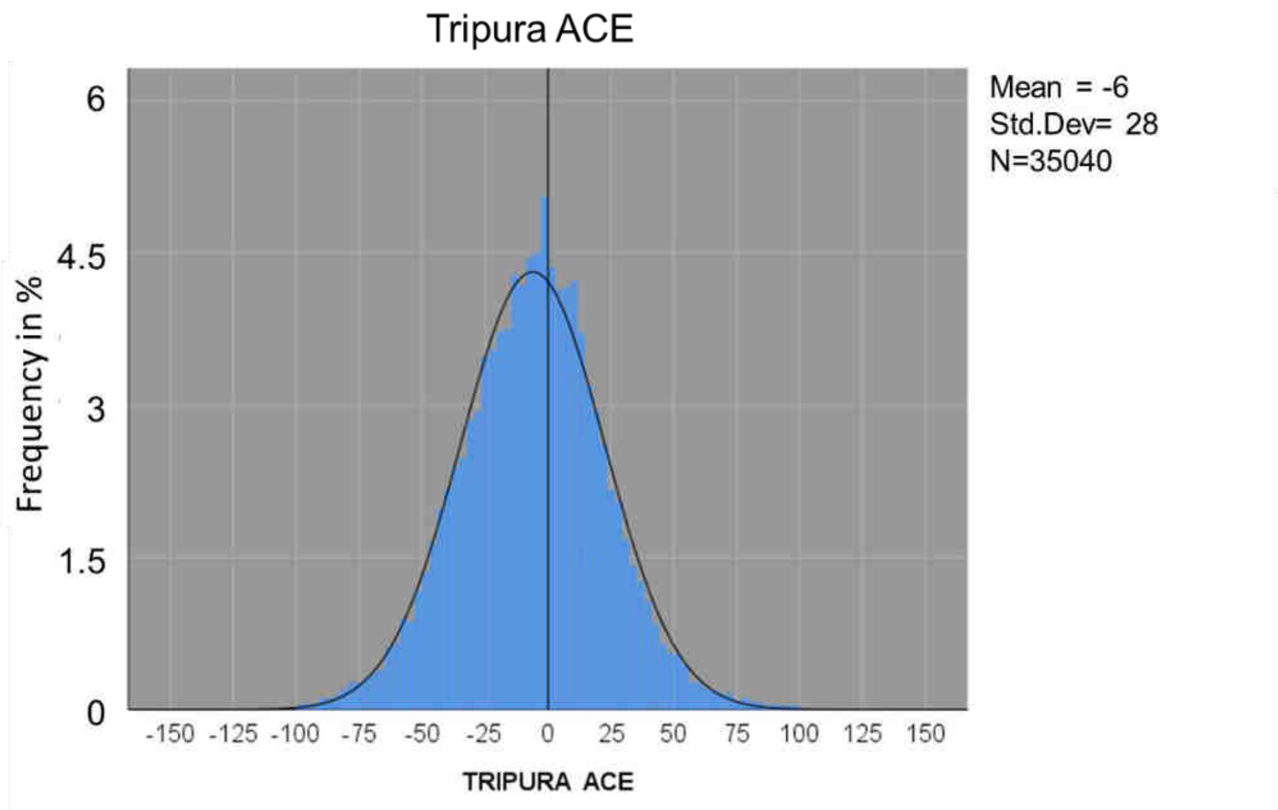
DVC ACE



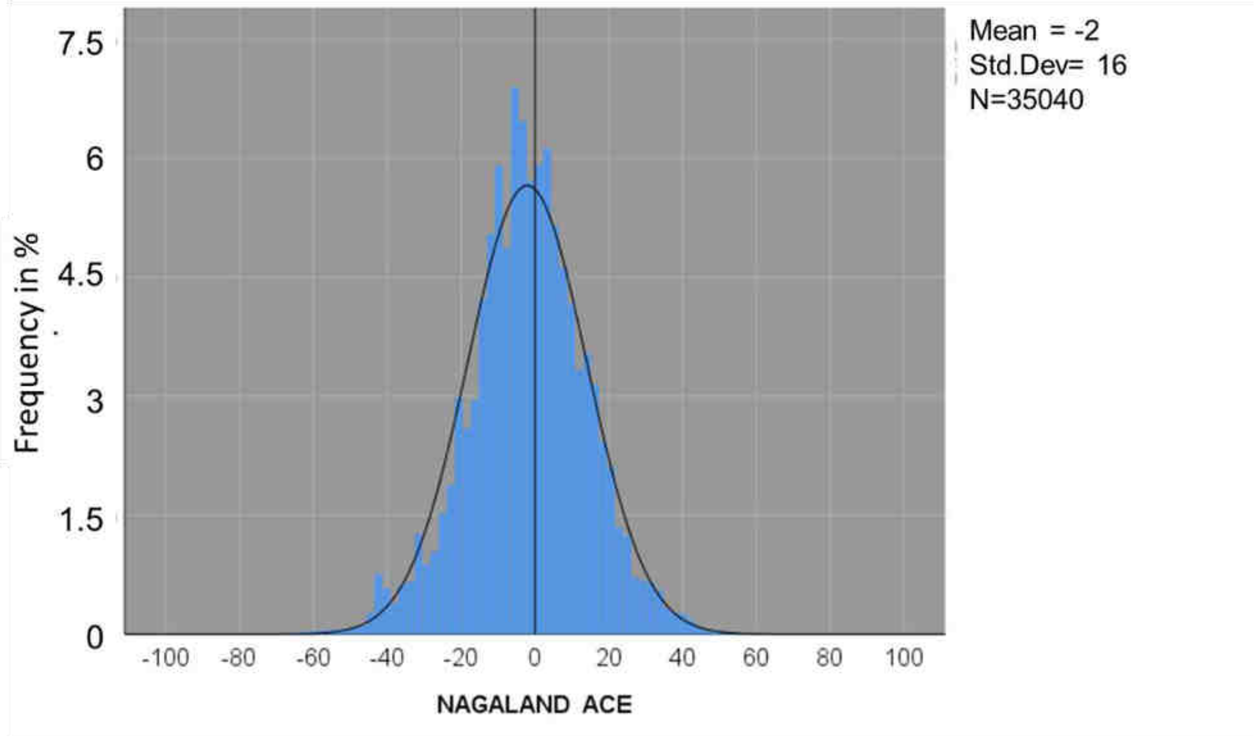

Jharkhand ACE
Mean = 8
Std.Dev= 88
N=35040
Frequency in %
7.5
6
4.5
3
1.5
0
-300 -250 -200 -150 -100 -50 0 50 100 150 200 250 300
Jharkhand ACE


Bihar ACE
Mean = -18
Std.Dev= 200
N=35040
Frequency in %
14
11
9
6
3
0
-800 -700 -600 -500 -400 -300 -200 -100 0 100 200 300 400 500 600 700 800
Bihar ACE

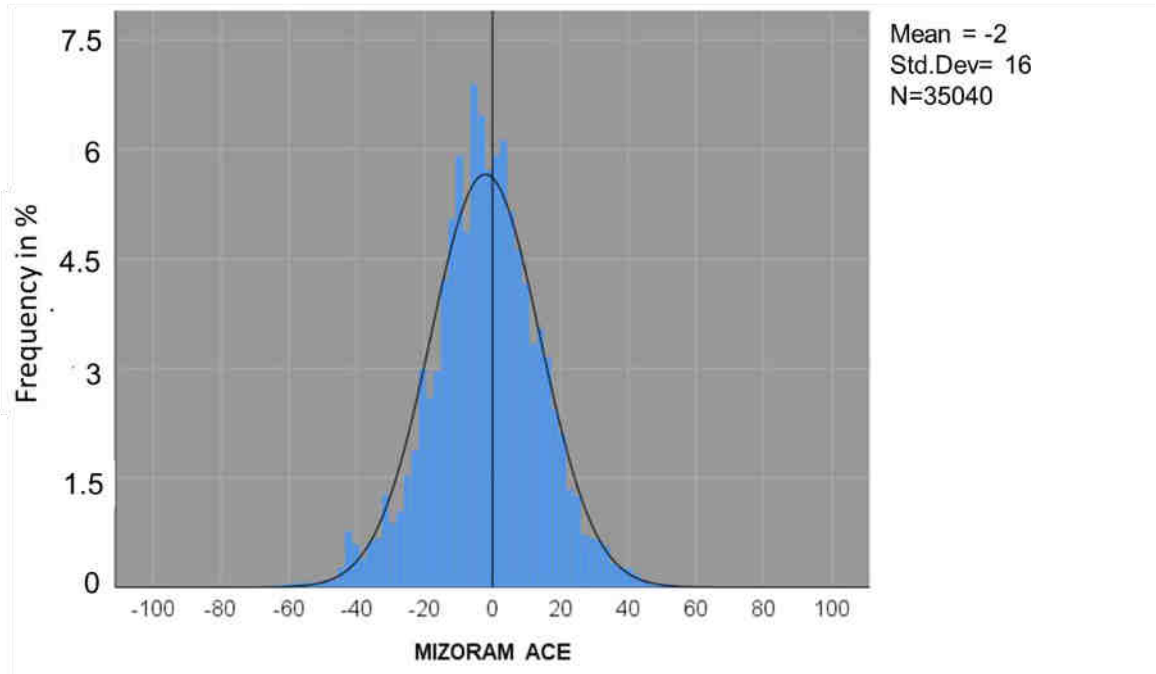

NER ACE
Mean = -42
Std.Dev= 115
N=35040
Frequency in %
11
9
6
3
0
-600 -500 -400 -300 -200 -100 0 100 200 300 400 500 600
NER ACE


Tripura ACE
Mean = -6
Std.Dev= 28
N=35040
Frequency in %
6
4.5
3
1.5
0
-150 -125 -100 -75 -50 -25 0 25 50 75 100 125 150
TRIPURA ACE

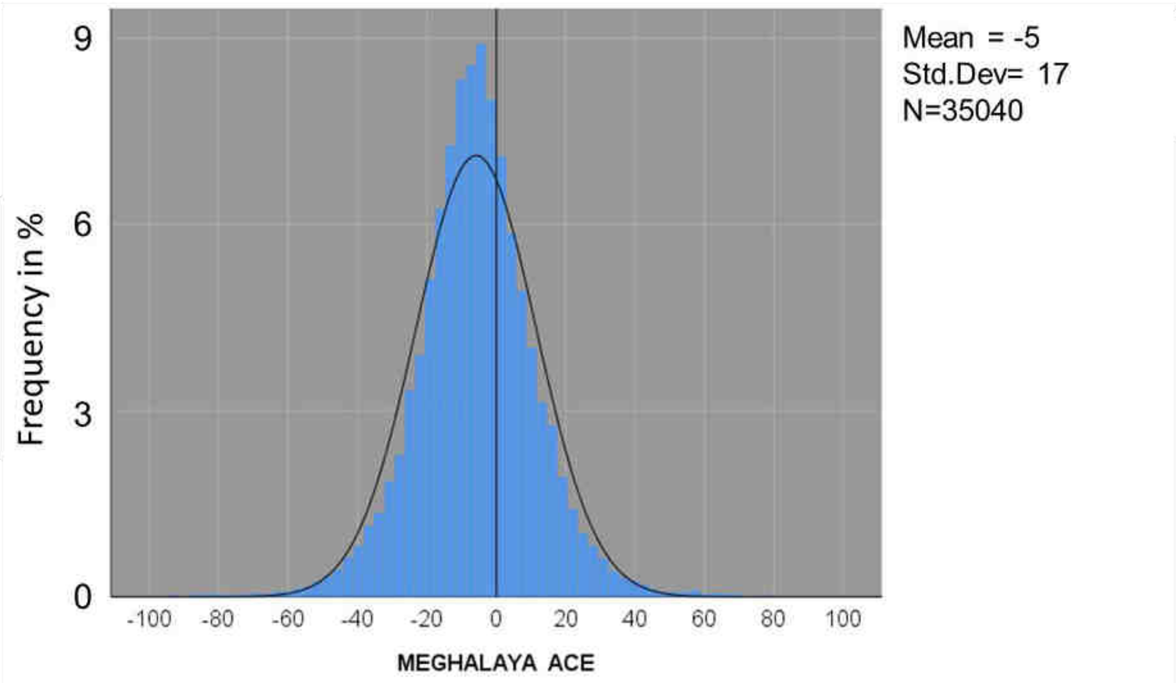
Nagaland ACE



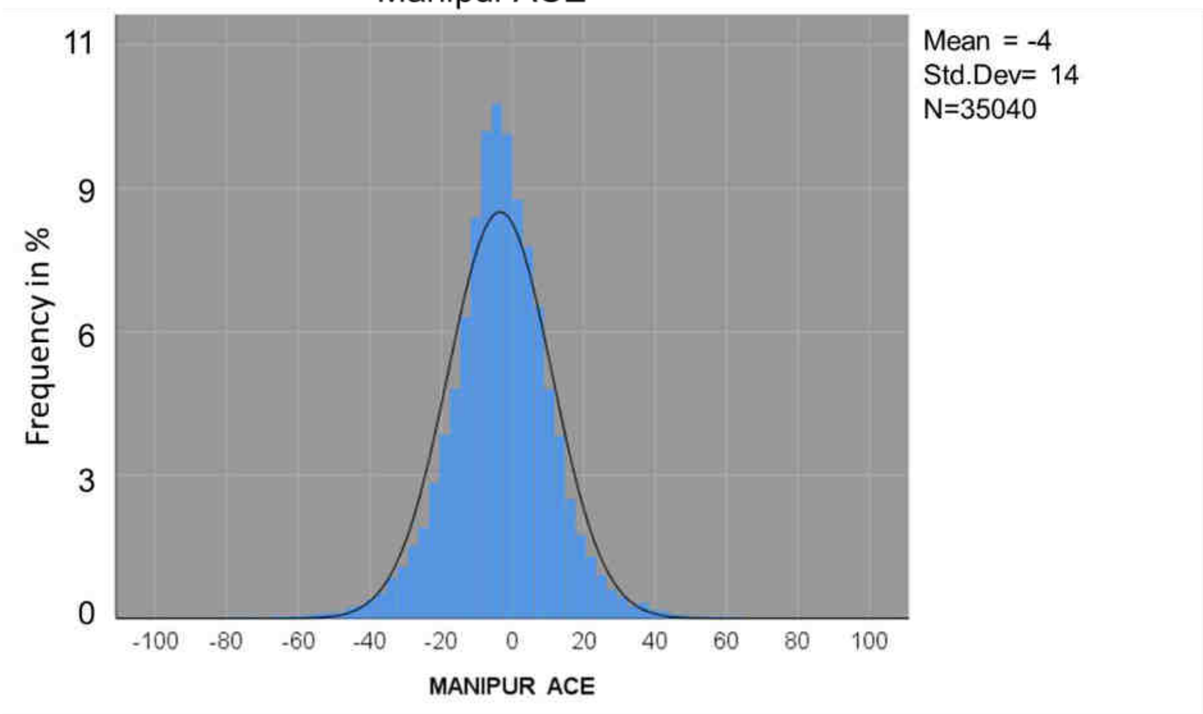
Mizoram ACE

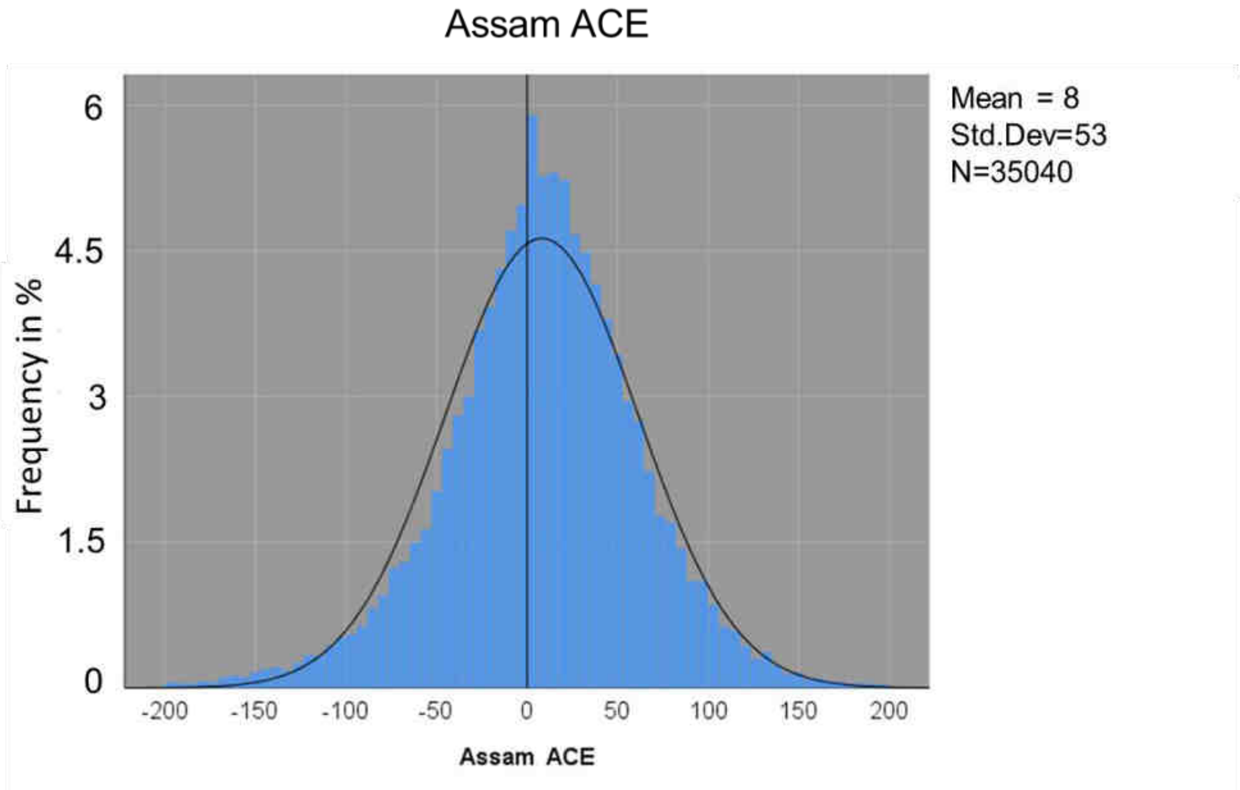


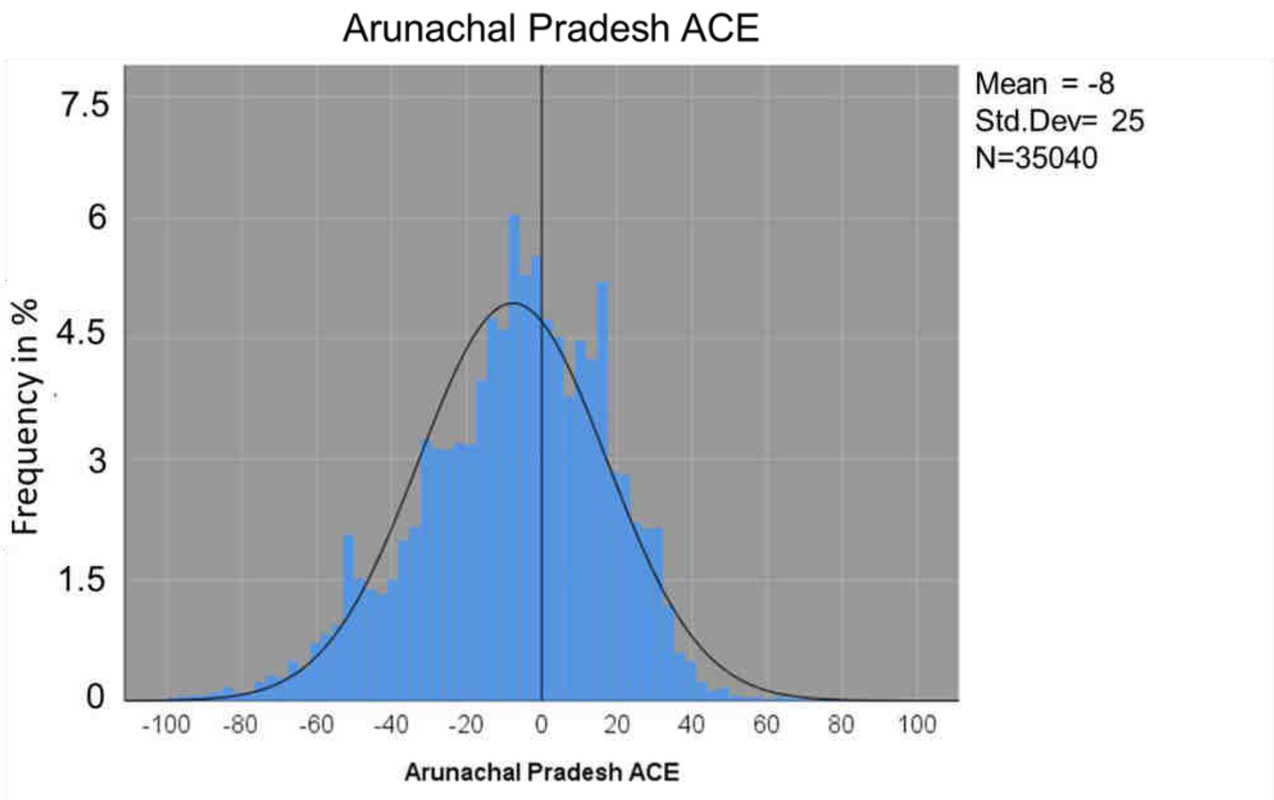
Meghalaya ACE



Manipur ACE



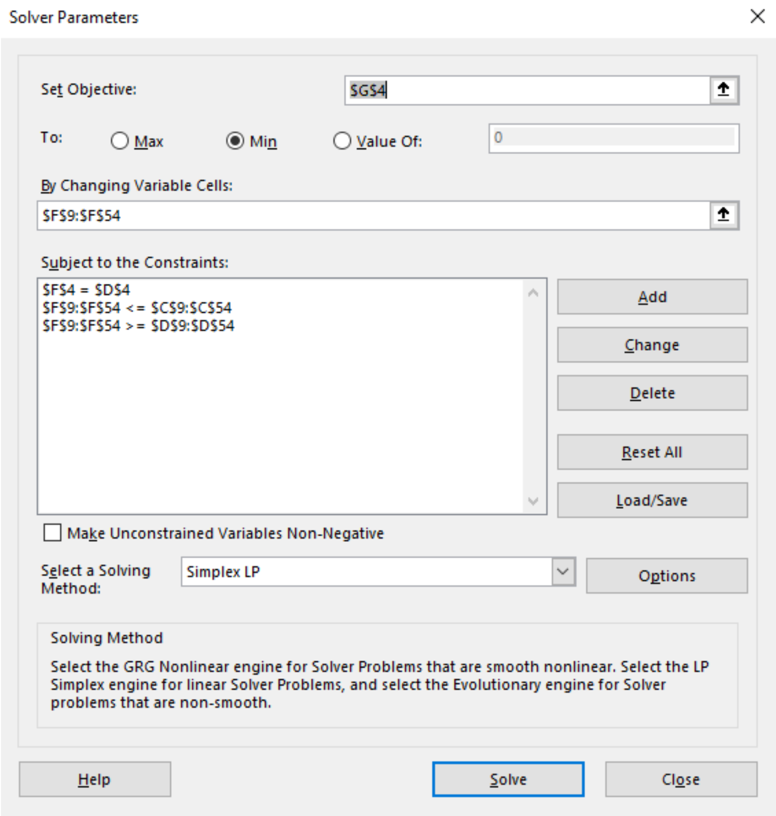

Assam ACE
Mean = 8
Std.Dev=53
N=35040
Frequency in %
6
4.5
3
1.5
0
-200
-150
-100
-50
0
50
100
150
200
Assam ACE


Arunachal Pradesh ACE
Mean = -8
Std.Dev= 25
N=35040
Frequency in %
7.5
6
4.5
3
1.5
0
-100
-80
-60
-40
-20
0
20
40
60
80
100
Arunachal Pradesh ACE

Annex-V: Optimization model developed in Microsoft Excel Solver

	A	B	C	D	E	F	G	H	I
1	Reserves / Ancillary Services		Despatch Model :	Madhya Pradesh		Total Schdl	Total Cost (Rs.Lac per hour)	Average Rate (Rs./unit)	Net UP Reserve Avail
2			Forecast Demand	4363			83	1.77	1313
3			Reserve	330			Total Cost (Rs./hour)	SMP	Net Down Reserve Avail
4	17.06.19	50 block	Total Demand	4693		4693	8283965	3.33	1238
5			Tech. Min (%)	0.70					
6	Column Name -->		A	B	C	D	E=C*D	F	G=D-F
7	Column Totals -->		7964	3004		4693		4758	-65
8	S No	Station Name	P Max	Pmin	Variable Charge	Schedule for Block 'T'	Production Cost	Schedule for Block 'T-1'	Difference in Schedule of Blocks T & T-1
9	1	JP Nigrie	417.28	277.20	64	417.28	267075	417.28	0
10	2	Rihand III (NR)	2.36	0.00	132	2.36	3113	2.36	0
11	3	SIPAT I	105.48	0.00	133	105.48	140149	105.48	0
12	4	Rihand II (NR)	1.08	0.00	134	1.08	1451	1.08	0
13	5	Rihand I (NR)	1.94	0.00	134	1.94	2600	1.94	0
14	6	SIPAT II	158.02	0.00	137	158.02	216346	158.02	0
15	7	KSTPS-III	71.51	0.00	139	71.51	99751	71.51	0
16	8	KSTPS	405.31	0.00	142	405.31	573850	405.31	0
17	9	Sasan	1366.88	956.81	145	1366.88	1986890	1366.88	0
18	10	Singrauli (NR)	3.59	0.00	150	3.59	5371	3.59	0
19	11	ATPS (210MW) Chachai	193.00	135.00	160	193.00	308800	193.00	0
20	12	VSTPS-IV	266.21	0.00	175	56.21	98095	126.21	-70
21	13	VSTPS-V	131.37	0.00	176	0.00	0	0.00	0
22	14	VSTPS-III	211.93	0.00	177	0.00	0	0.00	0
23	15	VSTPS-II	138.99	0.00	179	0.00	0	0.00	0
24	16	VSTPS-I	355.45	0.00	184	0.00	0	0.00	0
25	17	SGTPS -1x500	470.00	350.00	197	350.00	689850	350.00	0
26	18	SGTPS -4x210	445.00	405.00	216	405.00	875610	405.00	0

Instructions | State_Details | +



Optimization Algorithm

Objective Function

Minimize the Statewide Total Variable Cost

Subject to Constraints

Meeting Total Requisition by Discoms from various sources

Technical Minimum of Plants

Maximum Generation (DC-on-bar)

Ramp up

Ramp down rates

Minimise $\sum_{i=1}^{k} C_i P_i$ ....(1)

- $k = total\ number\ of\ Plants$
- *Where* C_i *is the variable per unit cost of the* i^{th} *Plant*
- P_i *is the optimised scheduled power of the* i^{th} *Plant*

Subject to

- $\sum_{i=1}^{k} P_i = \sum_{i=1}^{k} S_i$ + *Reserve to be despatched through ancillary*. (2)
- $P_i \leq P_{i,max}$ ....(3)
- $P_i \geq P_{i,min}$ ....(4)
- $P_{i,t} \leq P_{i,t-1} + Ramp\ up\ rate$ ....(5)
- $P_{i,t} \geq P_{i,t-1} - Ramp\ down\ rate$ ....(6)

$Reserve\ available \geq$ Stipulated reserve (Through Unit commitment)

- S -is the scheduled power
- t -represents time block for which optimization is being carried out
- $P_{i,max}$ is max generation limit (DC on bar)
- $P_{i,min}$ is the *technical minimum* for thermal power plants (normally considered at 55% DC on bar)
- Reserve is the quantum of ancillary which is to be despatched for that period

Annex-VI: Pilot Project in Madhya Pradesh

Brief power profile of the State

As on October 2019, the state of Madhya Pradesh has an installed generation capacity of 23995 MW including state generation, independent power producers (IPPs) in the state and the state's share in central sector generation and jointly owned interstate generators. Out of the total generation capacity (~24 GW), 63% (15 GW) is coal-based generation, 20% (4.8 GW) renewable energy-based (RE) generation & 13% (3.2 GW) is hydro generation. In terms of annual energy generation in MUs for 2018-19, 85% of the generation energy came from thermal (coal+gas+nuclear) units, 6% from wind, 5% from hydro and 4% from solar units.

The state demand follows a seasonal pattern wherein the peak demand (~ 13-14 GW) season typically falls in winter (December to February) where-as lean demand is registered in the monsoon season (July-September). Typically, the state demand undergoes a diurnal variation (i.e. difference between intra-day max. and min. demands) of 5000-6000 MW during winter and 1500-2000 MW during the summer. A maximum state demand ramp of ~ 200 MW per block has been observed during onset of morning peak. Daily energy consumption varies between 220 MUs in lean demand period to 270 MUs during peak demand period. With an installed renewable generation capacity of 4.8 GW Madhya Pradesh is considered a renewable rich state which has so far witnessed a maximum RE penetration of 48% in terms of %age of instantaneous state generation. RE generation contributes to 9.4% of net annual energy consumption by the state. Maximum intra-day wind generation variation (Max-Min) stood at 1563 MW on 25.05.18. Typically, the daily wind generation pattern follows the demand pattern during April to September where as the wind generation follows a reverse pattern to demand during the of the period (October to March).

Forecasting

As per 20th FOLD recommendations, SLDC MP has engaged Indian Institute of Information Technology, Jabalpur for Development of a load forecasting model for daily, weekly, monthly, seasonal and annual load forecasting.

Scheduling

MP-SLDC computes schedule for the intra-state entities. As on August 2019 the different category of intra-state entities scheduled by SLDC Madhya Pradesh are given below.

Table 15: Entities scheduled by SLDC Madhya Pradesh

S No	Category	Number
1	Distribution Licensees	5
2	Open Access Customers	6
3	Thermal Power Stations	10

4	Hydro Stations	12
5	Solar Power stations	48
6	Wind Power stations	62
	Total	**143**

Contracts scheduled by SLDC, Madhya Pradesh for a typical day are summarized below:

Table 16: Contracts scheduled by SLDC Madhya Pradesh (2019)

S.No.	Type	Number	MW / MU		Maximum in a Day	
Inter State (+ve : Import; -ve : Export)						
1	Long Term PPA	32	7226	MW		
2	Long Term (Hydro+RE)	6	1470	MW		
3	Short Term Inter-state (Typical transactions in a Day)					
	1. 23.08.19	26	-231.53	LU	-1507	MW
	2. 23.05.19	13	-170.25	LU	-1027	MW
	3. 02.01.19	19	245.38	LU	2143	MW
Intra State						
1	Long Term PPA	10	5781	MW		
2	Long Term (Hydro+RE)	20	6654.14	MW		
3	Short Term (Typical in a Day)					
	1. 23.08.19	4	6.52	LU	28.15	MW
	2. 23.05.19	3	6.40	LU	27.65	MW
	3. 02.01.19	1	1.30	LU	5.4	MW

Scheduling Time line

Day ahead & real time scheduling coordination is done by SLDC with intra-state entities and WRLDC as per a specified time line in line with MP state grid code & Balancing and Settlement Code (BSC) 2015. The following table summarizes the different time lines followed for scheduling activities at SLDC.

Table 17: Scheduling Time line (SLDC Madhya Pradesh)

D-1 day (hh:mm)	Activities on Day-ahead horizon
10:00	15 minute time block wise Capability declaration (DC) for next day by Intra-state generators/IPPs/Shared plants; ISGS entitlements taken from WRLDC website
10:30	Entitlement Computation by SLDC MP for state DISCOMs; The state DISCOMS convey their requsition / forecast demand for next day to MPPMCL
11:00	MPPMCL aggregates the forecast demand & cumputes likely surplus / deficit for nexy day and decides on the position (buy/sale) to be taken in the PX.

13:30	MPPMCL after receiving provisional transaction report from PX and runs merit order dispatch module for next day followed by DISCOM wise power allocation from different power stations/PX.
14:00	MPPML informs SLDC, the DISCOM wise Ex-PP requistion from each power plant including LTA, MTOA & STOA contracts
15:00	SLDC MP intimates WRLDC the composite requisition of the state at regional boundary
17:00	WRLDC intimates the 15 min wise drawal schedule of Madhya Pradesh for next day
17:30	After receipt of the final transaction report, MPPMCL runs the MOD & allocates power time block wise to each state DISCOM as per their demand forecast & entitlement;
18:00	MP-SLDC issues ex-PP injection schedule to generators & ex-STU periphery drawal schedule to DISCOMs (R0)
21:30	State Generators, IPPs inform any foreseen revision in their availability for next day
22:00	SLDC MP intimates WRLDC revised requisition for the state for next day (if any)
23:30	Revised Schedule (R-1) for next day issued by SLDC for all generators and DISCOMs
D-Day	**Activities on the day of operation**
00-24 hrs	MPPMCL initiates revisions (if any) as requested by the DISCOMs; State Generators initiate DC revision (if any); SLDC-MP incorporates these accordingly;
	Activities after the day of operation
By D'+3	**MP-SLDC issues final implemented schedule for D-day after receipt of implemented schedule from WRLDC (on D' day)**
NB:	All Hydro Power Stations of Madhya Pradesh Power Generating Company Limited furnish day ahead DC as per MPERC (Terms and conditions for determination of Generation Tariff) Regulations, 2012 and amendments thereof;

Merit Order Dispatch (MOD) & Unit Commitment:

- MOD stack is prepared by the holding Distribution Company (MP Power Management Company Ltd - MPPMCL) on behalf of the state discoms, based on VC as per latest (last month’s) bill issued by the state generators.
- MOD is submitted by MPPMCL to SLDC on monthly basis by 10th -15th day of every month. The VC of ISGS stations used in MOD preparation factors in the point of connection (POC) transmission loss component.

- MPPMCL is allowed to revise the allocation to the state-DISCOMs on the actual day of operation based on load-generation balance requirement.
- MPPMCL runs the MOD & the unit commitment (UC) software.
- During low demand period reserve shut down decision is taken by MPPMCL in consultation with MP-SLDC.

Generation Tariff Structure

MPERC (Terms & Conditions of Tariff) Regulations 2015 is the guiding regulation for intra-state generation tariff. MPERC determines tariff of intra-state generators, IPPs vide MYT orders.

Some highlights of generation tariff are given under:

- 2-part tariff structure comprising of Fixed Cost (FC) & Variable Cost (VC)
- SLDC computes & certifies plant availability factor (PAF) & scheduled energy on monthly basis for payment of FC & VC respectively to intra-state generators
- Monthly PAF computation is linked to DC similar to central sector generators

Intra-state ABT and Deviation settlement mechanism are operational since October 2009 which is applicable to all intra-state entities including DISCOMs, Open Access Customers and a few hydro stations. The scheduling & DSM for intra-state wind and solar generators is governed by the MPERC (Forecasting, Scheduling and Deviation Settlement) mechanism regulation 2018.

Metering

Intra-state ABT has provided for meters at each T-D (transmission-distribution) inter-face. Presently, 1081 inter-face energy meters are in place in the state. Deviation (DSM) and reactive energy (RE) charges for intra-state entities are computed based on main meter data. AMR system is in place for each interface (G-T, T-D and at SLDC which facilitates automatic meter-data downloading at SLDC. Missing meter data is retrieved using local meter reading instruments (MRI) & sent by mail upon intimation by SLDC on monthly basis. Procurement of check meters & meters capable of recording at 5-minute interval are being taken up with MPPTCL under a PSDF approved scheme.

Imbalance handling in real-time:

The SLDC real time operator has many tools for balancing and deviation control in real-time.

- Hydel and thermal generations of state owned Generating plants are regulated as per system requirement.
- Schedule from Inter-state generators (ISGS) is also regulated as per MOD if required.
- Under extreme contingencies or multiple outages in Generating units during the real time operation, after exhausting contingency reserves MP try to avail unrequisitioned surplus (URS) power from ISGS Power Stations of WR / NR / ER to adhere to grid discipline.
- MP always keeps some contingency reserve margin while preparing requisition on day ahead basis.

- While performing day ahead scheduling activities, if it is observed that there is no contingency margin for the next day, MPPMCL purchases adequate quantum of power through exchange to ensure availability of contingency margin.
- During the lean demand period, sudden drop in demand due to weather conditions or to absorb sudden rise in RE generation, grid discipline is mostly maintained by regulating hydro generation as an immediate measure.
- Subsequently schedule in state generating stations, ISGS and IPP Generating stations is revised as per MOD stack according to the requirement of the grid and hydel generation is again brought back to normal levels.
- Most of the hydro generators are out of the ambit of ABT & MOD. SLDC-MP dispatches hydro based on grid conditions. Renewable generation is treated as must run & their variability is handled by dispatching reserve margin available in hydro units.
- Since 2013 there is no load shedding in MP, therefore, load shedding option has not been required and not being exercised by system operator.

Intra-state deviation pool: Till December 2018 the pool was of a non-zero sum (surplus) type pool similar to the regional DSM pool. In January 2019, SLDC, MP has filed a petition before the Hon'ble MPERC wherein a zero-balance pool is proposed.

Key success factors for implementation of ancillary services

With the foregoing back ground the keys success factors for implementation of ancillary services in the state are summarized below:

Adequate Generation Capacity

Madhya Pradesh being a power surplus state, have adequate generation capacity at both thermal as well as hydel units. In view of sufficient thermal generation capacity SLDC-MP always have a scope to optimize the generation according to the MOD stack. After day ahead scheduling there is always chance to optimize the scheduling during intra-day operations. Based on the prevailing conditions during the real time operation rescheduling & redispatch can be initiated by SLDC to bring in further economy.

Thus, a framework of ancillary services for state of MP shall definitely be beneficial to both generators and beneficiaries to optimally dispatch the available generation & reserve capacity.

Multipart Tariff structure

The intra-state generation tariff has a multipart structure comprising of fixed cost component linked to plant availability & energy charge component linked to scheduled energy. Summary of Intrastate generating stations having two-part tariff and whose tariff for the entire capacity is determined/adopted by the SERC.

Table 18:MP State Generators with two-part tariff (2019)

S.N	Name of Station	n x MW	MW	FC (Rs/kwh)	VC (Rs/kwh)
1	Amarkantak (ATPS)	1X210	210	1.49	1.77
2	Satpura Ph. 2&3 (STPS_II&III)	1x200 3X210	830	0.83	2.78
3	Satpura Ph. 4 (STPS_IV)	2X250	500	2.04	2.33
4	Sanjay Gandhi 1&2 (SGTPS_I&II)	4X210	840	0.84	2.08
5	Sanjay Gandhi 3 (SGTPS_III)	1X500	500	1.15	1.91
6	Singaji 1 (SSTPS_I)	2X600	1200	1.54	2.84
7	Singaji 2 (SSTPS_II)	2X660	1320	1.42	2.68
Total			**5400**		

Norm for Technical minimum generation

MPERC has mandated for Technical minimum as 55% of MCR for intra-state generators also compensation for RSD and part-load operation of state generators.

Availability of URS power

There exists significant scope for dispatching the incidental reserves in the form of un-requisitioned surplus (URS) power in intra-state generators. The typical URS power availability at Intra-state generators for atypical day in summer/winter/monsoon season is given under.

Presently, there is no provision for dispatching URS power available in intra-state generators.

Pilot Optimization exercise with Excel Solver

Based on the FOR sub-group deliberation it was appreciated by the MP SLDC team that a scientific approach based on algorithmic solutions is desirable for reserve computation & monitoring and optimal dispatch thereof. Accordingly, a pilot exercise on constrained optimization technique was carried out by SLDC Madhya Pradesh to optimize the total production cost for a given sets of load-generation scenarios. The formulation used for optimization for a representative time block using MS excel solver is as given under:

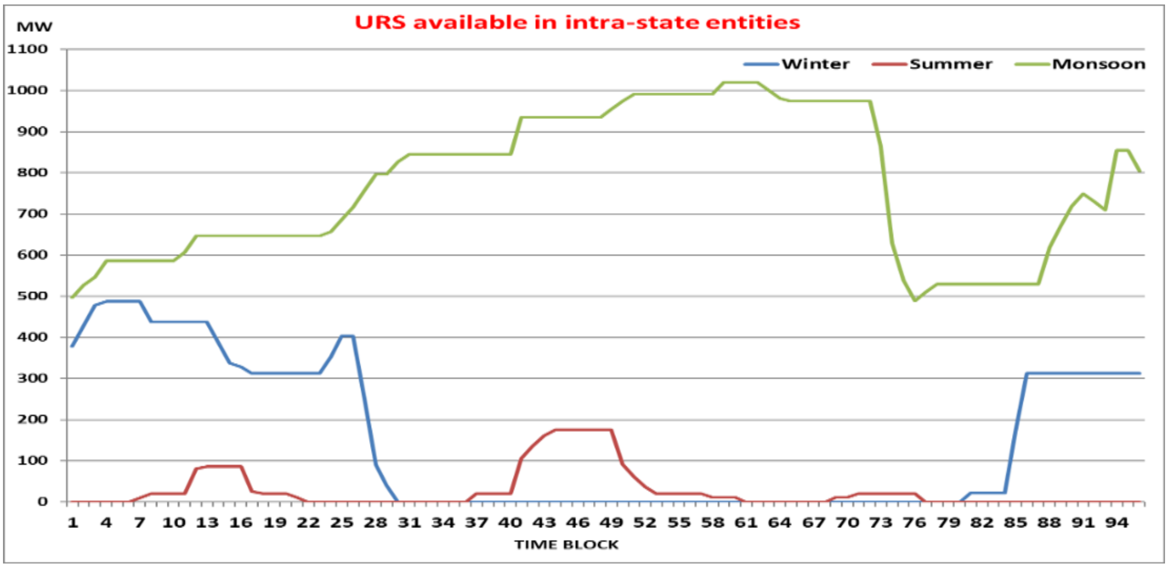


Figure 28: URS power in intra-state generators in MP for a typical day

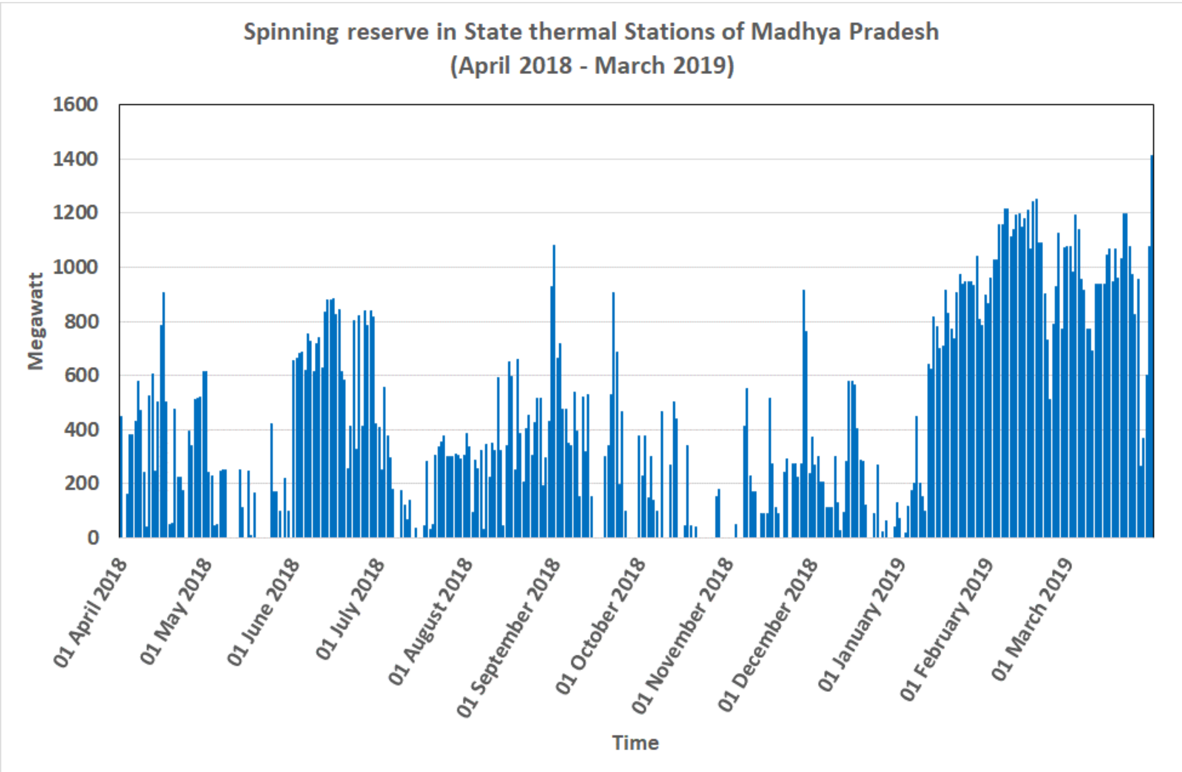


Figure 29:Spinning reserves in MP thermal stations

Input Data for each generator (for a time block):

(1) Declared capability in MW
(2) Declared capability on-bar (in MW)
(3) Schedule in MW
(4) Pmax = On bar installed capacity – Normative Auxiliary Consumption (in MW)
(5) Pmin = Technical Minimum generation (in MW)
(6) Variable charge (VC) in Rs/Kwh
(7) Ramp-Up rate in (%age of on-bar Capacity) per minute
(8) Ramp-down rate in (%age of on-bar Capacity) per minute

Derivable parameters for the generator (for a time block)

(1) Regulation Up-reserve = On bar installed capacity – Schedule (fig. in MW)
(2) Regulation Down-reserve = Schedule – Technical Minimum (fig. in MW)
(3) Cold reserve = DC – DC on bar …. (in MW)
(4) Hot spinning reserve = DC on bar – Schedule ….(in MW)
(5) Dispatchable reserve = Minimum of (Hot spinning reserve & Regulation Up Reserve)

Formulation of the Optimization Problem

- To minimize the Objective Function: $\sum \boldsymbol{Schedule} * \boldsymbol{VC} = \boldsymbol{Minimum}$
- Equality Constraint(s): ***Total schedule = Total demand of the state + Reserve***
- Inequality constraint(s): ***Pmin ≤ Station schedule ≤ Pmax;***
- Decision Variables: Schedule of each power plant to be despatched

Summary of the scenarios studied

Seven different system scenarios were studied by running the solver module for a single representative time block, based on above formulation for the state. The results are summarized under at table-

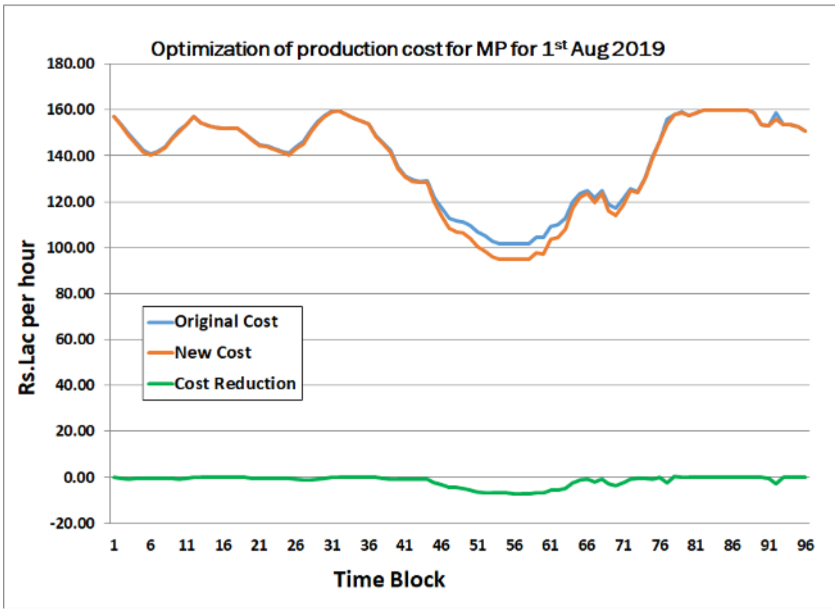
Table 19:Optimization Results for MP for different scenarios (for one time block in Jun 2019)

Senario	Total Production Cost in Rs		Avg. per unit cost		SMP	Up Reserve MW		Down Reserve MW	
	Pre-Optimized	Optimized	Pre-Optimized	Optimized	in Rs/unit	Apparent	Ramp Limited	Apparent	Ramp Limited
Morning Max demand	159.2	157.89	2.12	2.1	3.93	289	106	4510	2328
Morning Min demand	104.8	102.59	1.78	1.74	2.57	1887	794	3256	1798
Evening Demand (Max)	152.01	152.01	2.04	2.04	5.92	0	0	4432	2496
Evening Demand (Min)	103.45	99.89	1.78	1.72	2.57	1846	662	3180	1848
Max Surrender	82.84	80.56	1.77	1.72	1.76	3271	1312	1689	1173
Min. surrender	146.9	146.9	1.98	1.98	5.92	0	0	4773	2352
Maximum RE	86.38	84.19	1.76	1.72	1.77	3074	1243	1897	1273

Going further ahead, SLDC MP ran the optimization module all 96 blocks of a day. Due to limitations of the Excel solver software, the results of one block were considered as input to the next block in this sequential run of optimization. Based on this learning, it was decided to run simultaneous multiperiod optimization for all 96 blocks in one shot followed by continuous running in subsequent time blocks so as to take it to the next higher level for full-fledged implementation by SLDC. For further scaling up the need was felt for more efficient professional optimization software viz. the General Algebraic Modelling System

Observation & Inferences from the optimization exercise

- The optimization exercise gave vital decision tools viz. (1) plant wise optimum schedule, (2) system marginal price, (3) Up reserve (4) Down Reserve (5) Ramp limited reserves for a given time block
- Significant saving was seen in terms of net production cost and average per unit generation cost for all cases barring two scenarios viz. maximum evening demand and minimum central sector share surrender in a day.
- Apparently, these are the cases where there are very few chances of improvement as full on bar power was scheduled in both the cases.
- While running optimization sequentially for all 96 blocks of a day (01st Aug 2019), total cost benefit observed was to the tune of Rs. 1 crore 52 lacs.



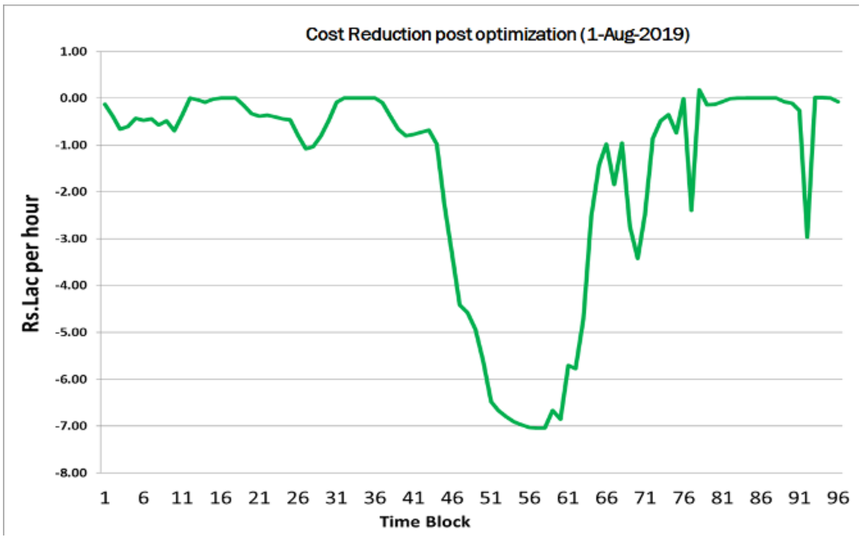


Figure 30: Production cost reduction post optimization exercise for MP for 1-Aug-19

Other generic inferences:

- Optimization tools could be used for day-ahead purchase decisions, ancillary despatch, economic despatch, estimation of reserve carrying cost.
- The optimization results could be converted into graphs for comprehension
- Database is required to save various scenarios and their results
- Following steps would be involved for running the Solver model: (1) *fetch data from the scheduling Software > (2) Run Solver Model > (3) Push the results back to the scheduling s/w;*
- Reliability of communication system is critical for continuous operation of the optimization program
- Dispatchable reserves is limited by ramping constraints, hence reserves need to be distributed over multiple units. Having more units on bar helps in improving the despatchable reserves volume.
- For realistic results, the must run stations (wind/solar/run-of-the river hydro) and must take (STOA) contracts could be kept out of optimization module with formulation Pmax = Pmin
- Net load forecast to be considered instead of demand forecast for realistic results
- Transmission constraints need to be considered in the optimization model
- Operationalized dispatch, assessment of reserves & its dispatch through ancillary services shall pave way for co-optimization of energy & ancillary.

Suggested actions for implementation of intrastate ancillary services:

Based on the learning from the above optimization exercise & deliberations in the FOR subgroup the following action plan is suggested for rolling out intra-state ancillary services

(a) A mandate from MPERC on the following aspects would be necessary to implement reserves framework and the reserve regulation ancillary services in MP:

- Notification of Technical minimum generation level
- Notification of ramping capability norms for generators
- Notification of methodology for computation of Variable Charges
- Notification of spinning reserves to be maintained at State level
- Method for assessment & monitoring of reserves by the SLDC
- Classification of the reserve as cold reserve, hot spinning reserve, fast/slow reserve, ramp limited reserve, dispatchable reserve etc.to bring more clarity.
- Notification of Regulations for intra-state ancillary services to facilitate despatch tertiary reserve
- Regulation for implementation of secondary reserves through AGC
- Amendment to intra- state open access regulations in line with the CERC inter-state open access regulations.

(b) Technology upgradation for seam-less integration of the software for reserves monitoring& ancillary services dispatch with the existing scheduling soft ware at SLDC & RLDC;

(c) Capacity building programs for SLDC personnel for end-to-end implementation of the reserves and ancillary services framework within the state.

Annex-VII: Pilot Project in Maharashtra

Brief profile of Maharashtra power system

As on October 2019, the state of Maharashtra has an installed generation capacity of 43717 MW (source: www.cea.nic.in) including state generation, independent power producers (IPPs) in the state and the state's share in central sector generation and jointly owned interstate generators. Out of the total generation capacity (~44 GW), 61% (27 GW) is coal-based generation, 21% (9.3 GW) is renewable energy-based (RE) generation, 8% (3.5 GW) is gas based generation and rest 8% (3.3 GW) is from hydro generation. In terms of annual energy generation in MUs for 2018-19, 61% of the generation energy came from intra state thermal (coal+gas) units, 30% from central sector units, 5% from wind, 3% from hydro and 1% from solar units.

The state demand follows a seasonal pattern wherein the peak demand (~ 23-24 GW) season typically falls in winter (October-December for rabi load) summer (April-May) where-as lean demand is registered in the monsoon season (July-September). Typically, the state demand undergoes a diurnal variation (i.e. difference between intra-day max. and min. demands) of 3000-4000 MW during winter and summer and 1000-2000 MW during the monsoon. A maximum state demand ramp of ~ 250-300 MW per block has been observed during onset of morning peak. Daily energy consumption varies between 400-430 MUs in lean demand period to 500-520 MUs during peak demand period.

With an installed renewable generation capacity of 9.3 GW Maharashtra is considered a renewable rich state which has so far witnessed a maximum RE penetration of 26% in terms of %age of instantaneous state generation and 14% in terms of daily energy consumption (MUs) on 13.06.18. RE generation contributes to 6% of net annual energy consumption by the state. Intra-day wind generation variation (Max-Min) stood at 1366 MW on 04.07.18 which witnessed maximum wind generation (3157 MW) in the state. Typically, the daily wind generation pattern follows the demand pattern during July - December where as the wind generation follows a reverse pattern to demand during rest of the of the period (viz. Jan to March).

Demand Forecasting

Demand forecasting is done by SLDC Maharashtra in line with the grid code. Maharashtra Electricity Regulatory Commission (Forecasting, Scheduling and Deviation Settlement for Solar and Wind Generation) Regulations, 2018 stipulates norms for forecasting of intra-state renewable (wind and solar) generation.

Scheduling

Maharashtra-SLDC computes schedule for the intra-state entities. As on August 2019 the different category of intra-state entities scheduled by SLDC Maharashtra are given below at Table-1.

Table 20: Entities scheduled by SLDC Maharashtra

S No	Category	Number
1	Distribution Licensees	9
2	Generating Companies	8*
	Total	**17**

Table 21: Discoms & Generating Companies scheduled by SLDC Maharashtra

SN	Distribution Licensees	Generating Companies
1	MSEDCL	MSPGCL (State owned Genco)
2	Tata Power Distribution Ltd	Adani Power Maharashtra Ltd.
3	Adani Distribution (Mumbai)	Adani Power (Dahanu)
4	BEST Mumbai	Tata Power Co. Ltd Mumbai
5	Indian Railway (Deemed Discom)	JSWEL Ratnagiri
6	Mindspace Business Park	Ratan India (Amravati)
7	Gigaplex Electricity	Dhariwal Infrastructure Ltd (stg-1)
8	Nidar Utilities Panvel Pvt Ltd	-
9	KRC Infrastructure Pvt Ltd	-

A new scheduling software (MiDss) developed by M/s. PRDC Bangalore is in operation since 01.01.2019. Different categories of scheduling contracts coordinated by SLDC, Maharashtra for a typical day are summarized below.

Table 22: Contracts scheduled by SLDC Maharashtra (2019)

S No.	Type	No.	MW
1	Long / Medium term PPA - intrastate	27	8171
2	Long / Medium term PPA – intrastate (Hydro/RE)	114	4369
3	Short-term bilateral intrastate (Typical in a day)	40	570
4	Long / Medium term PPA -interstate	24	7100
5	Long / Medium term PPA – interstate (Hydro/RE)	5	270
6	Short term bilateral contracts-interstate (Typical in a day)	22	1537
7	Short term contracts-PX (Typical in a day)	26	733
	Total	**258**	**22750**

Scheduling Time line

Day ahead & real time scheduling coordination is done by SLDC with intra-state entities and WRLDC as per a specified time line given in the grid code. The following table summarizes the different time lines followed for scheduling activities at SLDC.

Table 23: Scheduling Time line (SLDC Maharashtra)

Time	Description	Coordinated by
09:00	Availability of ISGS Station wise ex-power plant MW and MWh capabilities foreseen for the next Day	WRLDC (available on website)
10:00	Consent for ISGS capacities by beneficiaries	Intra-state Beneficiary
10:00	Buyers to furnish MSLDC with time block wise drawal schedule for next day	Buyers
10:00	Open Access Consumers furnish time block wise drawal schedule for next day	Open access consumers
12:00	Target despatch schedule for seller and target drawal schedule for buyers.	MSLDC
14:00	Revised demand forecast and availability forecast	Beneficiaries/Generators
15:00	ISGS drawal schedule of beneficiaries	MSLDC
17:00	"Net drawal schedule" of the State in MW and MWh for the next day	WRLDC (available on website)
18:00	IEX power purchases/sales and revised drawal schedule for next day against bilateral power and IPP requisition they have contracted in short term and long-term basis.	Buyers & MSLDC coordinate & incorporate
22:30	Revised ISGS drawal schedule by beneficiaries	MSLDC & WRLDC
23:00	Final load generation balance	MSLDC (through website)
23:00	Final despatch schedules for sellers and drawal schedules for buyers	MSLDC

Merit Order Dispatch (MOD):

Merit Order Despatch is the least cost approach to meet demand from the contracted capacity of the respective Distribution Licensee. MOD module is run day-ahead basis by SLDC based on

VC. A monthly 'Merit Order Stack' is prepared on monthly basis based on the Variable charge (energy charge) using the following input data as per the MERC guidelines (order in Case No 42 of 2006).

a) Intra-state generators having long term contract with distribution licensees whose their tariff is determined by MERC submit the variable charge (VC) to SLDC by 10th of every month.
b) Distribution licensees submit variable cost of power purchase from IPPs /ISGS as per PPA.
c) Intra-state STOA transaction (50MW and Above) are considered in merit order stack and are subjected to curtailment as per merit order up to 70 % on the basis of price of transaction [as per decision of state power committee (MSPC)].
d) Central sector generating station variable cost is submitted by MSEDCL and incorporated in state merit order stack.
e) Merit order stack gets effective from 00:00Hrs of 12th day of every month to 11th day of next month.
f) Revision is allowed in MOD Stack in same month for reasons such as change in law, change in rate due to change in POC loss/state transmission loss, addition or expiry of short-term bilateral contract considered in MOD, COD of intra-state generating stations or Central sector generating station etc.

Generation Tariff Structure

Maharashtra Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2019 stipulates norms for intra-state generation tariff. MERC determines tariff of intra-state generators vide MYT orders. Some highlights of generation tariff are given under:

- 2-part tariff structure comprising of Fixed Cost (FC) & Variable Cost (VC)
- SLDC computes & certifies plant availability (PAF), plant load factor(PLF), scheduled energy and actual energy for all intra-state generators
- Monthly PAF computation is linked to DC similar to central sector generators

Imbalance handling by SLDC

As per the MERC order in case 42/2006 dated 17.05.2007, intra-state imbalance settlement mechanism (Final Balancing & Settlement Mechanism - FBSM) was implemented w.e.f. August 2011 which. The FBSM follows a 15-minute settlement period & weekly settlement cycle. Imbalance/Deviation charge is calculated post facto based on weighted average system marginal price (SMP). The deviation charges are not linked to frequency.

- 9 Discoms (4 Distribution licensees + 5 Deemed distribution licensees) and 12 merchant generators fall under FBSM mechanism.
- Generators with long term contract with DISCOMs are not subjected to imbalance pool charges.

- Entire state generation and aggregated demand forecast of DISCOMs are balanced by operating centralized (State wide) MOD.

Maharashtra Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2019 was notified on 01.03.19 with provisions similar to the CERC regulations on deviation settlement. This is expected to be effective from 1.4.2020. The scheduling & DSM for intra-state wind and solar generators is governed by the MERC (Forecasting, Scheduling and Deviation Settlement of wind & solar generators) regulation 2018.

Imbalance handling in real-time:

Imbalance handling in real time operation is done by SLDC as under:

- During low demand conditions, costlier intra-state generators are backed down as per implemented MOD stack so that central sector drawal is maintained within permissible limits as per IEGC.
- Available hydro generation in the state are utilized as per system requirement.
- Available URS power from ISGS is utilized as per system requirement.

Metering

1118 special energy meters (ABT meters) capable of recording energy at every 15 minutes are used for weekly settlement of deviations from schedules. Special Energy Meters (ABT meters) with 15 min recoding facility are used at all interfaces (boundaries) for the SPPs (state pool participants) including all DISCOMs except MSEDCL in view of large number of customers. For MSEDCL the interchange is calculated based on rest of the meters.

Intra-state deviation pool

The state pool is a zero-balance pool by design. SLDC prepares weekly deviation account.

Typical deviation volume for 4 weeks in Jan 2019 are given under for reference.

Deviation volume from 01 to 28 Jan 19						
Dates	**Drawl (Mus)**	**Schedule (Mus)**	**Deviation (Mus)**	**UI-charges (Rs lakh)**	**Cap UI (Rs. In Lakhs)**	**Addl. UI (Rs. In Lakhs)**
01 Jan-19 to 07 Jan-19	601.51	604.62	3.11	-102.89	119.74	115.36
08 Jan-19 to 14 Jan-19	726.68	730.17	3.50	-23.25	74.45	127.58
15 Jan-19 to 21 Jan-19	851.89	852.83	0.94	-25.21	40.78	58.50
22 Jan-19 to 28 Jan-19	808.62	812.90	4.29	-33.39	73.14	149.00
Total	**2988.70**	**3000.53**	**11.84**	**-184.74**	**308.11**	**450.43**

Key success factors for implementation of ancillary services

With the foregoing back ground the keys success factors for implementation of ancillary services in the state are summarized below:

Adequate Generation capacity & diversity

A framework of ancillary services shall be beneficial to both generators and beneficiaries to optimally dispatch the available generation & reserve capacity in view of the following factors as to generation adequacy & diversity in generation technology.

1. Maharashtra has adequate generation capacity including thermal, gas, hydro and renewables.
2. The state has allocation in all major inter-state generators of Western Region.
3. The state has a significant number of merchant generators
4. Similarly, it is a renewable rich state with high penetration (~20-25%) of variable renewable generation which are must run stations & hence need to be absorbed.

Thus, the SLDC has a scope for optimizing the generation dispatch as per requirements of reliability & economy (w.r.t.MOD stack). Based on the prevailing real time conditions rescheduling & redispatch can be initiated by SLDC to bring in further economy. Thus, a framework of ancillary services shall help in optimally dispatching the available generation & reserve capacity for handling imbalance and facilitating absorption of renewable generation.

Multipart Tariff structure

The intra-state generation tariff has a multipart structure comprising of fixed cost component linked to plant availability & energy charge component linked to scheduled energy. Summary of Intrastate generating stations having two-part tariff and whose tariff for the entire capacity is determined/adopted by the SERC.

Table 24: Maharashtra State Generators with two-part tariff (2019)

Name of Generating Station	Owner	No of Units x MW Size	TOTAL (MW)	Fixed Cost (Rs/Unit)	Variable rates (Rs/kWh)
NASIK U-3,4 & 5	MSPGCL	3*210	630	0.9500	4.0981
KORADI U-6 & 7	MSPGCL	2*210	420	0.9500	4.0180
BHUSAWAL U-3	MSPGCL	1*210	210	0.8400	3.7883
VIPL U-1 & 2	VIPL	2*300	600	2.2200	3.7193
DTPS U-1 & 2	DTPS	2*250	500	0.8700	3.6998
TPC U-5	TATA	1*500	500	1.3800	3.6974
TPC U-8	TATA	1*250	250	1.5600	3.6066

KHAPERKHEDA U- 1 TO 4	MSPGCL	4*210	840	0.6900	3.5770
PARAS U-3 & 4	MSPGCL	2*250	500	1.3600	3.4333
PARALI U-6 &7	MSPGCL	2*250	500	1.3300	3.3821
PARALI U-8	MSPGCL	1*250	250	1.6300	3.3515
RATTANINDIA U-1 TO 5 (PPA-1200 MW)	IPP	5*270	1200	1.1000	3.3375
CHANDRAPUR U-3 TO 7	MSPGCL	2*210 & 3*500	1920	0.5700	3.2967
CHANDRAPUR U-8 & 9	MSPGCL	2*500	1000	2.9000	3.2063
BHUSAWAL U-4 & 5	MSPGCL	2*500	1000	1.4900	3.1883
KHAPERKHEDA U-5	MSPGCL	1*500	500	1.3800	3.1511
KORADI U-8 ,9 &10	MSPGCL	3*660	1980	2.4300	2.9286
TPC U-7 (APM)	TATA	1*180	180	2.51	2.8931
ADANI (TIRODA 440 MW PPA) U 1,4 & 5	IPP	440	Coal	1.366	2.7779
ADANI ,TIRODA U-1, 4 & 5 (PPA-1200 MW and 125 MW)	IPP	1325	Coal	1.326	2.7179
ADANI ,TIRODA U-2&3 (1320 PPA)	IPP	1320	1325	1.1130	2.7179
JSW-Ratnagiri U-1	IPP	1*300	300	0.8000	2.5523

Evolving Regulatory framework for reserves

The intra-state regulatory framework is gradually evolving to set aside a specific margin towards spinning reserve. The MERC has notified a MOD guideline (in 08.03.19) that envisages a spinning reserve equivalent to highest thermal size generator in state (i.e. 660 MW at present) to be maintained at state level. Relevant extracts are given under:

"7.2……………………………………………….In order to meet system contingencies MSEDCL may keep hydro capacity equivalent to the capacity of largest thermal unit as a spinning reserve. MSEDCL to ensure that the hydro capacity to be kept as spinning reserve should be a mix of hydro units from different generating companies (….) instead if hydro units from a single generating station or hydro units of one generating company."

Thus, Maharashtra is getting gradually oriented for adopting a full-fledged framework on reserves & ancillary services.

Norm for Technical minimum generation

The MOD guidelines of MERC dated 08.03.2019 has provisions for Technical minimum as 55% of MCR for intra-state thermal generators. Similarly, it mandates for preparation of a detailed procedure by SLDC for compensation for RSD and part-load operation of state generators

URS power

Unscheduled power of intra-state generator is utilized for its contracted buyer only. Presently, there is no provision for dispatching un-requisitioned surplus (URS) power available in intra-state generators.

Pilot Optimization exercise with Excel Solver

Based on the FOR sub-group deliberation it was appreciated by the SLDC Maharashtra team carried out, a pilot exercise on constrained optimization technique to optimize the total production cost for a given sets of load-generation scenarios. The formulation used for optimization for a representative time block using MS excel solver is as given under:

Input Data for each generator (for a time block):

- Declared capability in MW
- Declared capability on-bar (in MW)
- Schedule in MW
- Pmax = On bar installed capacity – Normative Auxiliary Consumption (in MW)
- Pmin = Technical Minimum generation (in MW)
- Variable charge (VC) in Rs/Kwh
- Ramp-Up rate in (%age of on-bar Capacity) per minute
- Ramp-down rate in (%age of on-bar Capacity) per minute

Derivable parameters for the generator (for a time block)

- Regulation Up-reserve = On bar installed capacity – Schedule (fig. in MW)
- Regulation Down-reserve = Schedule – Technical Minimum (fig. in MW)
- Cold reserve = DC – DC on bar …. (in MW)
- Hot spinning reserve = DC on bar – Schedule ….(in MW)
- Dispatchable reserve = Minimum of (Hot spinning reserve & Regulation Up Reserve)

Formulation of the Optimization Problem

- To minimize the Objective Function: $\sum \boldsymbol{Schedule * VC = Minimum}$
- Equality Constraint(s): ***Total schedule = Total demand of the state + Reserve***
- Inequality constraint(s): ***Pmin ≤ Station schedule ≤ Pmax;***
- Decision Variables: Schedule of each power plant to be despatched

Summary of the scenarios studied

Seven different system scenarios were studied by running the solver module for a single representative time block, based on above formulation for the state. The results are summarized under at table-

Table 25:Optimization Results for Maharashtra (one time block for each case in Jul 2019)

Scenarios	Total production cost in Rs lakh		Average Production cost (Rs/Unit)		System Marginal Price (Rs/Unit)	Up reserve available (MW)		Down reserve available (MW)	
	Pre-Optimized	Optimized	Pre-Optimized	Optimized		Apprent	Ramp limited	Apprent	Ramp limited
Case 1:Maximum Demand	515	484	2.54	2.49	3.29	871	300	9043	1082
Case 2: Minimum Demand	366	320	2.45	2.27	2.81	2339	382	6592	526
Case 3: Maximum Wind	375	350	2.47	2.31	2.96	1609	90	7347	570
Case 4: Minimum Wind	361	349	2.3	2.26	3.69	307	134	7468	809
Case 5: Maximum Surrender	284	276	2.54	2.51	2.52	5479	759	3452	149
Case 6: Minimum Surrender	507	483	2.59	2.41	3	2871	721	7043	661

For further scaling up the need was felt for more efficient professional optimization software viz. the General Algebraic Modelling System. The observations and inferences from the optimization exercise are as under:

- After optimization total production cost and average production cost in Rs/Unit have reduced.
- Up reserve margin and down reserve margin along with ramp limitation is available for each block to operator for any real time contingencies and operation.
- Allowable increase and allowable decrease in demand figures so that SMP will not get change is readily available from the solver output.
- Using this tool economic or optimal despatch/schedule can be given to generators.
- Optimization tools could be used for day-ahead purchase decisions, ancillary despatch, economic despatch, estimation of reserve carrying cost.
- The optimization results could be converted into graphs for comprehension
- Database is required to save various scenarios and their results
- Following steps would be involved for running the Solver model:
    - (1) *fetch data from the scheduling Software*
    - *(2) Run Solver Model*
    - *(3) Push the results back to the scheduling s/w*
- Reliability of communication system is critical for continuous operation of the optimization program

- Dispatchable reserves is limited by ramping constraints, hence reserves need to be distributed over multiple units. Having more units on bar helps in improving the despatchable reserves volume.
- For realistic results, the must run stations (wind/solar/run-of-the river hydro) and must take (STOA) contracts could be kept out of optimization module with formulation Pmax = Pmin
- Net load forecast to be considered instead of demand forecast for realistic results
- Transmission constraints need to be considered in the optimization model
- Operationalized dispatch, assessment of reserves & its dispatch through ancillary services shall pave way for co-optimization of energy & ancillary.

Suggested actions for implementation of intrastate ancillary services:

Based on the learning from the above optimization exercise & deliberations in the FOR subgroup the following action plan is suggested for rolling out intra-state ancillary services

(a) A mandate from MERC on the following aspects would facilitate implementation of reserves framework and the ancillary services in Maharashtra given the fact that MERC has already come out with a guideline for technical minimum (55%) and spinning reserves in March 2019.

- Notification of ramping capability norms for generators
- Notification of methodology for computation of Variable Charges
- Method for assessment & monitoring of reserves by the SLDC
- Classification of the reserve as cold reserve, hot spinning reserve, fast/slow reserve, ramp limited reserve, dispatchable reserve etc.to bring more clarity.
- Notification of Regulations for intra-state ancillary services to facilitate dispatch tertiary reserve.
- Approximately 5% margins in thermal generating station of costlier station would be desirable. For fast response reserve margins are to be kept in hydro generators in the state.

(b) Technology upgradation for seam-less integration of the software for reserves monitoring & ancillary services dispatch with the existing scheduling soft ware at SLDC & RLDC;

(c) Capacity building programs for SLDC personnel for end-to-end implementation of the reserves and ancillary services framework within the state.

Annex-VIII: Pilot Project in Gujarat

Brief power profile of the State

As on October 2019, Gujarat has an installed generation capacity of 34545 MW (source: www.cea.nic.in) including state generation, independent power producers (IPPs) in the state and the state's share in central sector generation and jointly owned interstate generators. Out of the total generation capacity (~35 GW), 48% (16 GW) is coal-based generation, 29% (10 GW) renewable energy-based (RE) generation & 19% (6.5 GW) is gas based generation. In terms of annual energy generation in MUs for 2018-19, out of the total state consumption of 122 billion units (BUs), 47% (57 BUs) came from intra-state thermal (coal+gas+nuclear) units, 34% (42 BUs) from central sector generation, 11% (14 BUs) from renewable generation (Wind & Solar), 8% (9 BU) from hydro generation.

The state demand follows a seasonal pattern wherein the peak demand (~ 16-17 GW) season typically falls in winter (Oct-Dec) & summer (Apr-May) where-as lean demand (~ 12 GW) is registered in the monsoon season (Jul-Sep). Typically, the state demand undergoes a diurnal variation (i.e. difference between intra-day max. and min. demands) of the order of 6000-MW during winter and 2000-3000 MW during the summer. Typically, state demand ramp of 100-150 MW per time block takes place during onset of morning peak in winter (Oct-Dec). Average daily energy consumption varies between 330 million units (Mus) in lean demand period and 390 MUs during peak demand period.

Gujrat is a renewable rich state in WR with an installed renewable generation capacity of 13.7 GW (as of October 2019). The state has so far witnessed a maximum RE penetration of 40% in terms of %age of instantaneous state generation (in MW) in July 2018. Similarly, max. RE penetration in terms of %age of total daily energy consumption stood at 33% in July 2018. RE generation contributes to 11% of net annual energy consumption by the state. Maximum intra-day wind generation variation (Max-Min) of 1000-1200 MW has been observed in high wind season viz. June-July. Typically, the daily wind generation pattern to an extent follows the demand pattern during April to September where as the wind generation follows a reverse pattern to demand during the of the period (October to March).

Forecasting Scheduling & Deviation Settlement

Forecasting

Forecasting is done as per the state grid code & the GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019.

Scheduling

Intra state ABT is implemented in Gujarat since 2010. As on August 2019, the different entities whose scheduling is coordinated by SLDC Gujarat are given below at Table-1.

Table 26: Entities scheduled by SLDC Gujarat

S No	Category	Number
1	Distribution Licensees	9
2	Intra-State Generators	18
3	Inter-State Generators	27
4	Solar Power stations	116
5	Wind Power stations	79
6	Independent Power Producers	16
	Total	**265**

SLDC is the nodal agency for scheduling of intra-state short term open access (STOA) transactions. In addition to STOA all the LTA, MTOA and wheeling contract are scheduled by SLDC. Different categories of contracts handled by SLDC Gujarat is shown below at Table-2:

Table 27: Contracts scheduled by SLDC Gujarat (2019)

S.N.	Contract Type	Number
1	Long Term Inter state	20
2	Long Term Interstate (RE)	1
3	STOA Interstate (01/10/19)	256
4	Long Term Intrastate	27
5	Medium term Intrastate	107
6	STOA Intrastate (1/10/19)	11
	Total	**422**

Scheduling Time line

The scheduling procedure followed by SLDC Gujarat is very similar with that given in IEGC scheduling code. The time line for different key activities in day-ahead scheduling is given under at Table-3.

By 9 to10 hours all state generators upload their DC through on line scheduling web portal of SLDC. After checking the input figures, the entitlement for the DISCOMs and MTOA contract details are published. By14.00 hours the requisition is submitted by the discoms and MTOA customer. By16.00 hours, collective transaction cleared report is received by SLDC. Based on all these and applying merit order dispatch the original schedule (version R0) for next day is published by 18.00 hours. The merit order dispatch (MOD) is prepared based on variable cost of the generators. The real time balancing is done by backing down or peaking up of thermal power stations. In case of contingency gas turbine generators are taken on bar and contingency power purchase is also explored as per requirement.

Table 28: Scheduling Time line (SLDC Gujarat)

D-1 day (hh:mm)	Scheduling Activities on Day-ahead horizon
10:00	Capability declaration (DC) for next day by Intra-state generators/IPPs/Shared plants; ISGS entitlements taken from WRLDC website
14:00	Entitlement and MTOA contract details published by SLDC for state DISCOMs;
16:00	SLDC compiles the collective transactions cleared in the Power Exchanges.
18:00	SLDC Gujarat issues ex-PP injection schedule to generators & ex-STU periphery drawal schedule to DISCOMs (R0) after considering state MOD.

Generation Tariff: A multi-part tariff structure comprising of fixed charge & variable charge is in place for most of the intra-state generators.

Merit Order Dispatch (MOD): MOD stack is prepared by the holding Distribution Company (Gujarat Urja Vikas Nigam Ltd. - GUVNL) on behalf of the state DISCOMs (viz. Uttar Gujarat Vij Company Ltd. (UGVCL),Dakshin Gujarat Vij Company Ltd. (DGVCL), Madhya Gujarat Vij Company Ltd.(MGVCL),Paschim Gujarat Vij Company Ltd. (PGVCL) based on VC of generators. A typical merit order based on VC as on 15.10.2019 is given under:

Table 29: Typical MOD stack of Gujarat Intra-state generators (15-Oct-2019)

S. No.	Power Station	Capacity (n*M)	FC (Rs./unit)	VC (in Rs/unit)
1	Ukai Hydro	4x75	Must run	0.17
2	ACB India Ltd	2x100	1.46	0.74
3	AKRIMOTA	2x125	0.79	1.33
4	GIPCL -MANGROL LIGNITE SLPP Expansion	2x125	1.53	1.44
5	GIPCL -MANGROL LIGNITE SLPP	2x125	0.73	1.44
6	ONGC - ANKLESHWAR	1x5	CPP (free power)	1.9
7	ONGC - HAZIRA	1x5		1.9
8	ONGC - HAZIRA	1x5		2.25
9	Dhuvaran CCPP-I & II(GSECL) on GAIL(APM)	2x107	0.72	2.45
10	BLTPS	2x250	2.63	2.6
11	KLTPS 4	1x75	1.95	2.66
12	Dhuvaran CCPP I & II on ONGC WO	2x107	0.72	2.71
13	KLTPS 1-3	3x75	1.5	2.85

S. No.	Power Station	Capacity (n*M)	FC (Rs./unit)	VC (in Rs/unit)
14	Adani Power Limited (Mundra) Unit-1-4 (1000 MW)	4x250	1.21	3.01
15	Essar Vadinar	2x500	1.09	3.02
16	Adani Power Limited (Mundra) Unit-1-4 (200 MW)	4x50 (add.)	1.21	3.06
17	GIPCL-I ON GAS - HVJ	2x37	0.34	3.18
18	UKAI - TPS- 6	1x500	1.69	3.24
19	SIKKA 3-4	2x250	1.58	3.25
20	GIPCL-I ON GAS - Gandhar	2x37	0.34	3.27
21	Utran-II (High Sea Sale)	1x375	0.98	3.59
22	GSEG, Expansion (High Sea Gas)	1x351	1.15	3.61
23	Dhuvaran CCPP-III (High Sea Sale)	1x376	1.11	3.61
24	GPPC (High Sea Sale)	2x351	0.76	3.61
25	UKAI - TPS 3-5	3x210	0.37	3.68
26	Dhuvaran CCPP-I & II (High Sea Sale)	2x107	0.72	3.8
27	GSEG Hazira (High Sea Gas)	2x78	0.46	3.9
28	WANAKBORI TPS # 7	1x210	0.6	4.07
29	GANDHINAGAR TPS #5	1x210	0.63	4.08
30	WANAKBORI TPS # 1-6	6x210	0.47	4.19
31	GANDHINAGAR TPS # 3,4	2x210	1.08	4.22
32	GSEG, Expansion (GSPC Spot Gas)	1x351	1.15	4.48
33	Utran-II (GSPC Spot Gas)	1x375	0.98	4.48
34	Dhuvaran CCPP-III (GSPC Spot Gas)	1x376	1.11	4.5
35	GPPC (GSPC Spot Gas)	2x351	0.76	4.5
36	Dhuvaran CCPP-I & II (GSPC Spot Gas)	2x107	0.72	4.74
37	GSEG, Hazira (GSPC Spot Gas)	2x78	0.46	4.84
38	GIPCL-I ON GSPC SPOT GAS	2x37	0.34	5.95
39	Dhuvaran CCPP-I & II (GAIL Spot Gas)	2x107	0.72	7.15
	Total	**13205**		

Private DISCOMs viz. Torrent (TAECO-Ahmedabad, TSECO-Surat, Dahej-SEZ) having long/medium term PPA with intra-state IPPs viz Sugen, Uno-Sugen, DGEN etc. submit their mutually agreed consolidated requisition which is incorporated in the schedule by SLDC Gujarat.

Imbalance handling by SLDC

Intra-state ABT and Deviation settlement mechanism are operational in Gujarat since 2010 which is applicable to all intra-state entities including DISCOMs and open access customers. The scheduling & DSM for intra-state wind and solar generators is governed by the Gujarat Electricity Regulatory Commission (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019.

SLDC Gujarat maintains deviation (DSM) accounts for all intrastate entities. It is a zero-sum account as per GERC (Deviation Settlement Mechanism) regulations.

Preparation of DSM accounts for the wind and solar Generators has since been commenced in Gujarat after notification of GERC (Forecasting, Scheduling, Deviation Settlement and related matters of Solar and Wind generation sources) Regulations, 2019. All wind and solar generators give their forecast and available capacity (AVC) and revise in real time as per GERC regulations. A summary of intra-state DSM account of Gujarat for four weeks of July 2019 are given under for reference.

Table 30: Gujarat Intra-state DSM account for July 2019

Week	Date (From / To)	Deviation energy (in MWH)	Deviation charge (in Rs)
14	01.07.19 TO 07.07.19	83336	82612477
15	08.07.19 TO 14.07.19	81796	104056770
16	15.07.19 TO 21.07.19	82142	135214739
17	22.07.19 TO 28.07.19	90625	91177680

Key success factors for implementation of ancillary services

The keys success factors for implementation of ancillary services in the state are summarized below:

Favorable Generation Mix & high RE penetration

Gujarat has adequate generation capacity including thermal, gas, hydro and renewables. The state has allocation in all major inter-state generators of Western Region. The state has a significant number of merchant generators (viz. 2x660 MW Adani Power Stage-II Mundra, 2x150 MW Bhadreswar Vidyut Pvt. Ltd. Kutchh). Gujarat has a considerable volume of gas-based merchant generation (viz. 630 MW CLPIPL-Gas station etc.) which can be dispatched under ancillary services. Similarly, it is a renewable rich state with high penetration (~30%) of variable renewable generation which are must run stations & hence need to be absorbed. Thus, the SLDC has a scope for optimizing the generation dispatch as per requirements of reliability & economy (w.r.t.MOD stack). Based on the prevailing real time conditions rescheduling & redispatch can be initiated by SLDC to bring in further economy. Thus, a framework of ancillary services shall help in optimally dispatching the available generation & reserve capacity for handling imbalance and facilitating absorption of renewable generation.

Multipart Tariff structure

The intra-state generation tariff has a multipart structure comprising of a fixed charge (FC) component linked to plant availability & a variable charge (VC) component linked to scheduled energy. Thus, two-part tariff structure along with intra-state ABT & DSM mechanisms provide a conducive framework for rolling out intra-state ancillary services.

Norm for Technical minimum generation

GERC is yet to give a mandate for Technical minimum for intra-state generators. However, the technical minimum is generally considered as 60-70% of MCR for thermal generators based on vintage & capacity.

Availability of URS power

There exists significant scope for dispatching the incidental reserves in the form of un-requisitioned surplus (URS) power in intra-state generators. Reserve monitoring in real time is done by SLDC operators through the web-based scheduling software. The URS power available in real time can be despatched by SLDC operator under a framework of ancillary services.

Pilot Optimization exercise with Excel Solver

Based on the FOR sub-group deliberation it was appreciated by the SLDC team that a scientific approach based on algorithmic solutions is desirable for reserve computation & monitoring and optimal dispatch thereof. Accordingly, a pilot exercise on constrained optimization technique was carried out by SLDC Gujarat to optimize the total production cost for a given sets of load-generation scenarios with help of an excel solver tool devised by NLDC team. The formulation used for optimization for a representative time block using MS excel solver is as given under:

Input Data for each generator (for a time block):

- Declared capability in MW
- Declared capability on-bar (in MW)
- Schedule in MW
- Pmax = On bar installed capacity – Normative Auxiliary Consumption (in MW)
- Pmin = Technical Minimum generation (in MW)
- Variable charge (VC) in Rs/Kwh
- Ramp-Up rate in (%age of on-bar Capacity) per minute
- Ramp-down rate in (%age of on-bar Capacity) per minute

Derivable parameters for the generator (for a time block)

- Regulation Up-reserve = On bar installed capacity – Schedule (fig. in MW)
- Regulation Down-reserve = Schedule – Technical Minimum (fig. in MW)
- Cold reserve = DC – DC on bar …. (in MW)
- Hot spinning reserve = DC on bar – Schedule ….(in MW)
- Dispatchable reserve = Minimum of (Hot spinning reserve & Regulation Up Reserve)

Formulation of the Optimization Problem

- To minimize the Objective Function: $\sum \boldsymbol{Schedule * VC = Minimum}$
- Equality Constraint(s): ***Total schedule = Total demand of the state + Reserve***
- Inequality constraint(s): ***Pmin ≤ Station schedule ≤ Pmax;***
- Decision Variables: Schedule of each power plant to be despatched

Summary of the scenarios studied

Five different scenarios were studied by SLDC Gujarat running the solver module for a single representative time block, based on above formulation for the state. Results are summarized at Table-7. As can be seen, there is potential for saving in most of the cases studied during the above optimization exercise. For further scaling up the need was felt for more efficient professional optimization software viz. the General Algebraic Modelling System with which the optimization can be run for all 96 blocks on continuous basis.

Table 31: Optimization Results for Gujarat for different scenarios (each case for one time block)

Scenarios		Total production cost in Rs lakh		Average Production cost (Rs/Unit)		System Marginal Price (Rs/Unit)	Up reserve available (MW)		Down reserve available (MW)	
Day	Block	Pre-Optimized	Optimized	Pre-Optimized	Optimized		Apprent	Ramp limited	Apprent	Ramp limited
20-Jun-19	89	347	340	2.97	2.94	1.99	66	N/A	216	N/A
21-Jul-19	61	400	392	3.16	3.11	3.67	11	N/A	228	N/A
21-Jul-19	80	321	318	2.94	2.94	3.67	14	N/A	112	N/A
22-Jul-19	21	411	387	3.17	3.11	3.33	54	N/A	145	N/A
22-Jul-19	61	386	386	3.15	3.13	3.84	44	N/A	126	N/A

The observation & inferences from the optimization exercise are as under.

- The optimization exercise gave vital decision tools viz. (1) plant wise optimum schedule, (2) system marginal price, (3) Up reserve (4) Down Reserve (5) Ramp limited reserves for a given time block
- The above optimization was done with demand of GUVNL (state owned DISCOMs) only (without considering the demands of other private DISCOMs). There is likelihood of more saving if the entire state demand with all DISCOMs is considered.
- Optimization tools can be used for day-ahead purchase decisions, economic despatch, ancillary despatch, estimation of reserve carrying cost.
- The optimization results can be converted into graphs for comprehension
- Database is required to save various scenarios and their results

- Necessary steps involved for running optimization module:
    - (1) *fetch data from the scheduling Software >*
    - *(2) Run Solver Model*
    - *(3) Push the results back to the scheduling s/w;*
- Reliability of communication system is critical for the optimization program
- Dispatchable reserves is limited by ramping constraints, hence reserves need to be distributed over multiple units.
- Having more units on bar helps in improving the despatchable reserves volume.
- For realistic results, the must run stations (wind/solar/run-of-the river hydro) and must take (STOA) contracts could be kept out of optimization module with formulation Pmax = Pmin
- Transmission constraints need to be considered in the optimization model

Suggested actions for implementation of intrastate ancillary services:

Based on the learning from the above optimization exercise & deliberations in the FOR subgroup the following action plan is suggested for rolling out intra-state ancillary services

a. A mandate from SERC on the following aspects would be necessary to implement reserves framework and the reserve regulation ancillary services in Gujarat:
    - Notification of Technical minimum generation level & gate closure
    - Notification of ramping capability norms for generators
    - Notification of methodology for computation of variable charge
    - Notification of spinning reserves to be maintained at State level
    - Method for assessment & monitoring of reserves by the SLDC
    - Classification of the reserve as cold reserve, hot spinning reserve, fast/slow reserve, ramp limited reserve, dispatchable reserve etc.to bring more clarity.
    - Notification of Regulations for intra-state ancillary services to facilitate dispatch of tertiary reserves

b. Infrastructure for seam-less integration of the software for reserves monitoring & ancillary services dispatch with the existing scheduling software at SLDC & RLDC;

c. Capacity building programs for SLDC personnel for end-to-end implementation of the reserves and ancillary services framework within the state.

Draft Model Regulation on Intra-State Essential Reliability Services

No. XX / XX /20XX　　　　　　　　　　　　　　　　　　　　　　　Dated: DD.MM.20XX

In exercise of the powers conferred under sections 42, 61, 66, 86(1)(e) and 181 of the Electricity Act, 2003 (Act 36 of 2003) and all other powers enabling it in this behalf, and after previous publications, the …………………….(Name of State) Electricity Regulatory Commission hereby makes the following Regulations for the Intra-State Essential Reliability Services Operations:

1. Short Title and Commencement
    i. These Regulations may be called the ……………… (Name of State) Electricity Regulatory Commission (Intra-State Essential Reliability Services Operations) Regulations, 20XX
    ii. These Regulations may come into force from the date of their notification in the Official Gazette
    iii. These Regulations shall extend to the whole of the State of……..
2. Definitions and Interpretations
    i. In these Regulations, unless the context otherwise requires,
    a) “Act” means the Electricity Act, 2003 (36 of 2003) and subsequent amendments thereof;
    b) "actual drawal" in a time-block means electricity drawn by a buyer, as the case may be, measured by the interface meters;
    c) "actual injection" in a time-block means electricity generated or supplied by the seller, as the case may be, measured by the Interface meters;
    d) "beneficiary" means a person who has a share in an Intra-State Generating Station;
    e) “Commission” means the ……………….(Name of State) Electricity Regulatory Commission constituted under the Act;
    f) "Congestion" means a situation where the demand for transmission capacity exceeds the Available Transfer Capability;
    g) “Detailed Procedure” means the procedure issued under regulation 14;
    h) "Deviation" in a time-block for a seller means its total actual injection minus its total scheduled generation and for a buyer means its total actual drawal minus its total scheduled drawal;
    i) "Grid Code" means the Grid Code specified by the ……………….(Name of State) Commission under the Act;
    j) "interface meters" means interface meters as defined by the Central Electricity Authority under the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time;
    k) "Load Despatch Centre" means ……………….(Name of State) Load Despatch Centre, responsible for coordinating scheduling in accordance with the provisions of Grid Code;
    l) "Nodal Agency" means the System Operator, namely ……………….(Name of State) Load Despatch Centre who shall be responsible for implementation of the essential reliability services operations at the intra-state level.
    m) “Virtual Ancillary Entity” means a virtual entity participating in the ……………….(Name of State) Deviation Pool, as operationalized under State Electricity Regulatory Commission Regulations,

which shall act as the counterparty for the schedule prepared for despatch of essential reliability services providers (to convert single entry to a double entry system);

n) "Essential Reliability Services or ERS" means Ancillary Services that consist of either Regulation Down Service or Regulation Up Service;

o) "Essential Reliability Services Provider or ERS Provider" means the Intra-State Generating Stations eligible to participate in the ERS, for providing Regulation Up or Regulation Down service;

p) "Regulation Down Service" means an ERS that provides capacity that can respond to signals or instruction of the Nodal Agency for decrease in generation, within the technical limit and time limit, to respond to changes in area control error or congestion in the system;

q) "Regulation Up Service" means an ERS that provides capacity that can respond to signals or instruction of the Nodal Agency for increase in generation, within the technical limit and time limit to respond to changes in area control error or congestion in the system;

r) “Spinning Reserve” means “the capacity which can be activated on decision of the system operator and which is provided by devices which are synchronized to the network and able to effect the change in active power

s) "state entity" means a person whose metering and energy accounting is done at the state level;

t) "Scheduled generation" at any time or for a time block or any period means schedule of generation in MW or MWh ex-bus given by the concerned Load Despatch Centre;

u) "Scheduled drawal" at any time or for a time block or any period time block means schedule of drawal in MW or MWh ex-bus given by the concerned Load Despatch Centre;

v) "time-block" means a time block of 15 minutes each for which special energy meters record values of specified electrical parameters with first time block starting at 00.00 hrs;

w) “un-requisitioned surplus” means the reserve capacity in a generating station that has not been requisitioned and is available for despatch, and is computed as the difference between the declared capacity of the generation station and its total schedule under long-term, medium-term and short-term transactions, as per the relevant regulations of the Commission.

ii. All other words and expressions used in these Regulations, although not specifically defined herein above, but defined in the Act, shall have the meaning assigned to them in the Act. The other words and expressions used herein but not specifically defined in these Regulations or in the Act but defined under any law passed by the Parliament applicable to the electricity industry in the State shall have the meaning assigned to them in such law.

3. Objective

i. The objective of these regulations is to balance the supply and demand in the state, relieve the congestion in the Intra-State transmission system and to optimize the despatch of electricity incorporating reserves.

4. Scope and applicability

i. These regulations shall be applicable to the Intra-State Entities (other than Hydro & Renewable generators) involved in the transactions facilitated through short-term open access or medium-term open access or long-term access.

5. Eligibility for participation for Intra-State Essential Reliability Services
    i. All ………………(Name of State) Generating Stations and whose tariff is determined or adopted by the Commission for their full capacity shall provide Intra-State ERS.
    ii. All other State Generating Stations whose tariff is not determined or adopted by the commission may also be considered for Intra-State ERS. The consolidated tariff may be considered as 303.04 Paise/kwh.
6. Control period
    i. The Regulations shall come into force from the date of notification in the Official Gazette.
7. Role of Nodal Agency
    i. Nodal Agency shall prepare merit order stack of Intra-………………(Name of State) Generating Stations as stipulated in regulation 6.2 and take despatch decision.
    ii. For Regulation-Up, the Nodal Agency shall prepare stack of un-requisitioned surplus capacities available in respect of Intra-………………(Name of State) Generating Stations from lowest variable cost to highest variable cost in each time block, and taking into account ramp up or ramp down rate, response time, transmission congestion and such other parameters as stipulated in the Detailed Procedure. For Regulation-Down, a separate merit order stack from highest variable cost to lowest variable cost incorporating technical parameters as above shall be prepared.
    iii. Nodal agency shall prepare merit order stack factoring intra- state transmission constraints, if any.
    iv. Nodal Agency shall monitor the area control error, violation of transfer capability limits etc.
    v. Nodal agency shall direct the selected ERS Provider(s) based on the merit order for economical despatch for Regulation Up and Regulation Down, as and when requirement arises in the system on account of any of the following events:
    a) Extreme weather forecasts and/or special day;
    b) Generating unit or transmission line outages;
    c) Trend of load met;
    d) Trends of area control error;
    e) Any abnormal event such as outage of hydro generating units due to silt, coal supply blockade etc.;
    f) Excessive loop flows leading to congestion; and
    g) Such other events.
    vi. Nodal agency shall direct the selected ERS Provider(s) to withdraw their services after the circumstances leading to triggering of ERS no longer exist. The time-frame for withdrawal of service shall be determined as per the Detailed Procedure.
8. Role of Intra-State Essential Reliability Services Provider (ERS Provider)
    i. The ERS Provider shall on monthly basis submit the following to the Nodal Agency.
    a) Maximum possible ex-bus generation (MW) including overload if any (P_{max})
    b) Minimum turn down level (MW) (P_{min})
    c) Type of fuel

d) Fixed cost (paise/kWh upto one decimal place)
e) Energy charge rate (paise/kWh upto one decimal place)
f) Ramp up rate (MW/min) for each unit
g) Ramp down rate (MW/min) for each unit
h) Start up time from cold start (in minutes)
i) Start up time from warm start (in minutes)
j) Minimum up time for a unit after synchronization (in minutes)
k) Minimum down time for a unit after desynchronization (in minutes)
l) Maximum number of units that can be started up simultaneously
m) Any other information / constraints

ii. The ERS Provider shall inject or back down generation as per the instruction of the Nodal Agency for Regulation Up and Regulation Down respectively.

9. Ensuring adequacy of reserves

i. The reserve requirement shall be assessed by the SLDC on an annual basis from the past area control error (ACE) of the State.
ii. Security Constrained Unit Commitment (SCUC) shall be carried out on a day-ahead basis by the SLDC to facilitate reliability of supply within the State taking into account optimal cost, adequate reserves, ramping requirements factoring security constraints:
iii. Provided that, the payment of carrying cost for the generation reserves committed through SCUC shall be as specified by the commission.
iv. Based on the SCUC instructions from SLDC, the generating station shall revise the on-bar DC (with due consideration to ramp up/down capability), off-bar DC and ramp up/down rate.

10. Despatch of reserves

i. In the real time, Security Constrained Economic Despatch (SCED) shall be implemented by the SLDC for co-optimization of energy and reserves.
ii. Generation under the ERS shall be scheduled to the Virtual Ancillary Entity as decided by the Nodal Agency.
iii. Once the time period as specified by the Nodal Agency in the scheduled procedure starts, ERS shall be deemed to have been triggered.
iv. The schedules of the ERS Provider(s) shall be considered as revised by the quantum scheduled by the Nodal Agency under ERS.
v. Any deviations in schedule of ERS Provider(s) beyond the revised schedule shall be treated in accordance with the -……………….(Name of State) Regulations.

11. Withdrawal of ERS

The Nodal Agency, having been satisfied that the circumstances leading to triggering of ERS no longer exist, shall direct the ERS Provider(s) to withdraw with effect from the time block as specified in the Detailed Procedure.

12. Scheduling of ERS

i. The quantum of generation dispatched shall be directly incorporated in the schedule of respective ERS Provider(s).

ii. For Regulation Up Service, power shall be scheduled from the generating station to the Virtual Ancillary Entity by the concerned Nodal Agency, until such time the Nodal Agency gives instruction for withdrawal of service.
iii. For Regulation Down Service, power shall be scheduled from the Virtual Ancillary Entity to the generating station, so that effective scheduled injection of the generating station comes down, until such time the Nodal Agency gives instruction for withdrawal of service.
iv. Separate statement shall be maintained along with State Deviation Settlement Account for ERS.
v. The energy despatched under ERS shall be deemed as delivered ex-bus.

13. Energy Accounting
   i. Energy Accounting shall be done by the Nodal Agency on weekly basis along with State Deviation Settlement Account based on interface meters data and schedule.
   ii. The Nodal Agency shall issue an Ancillary Services Statement along with the State Deviation Settlement Mechanism Account.

14. ERS Settlement
   i. The settlement shall be done by the Nodal Agency under the State Deviation Settlement Pool Account under separate account head of ERS.
   ii. The payment to ERS Provider(s) shall be from the State Deviation Settlement Pool Account Fund. There can be two types of pool. One is ZERO balance pool and other is pool having residual amount after settlement.
   iii. In case of ZERO balance (also known as revenue neutral) pool, payment under ERS from or to State DSM pool to be considered as a part of pool balancing and accordingly payable and receivable to be made equal.
   iv. In case of Non-ZERO balance pool, settlement towards ERS to be done directly with pool. In case of deficit pool, dispatch under ERS is not envisaged.
   v. The ERS Provider(s) shall be paid at their fixed and variable charges, with mark-up on fixed cost, as decided by the Commission through a separate order from time to time in case of Regulation Up services for the quantum of ERS scheduled from the pool.
   vi. Provided that, the fixed and variable charges allowed by the Commission and as applicable at the time of delivery of ERS shall be used to calculate the payment for this service and no retrospective settlement of fixed or variable charges shall be undertaken even if the fixed or variable charges are revised at a later date.
   vii. The ERS Provider(s) shall adjust the fixed charges to the original beneficiaries for the quantum of un-requisitioned surplus scheduled under Regulation Up service.
   viii. For Regulation Down service, the ERS Provider(s) shall pay back of the variable charges corresponding to the quantum of Regulation Down services scheduled, to the pool. Loss due to sub-optimal operation may be factored.
   ix. Any deviation from the schedule given under ERS shall be in accordance with the State Electricity Regulatory Commission Regulations, 2014

x. Sustained failure to provide the ERS (barring unit tripping) by ERS Provider(s) shall attract penalties on account of gaming. Violation of directions of Nodal Agency for ERS shall also make the ERS Provider(s) liable for penalties in terms of section 30 of the Act.

xi. No commitment charges shall be payable to the ERS Provider(s) for making themselves available for the ERS.

15. Detailed Procedure

i. The Nodal Agency shall, after obtaining prior approval of the State Commission, issue the Detailed Procedure within a period of 3 months of notification of these regulations.

ii. The Detailed Procedure shall contain the guidelines regarding operational aspects of ERS including scheduling and dispatch and any residual matter.

16. Power to give directions

i. The Commission may from time to time issue such directions and orders as considered appropriate for implementation of these Regulations.

17. Power to relax

i. The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

18. Power to amend

i. The Commission may from time to time add, vary, alter, suspend, modify, amend or repeal any provisions of these Regulations.

19. Power to remove difficulties

i. If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent to the provision of the Act and these Regulations, as may appear to be necessary for removing the difficulty.

(Secretary)

Annexure-V

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Ministry of Power
Government of India
https://www.nsgm.gov.in

Smart Prepaid Metering and Peak Load Management

70th Meeting of Forum of Regulators (FOR)

31st January 2020

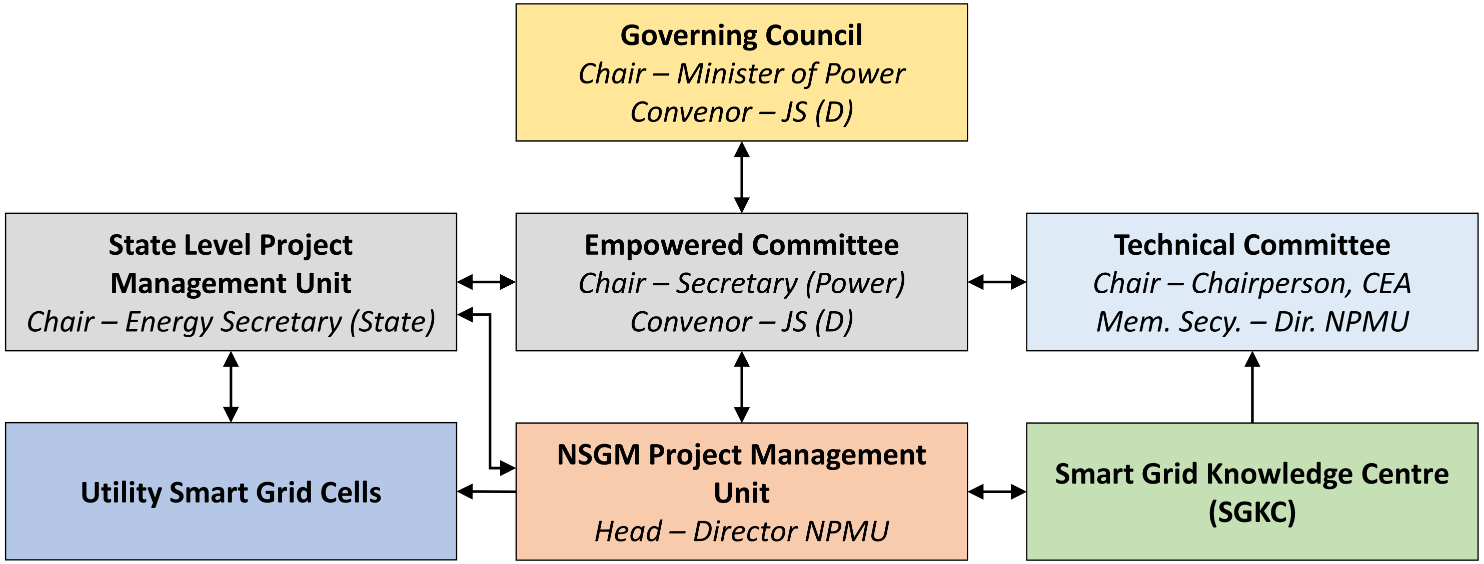
Agenda

- NSGM and Smart Grid Interventions
- Technology for Smart Grid Drivers
- Case for DR/PLM
- Smart Grid Regulations
- Expectations/Interventions sought

National Smart Grid Mission

National Smart Grid Mission
Ministry of Power
Government of India

NSGM has been established vide OM 20/13(2)/2009 –APDRP dtd 27th Mar 2015 and Extended till Mar 2020 vide OM dtd 7th May 2018 (Total Outlay 990 Crore with GBS of 312 Crore) with institutional framework as follows:



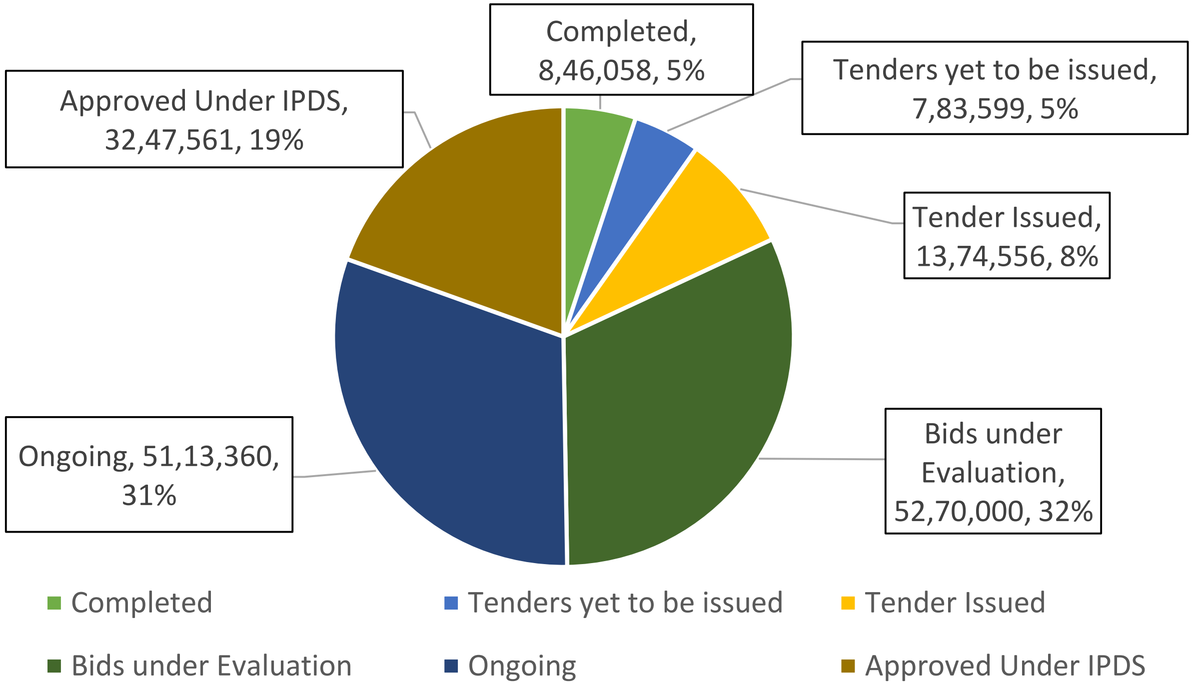
Bilingual website
https://www.nsgm.gov.in

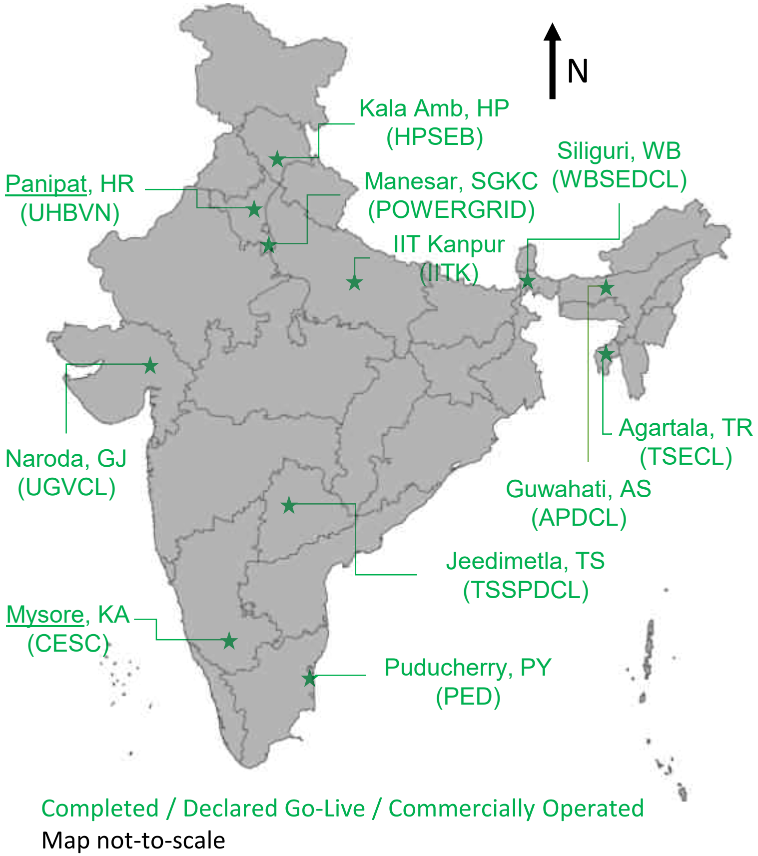
Smart Grid Interventions

- Deployment of Smart Meters and AMI
- Development of medium sized micro grids
- Development of distributed generation in form of rooftop PVs
- Real-time monitoring and control of distribution transformers
- Provision for harmonic filters and other power quality improvement measures
- Creation of EV charging infrastructure for supporting proliferation of EVs
- Substation renovation and modernization with deployment of GIS wherever economically feasible

Smart Metering Scenario in India

National Smart Grid Mission
Ministry of Power
Government of India





MoP Sanctioned Smart Grid Pilot Projects in India

Major Players/Aggregators/PMA

- **EESL**
- RECPDCL
- PFCCL
- POWERGRID

Top-5 Ranked Technologies for SG Drivers

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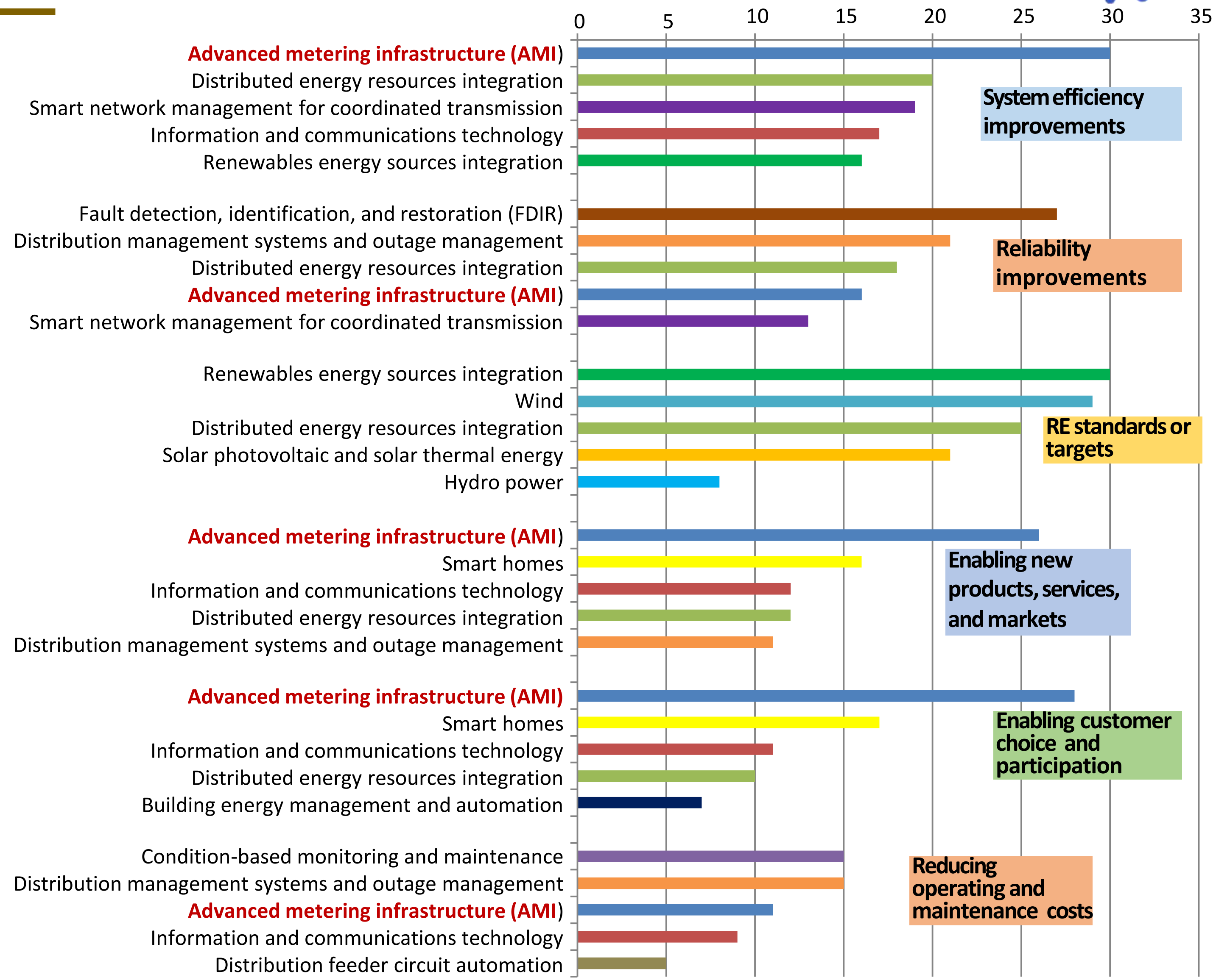
Government of India



Source: ISGAN Annex-2 Survey from 19 participants

Technology Readiness Levels for SG Drivers/Functions

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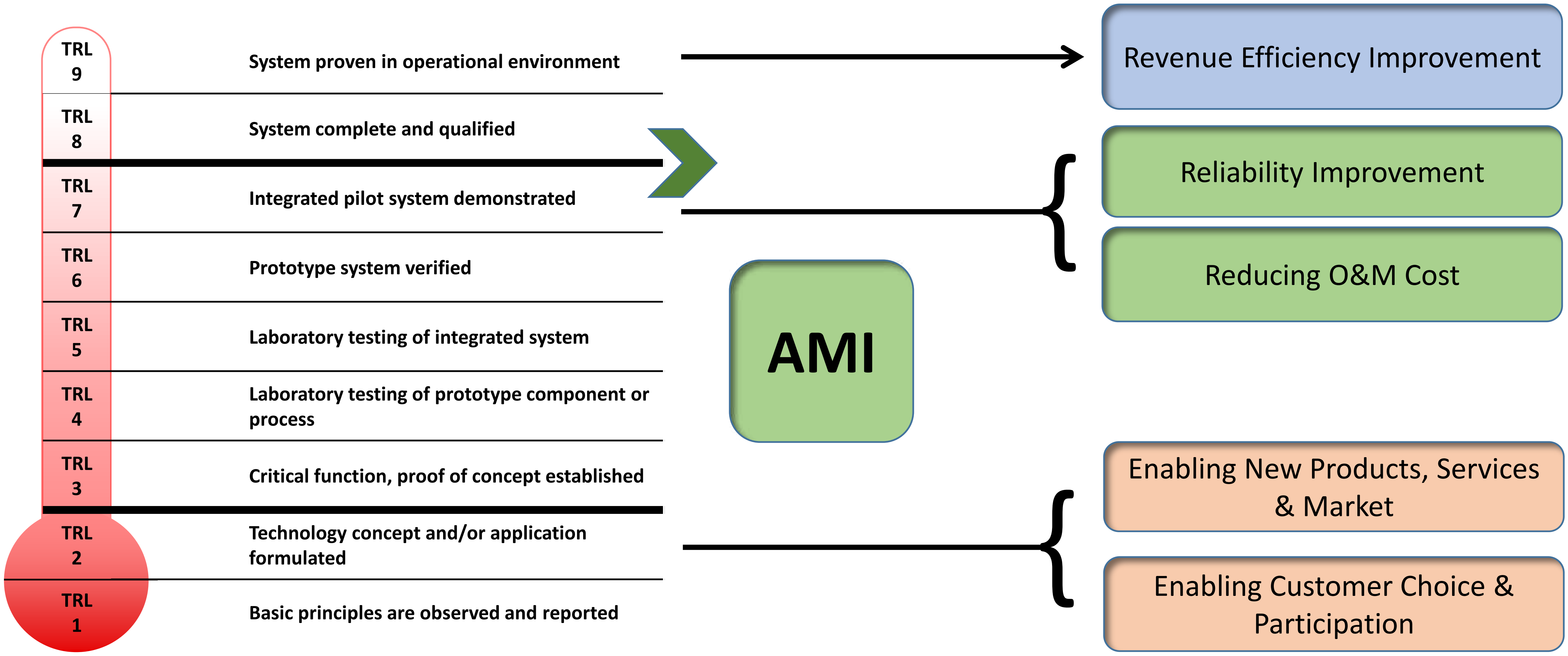
Ministry of Power
Government of India



Delhi: Seasonal Variations in FY 2018-19

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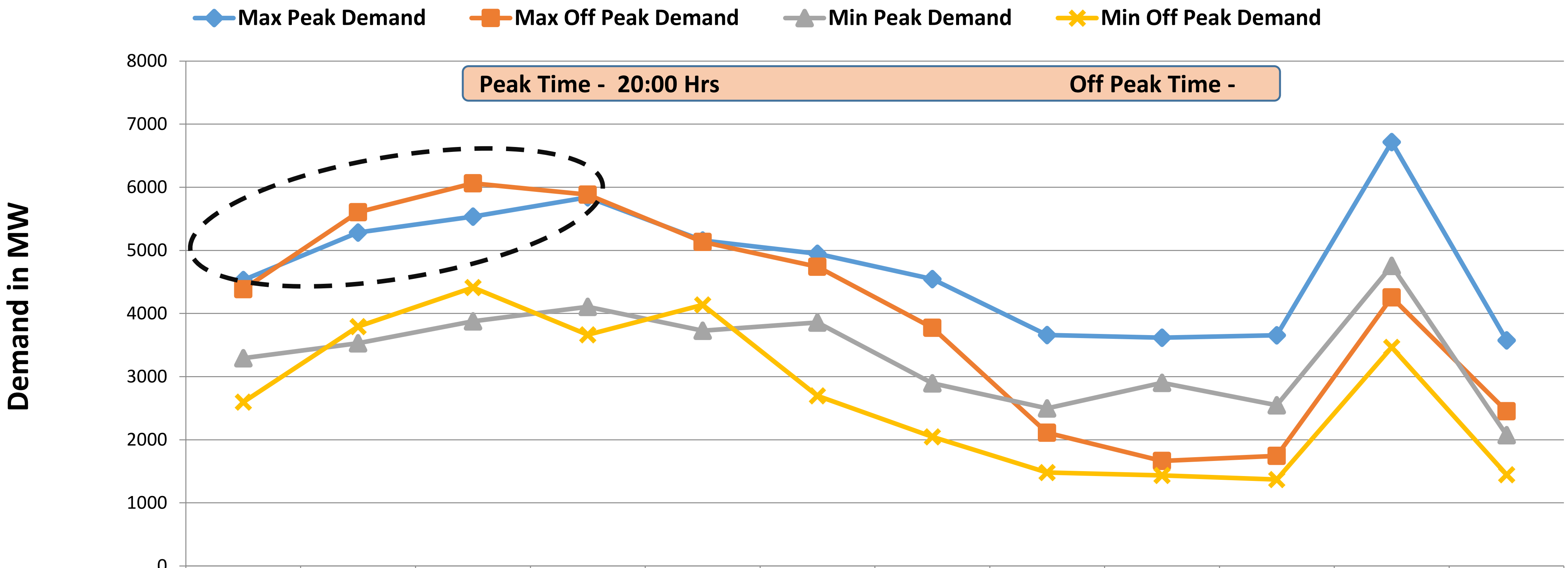

	Apr'18	May'18	Jun'18	Jul'18	Aug'18	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19
Max Peak Demand	4530	5283	5535	5842	5159	4948	4544	3660	3619	3657	6716	3577
Max Off Peak Demand	4387	5606	6062	5882	5134	4739	3773	2113	1664	1745	4257	2451
Min Peak Demand	3291	3528	3876	4107	3727	3857	2896	2499	2903	2548	4756	2074
Min Off Peak Demand	2598	3792	4412	3665	4138	2698	2048	1480	1435	1369	3463	1446

Max difference b/w Peak & Off peak Demand: 1955 MW (Dec.)

Source: https://nrldc.in/reports/monthly-reports/monthly-reports-2018-2019/

Punjab: Seasonal Variations in FY 2018-19

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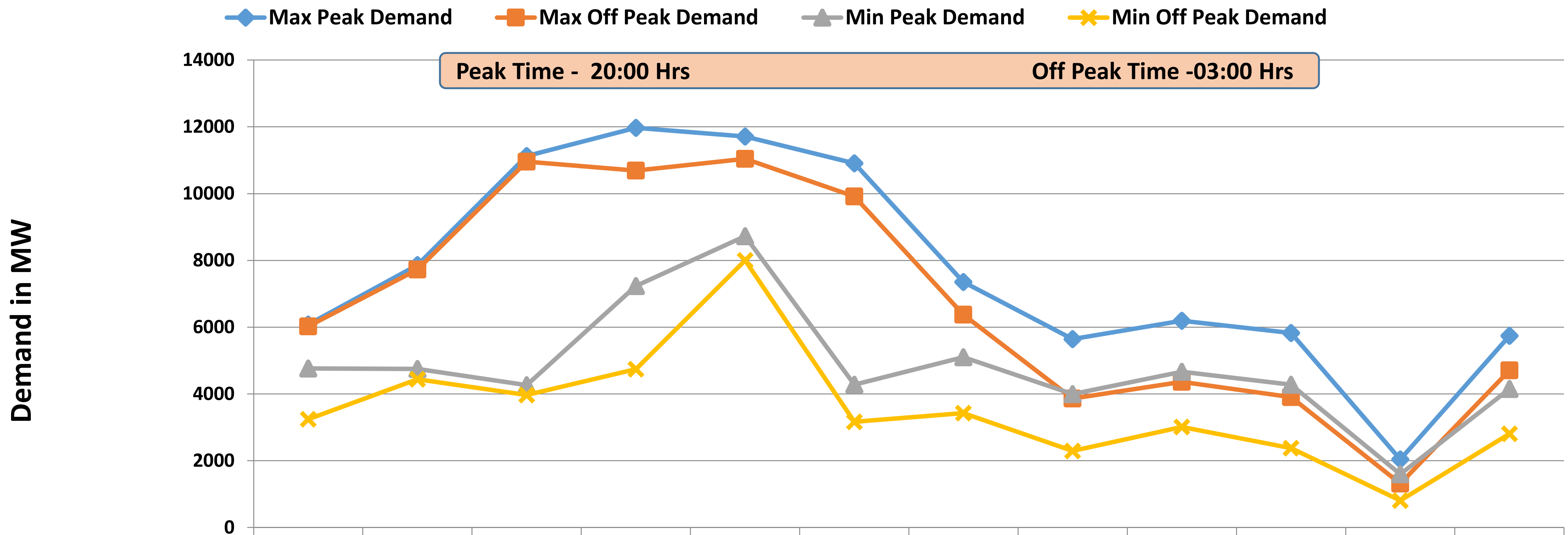

	Apr'18	May'18	Jun'18	Jul'18	Aug'18	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19
Max Peak Demand	6081	7860	11124	11970	11708	10910	7354	5644	6195	5828	2042	5740
Max Off Peak Demand	6021	7730	10957	10689	11041	9914	6373	3860	4363	3903	1313	4705
Min Peak Demand	4767	4747	4266	7232	8729	4276	5099	3997	4666	4279	1600	4149
Min Off Peak Demand	3242	4437	3969	4744	7999	3168	3426	2293	3015	2379	812	2810

Max difference b/w Peak & Off peak Demand: 1925 MW (Jan.)

Source: https://nrldc.in/reports/monthly-reports/monthly-reports-2018-2019/

Punjab: Monthly Peak/Off Peak Std. Deviation & Avg. of their Difference in FY 2018-19

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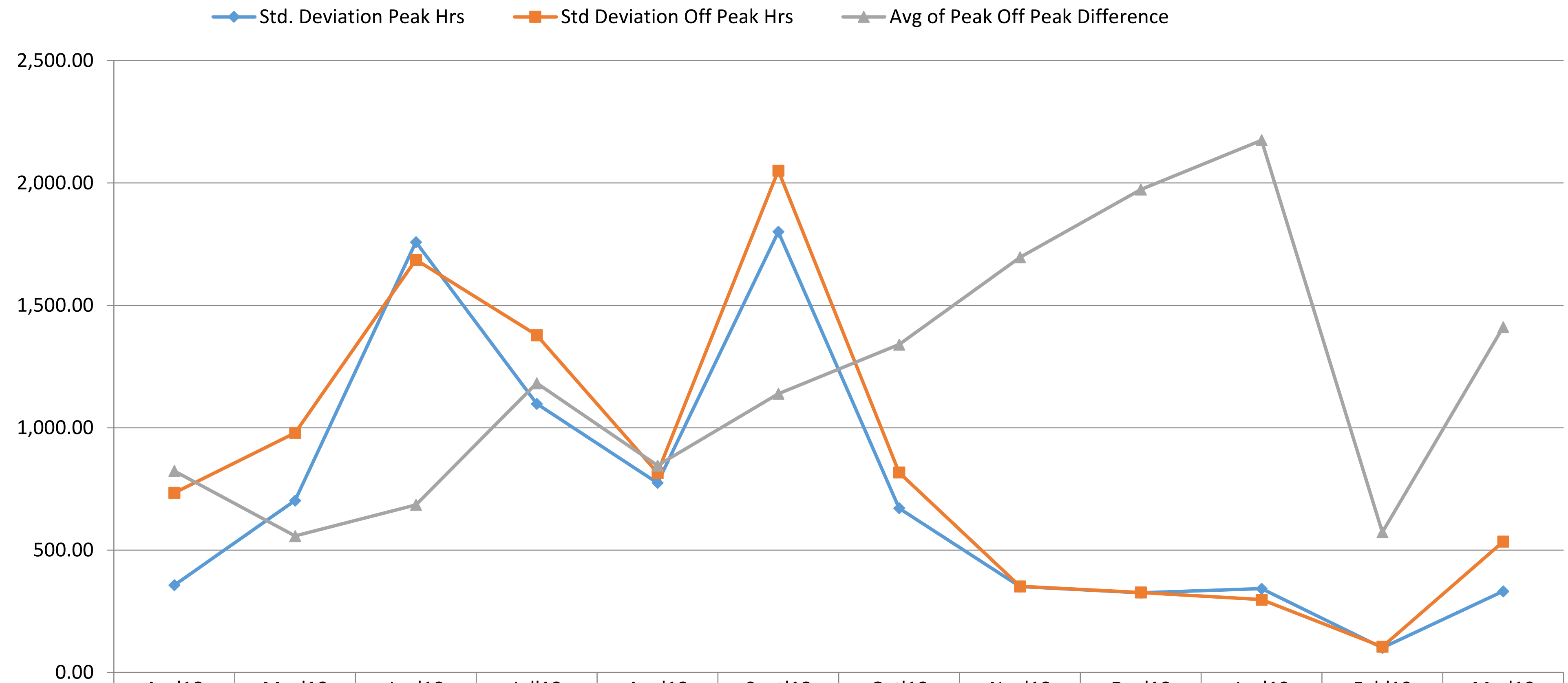
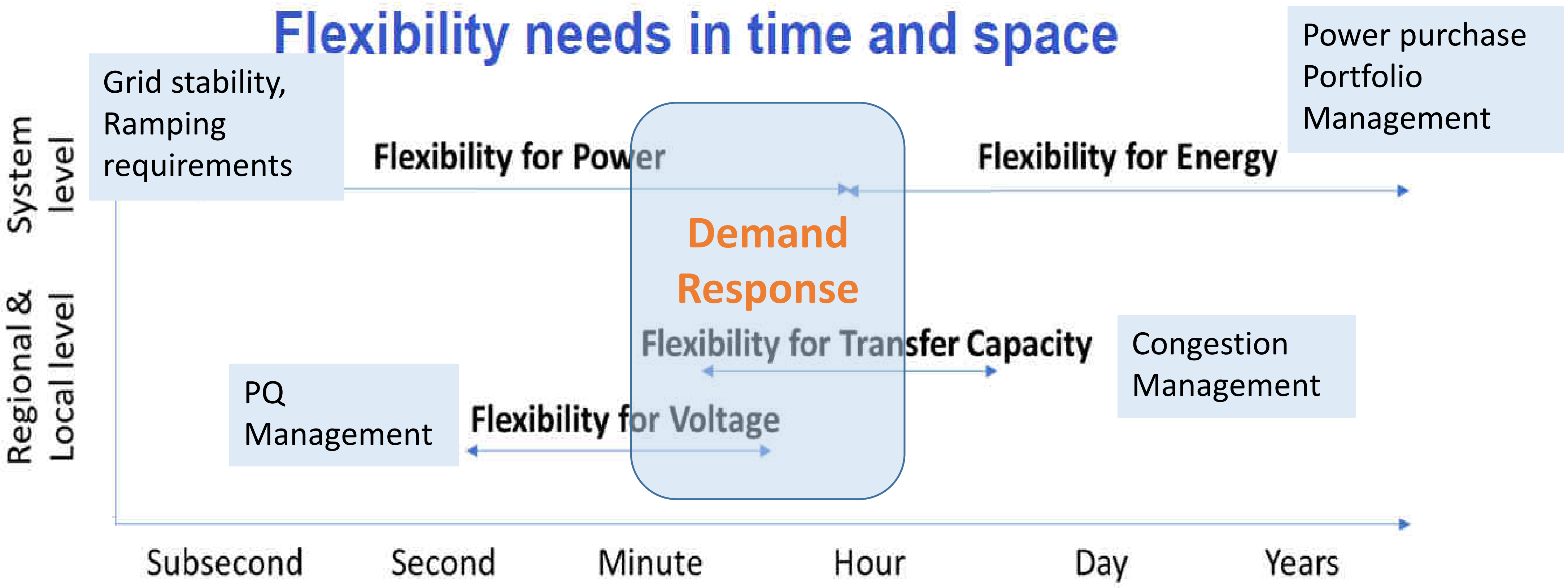


	Apr'18	May'18	Jun'18	Jul'18	Aug'18	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19
Std. Deviation Peak Hrs	356.71	702.33	1,758.61	1,097.90	774.21	1,801.06	671.20	350.86	325.77	342.15	100.41	331.58
Std Deviation Off Peak Hrs	734.13	979.33	1,686.27	1,378.37	815.61	2,051.03	817.17	351.59	326.77	297.26	105.25	534.38
Avg of Peak Off Peak Difference	823.74	557.68	684.74	1182.16	845.45	1138.77	1340.06	1696.68	1973.55	2174.87	573.10	1411.48

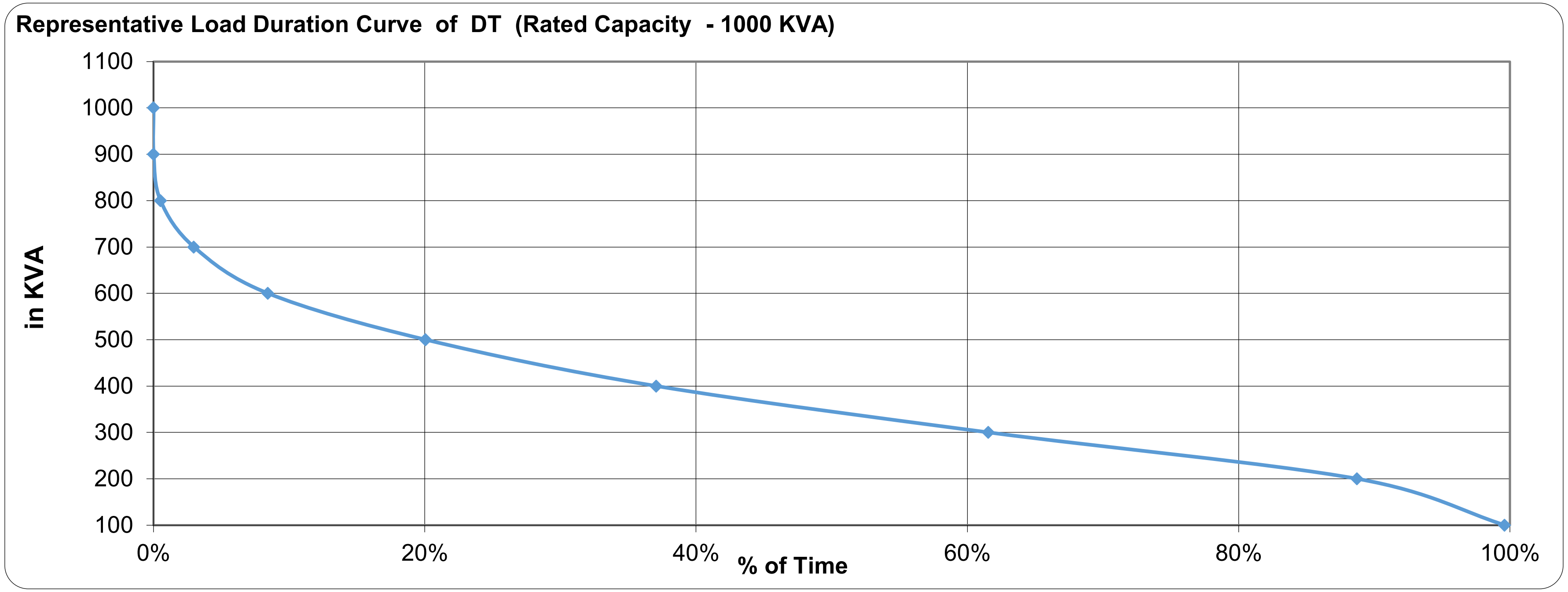
Flexibility Needs for System



BRPL Load Pattern

	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Base Load	1534	1597	1595	1671
Intermediate Load	516	515	662	673
Peak Load	615	576	715	807
Total Peak Load	2665	2688	2972	3151

Base Load increased 4.1% in 17-18, flat in 18-19 and increased by 4.8 % in 19-20.
Peak Load reduced by 6.3% in 17-18 increased by 24% in 18-19 and 12.9% in FY 2019-20.



Source: Input from BRPL, Delhi

Draft India Cooling Action Plan (ICAP)

The draft India Cooling Action Plan (ICAP) was released by Ministry of Environment, GoI

- India's present per capita cooling energy consumption - 69 KWh
- Average global cooling energy consumption- 272 KWh per person

India's aggregate cooling requirement may ↑ 8 times in next 20 Years.

- Building sector (space cooling) to ↑ approx. 11 times
- Transport cooling to ↑ 5 time and 4 times ↑ in cold chain and refrigeration sector.
- All these sectors together ↑ 4.5 times energy in next 20 years.

➢ **Business opportunity for DISCOM's ?**

➢ **Infrastructure Capacity challenge?**

➢ **Customized DR/ DSM programs for cost effective operations ?**

Source: https://timesofindia.indiatimes.com/articleshow/65849491.cms

EVs and ACs Growth in India

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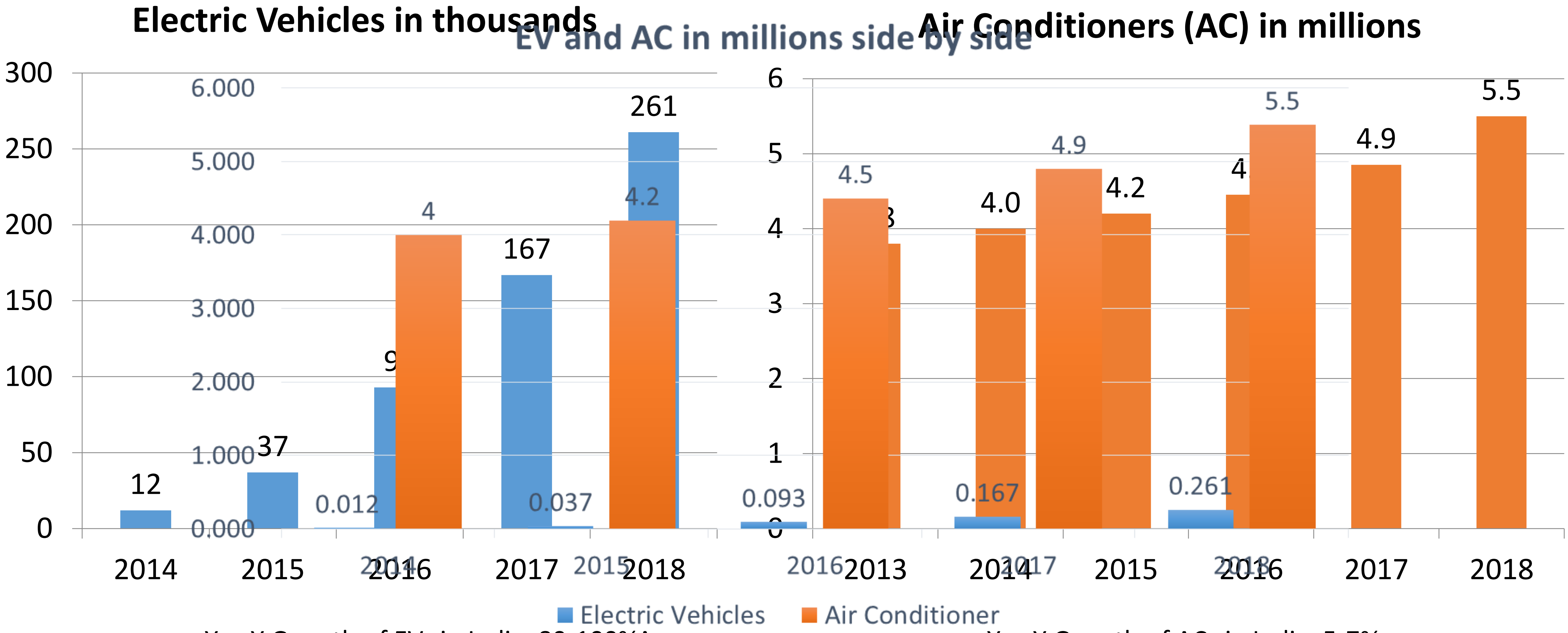

Y-o-Y Growth of EVs in India: 80-100%^
EV30@30: 30% of market share shall be EVs by 2030 – CEM

Y-o-Y Growth of ACs in India: 5-7%
Estimated Growth by 2024: 12-15%*

^ Sources: https://bit.ly/2I9ONIK, https://bit.ly/2Fz5lfe, https://www.fame-india.gov.in

* Sources: https://bit.ly/2QU7szq, https://bit.ly/2SI0Fpy, https://bit.ly/2Eslqm4

Electrical Energy and Peak Demand Projection v/s Growth

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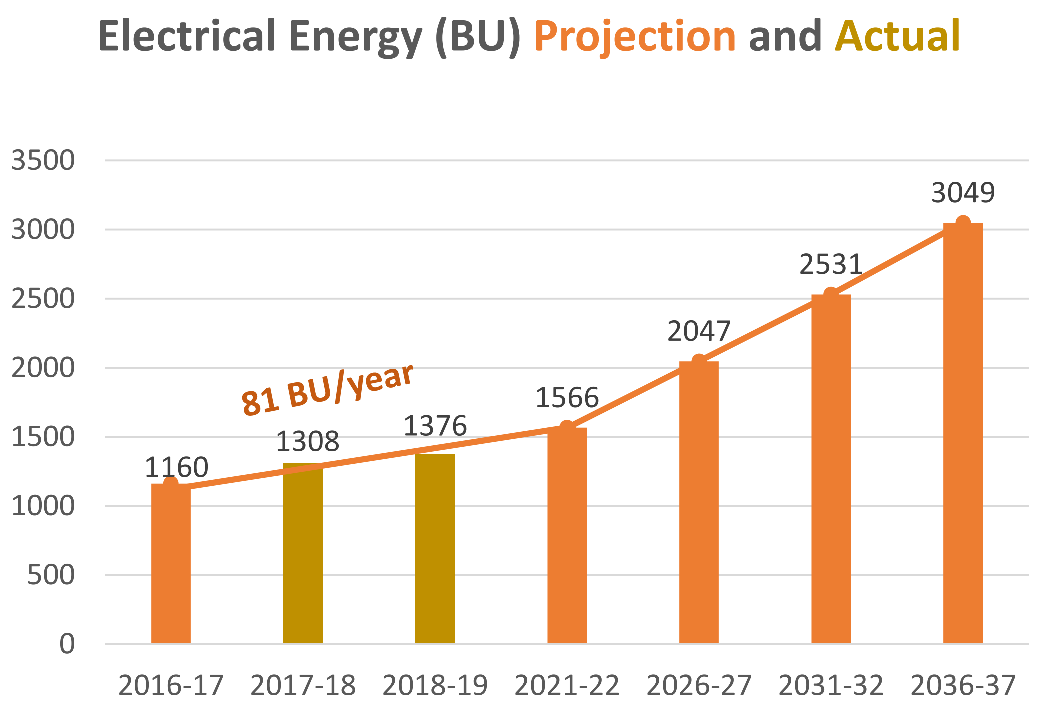

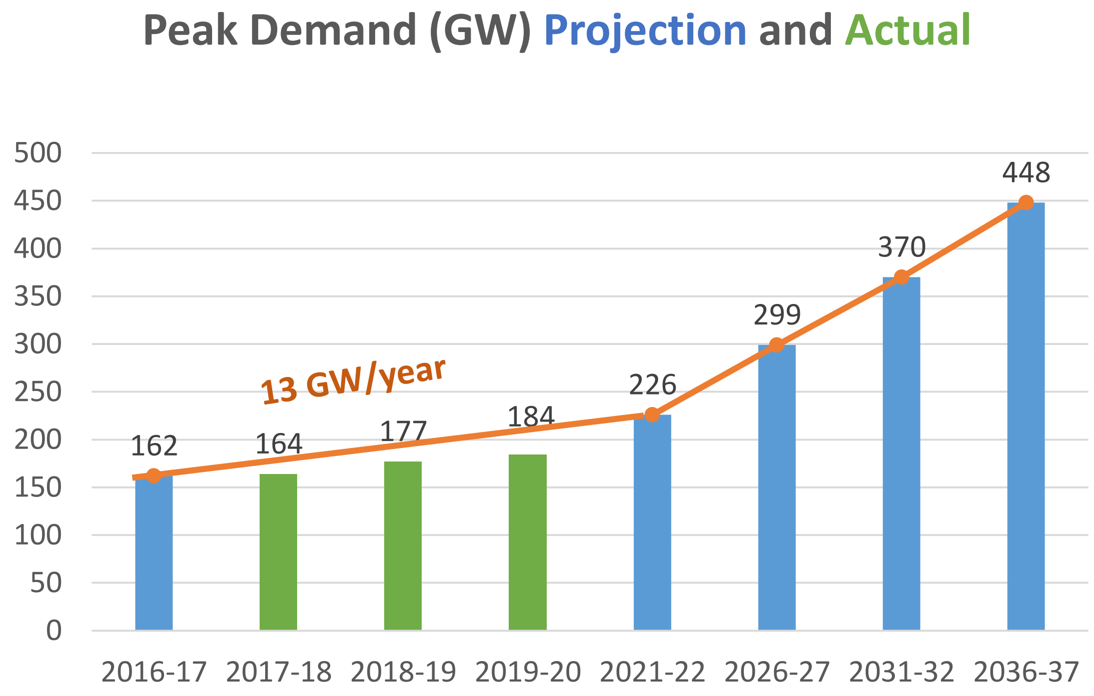

Source: CEA 19th EPS & CEA Annual Report

DR and DSM

Demand Response (DR)

- L5: Automated DR program implemented covering at least 30% of consumers
- L4: Automated DR program implemented covering at least 20% of consumers
- L3: DR program implemented on larger scale covering at least 10% of consumers
- L2: DR business case developed basis load research study, Basic DR pilot program initiated
- L1: No DR implementation by Discom

Demand Side Management (DSM)

- L5: Integration of DSM and operation of the distributed generation
- L4: Utility controlled DSM, superseding the load curtailment by user allowed
- L3: Utility signs agreement with user for remote control (cutoff supply during peak periods) of certain loads by utility (meters facilitated with remote connect/disconnect feature), superseding the load curtailment by use not allowed
- L2: DSM based on day ahead forecasting and scheduling
- L1: No DSM mechanism in place

Demand Response for Flexibility

- The current pricing mechanism
  - once a year,
  - basis: DISCOM Load pattern (ToD) and Consumer Class
- No signal to consumer for change in use of electricity.
- If we add some dynamic price component to existing tariff
  - +xx% that could reflect the real time imbalances,
  - End consumers may shift their load
    - Initial participation may be based on Contract – Enable DISCOM to excel with partnership
- This necessitates design of Dynamic tariff to deliver flexibility in grid operation– variables being
  - Cost,
  - Time and
  - Geography
- In various pilot smart grid projects in the US, participating customers were guaranteed a neutral bill impact from participation, this way we can get better participation in Treatment Group.
- As per Delhi & Punjab Experiment , there seems a probability that consumers will shift/ reduce their loads when ToU tariff is high during peak time(and/or if there is a discount at off peak time)

Demand Response Scenario

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DR for Peak Load Management for deferring Infrastructure upgrades

- Few day ahead events of few hours in a year for all consumers

DR for promoting DERs, consumer bill reduction and voltage support

- Promoting electric stove usage or EV charging when solar output is high

DR for EV charging infrastructure support

- Time slot based rates for public charging infrastructure

DR for minimizing / optimizing power purchase cost

- Real time local energy system balancing by integrating energy storage

DR for Congestion management (Circle, Feeder, DT)

- Day ahead events on need basis

DR for Grid stability

- Real time load reduction preferably be large C&I consumers

Stakeholder Benefits from DR

Stakeholder	Benefit
Consumers	• Financial incentive for participating in schemes • Provides focus on energy efficiency • Improved supply reliability (in the long term) • Reduced cost of power (in the long term)
DISCOM	• Provides focus on load patterns and energy efficiency • Low cost/fast to deploy mechanism to balance supply and demand • Avoided cost in purchasing expensive power from wholesale market/short term contracts required to meet supply deficit • Deferral of asset investment for infrastructure required only to meet peak demand • Improved revenue due to avoidance of load shedding through better load management • Increased integration of RE resources into the grid
System Operators	• Low cost/fast to deploy mechanism to provide ancillary services
Regulators	• Provides an additional resource to help address power shortages • Demonstrates a move towards energy efficiency and greener solutions for meeting load requirements • Positive impact on cost of power to consumers as DISCOMs and system operators rely less on purchasing expensive power
Economy	• Positive impact on cost of power to consumers as DISCOMs and system operators rely less on purchasing expensive power • Low cost/fast to deploy additional resource to help address power Shortages
Environment	• Less dependence on thermal power required to manage balancing and regulation issues. • Deferral of asset investment for infrastructure required only to meet peak demand. • Increased RE penetration

Source: USAID Smart Grid Training Course Material

Dynamic Tariff Option for DR

	Components considered for tariff design
Components of ARR	Cost of generation and transmission Service cost of DISCOM Reactive power consumption Voltage level Sanctioned/contracted load Subsidy Class of consumers
Proposed	ToD or pre-announced prices based on a forecast for peak load hours ToU/CPP that can be linked to Cost of purchase or an average of daily maximum demand Power supply quality- based on voltage fluctuations, reliability, power factor and harmonics

White paper: https://www.nsgm.gov.in/sites/default/files/Dynamic%20Tariffs%20White%20Paper.pdf

DR Case Study

BSES Yamuna

- BSES Yamuna implemented DR program to manage its peak load and maintaining tie- line schedule
- Overall, 9-15 consumers participated in each event,
- Resulted in demand savings of 0.89 to 3.45 MW per event
- Maximum reduction provided by manufacturing units, followed by hotels, malls, hospitals, and others

Tata Power, Delhi

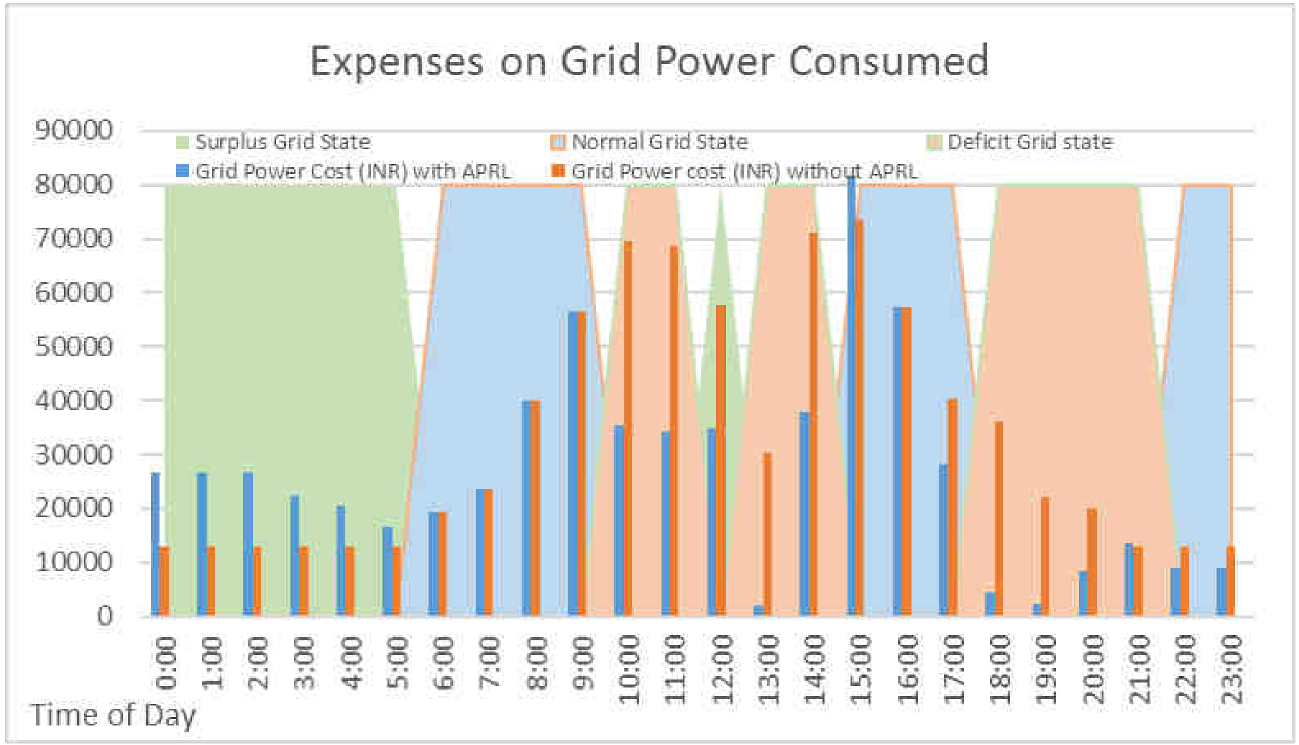
- Participation - 161 customers > 100 kW (cold storage, commercial, education, flour mill, hospital, industrial, pumping, retail etc.)
- 17 DR events for 30 to 60 minutes each in the summer of 2014
- Achieved max shed potential of 7.2 MVA with a cumulative saving of 0.063 MUs.
- Max demand reduction ranged from 2% (for Education) to 28% (for Packaging)

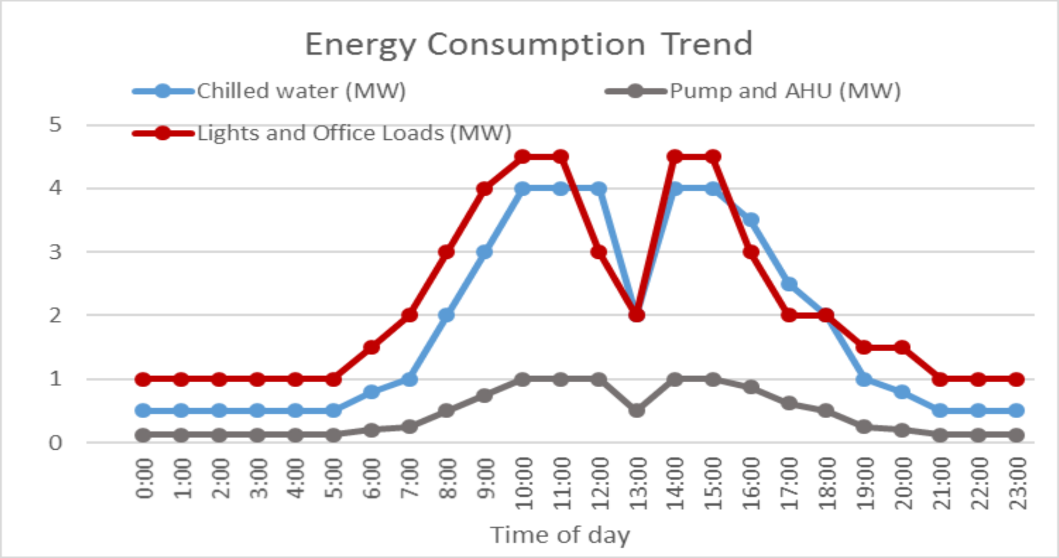
Tata Power, Mumbai

- Tata power, Mumbai implemented both aggregator based and auto DR projects in Mumbai at Malls, Hospitals, IT parks and Municipal sewage treatment plants etc.
- Aggregator level DR was triggered 21 times each for duration of 2 hours
- 15 MW curtailment achieved

Demand load management and optimized consumption through Available Power Responsive Loads (APRL)

Use Grid-prices to drive **Available-Power Responsive Loads (APRL)** adoption.





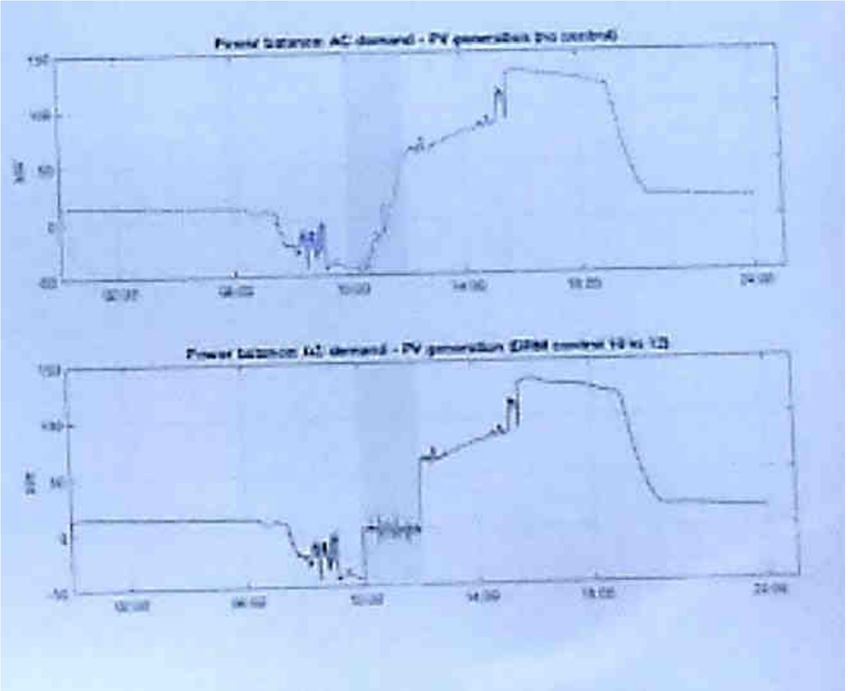
The total cost saving due to APRL amounts to ₹1.6 lakhs per day or about ₹50 lakhs per month.

Note: Savings shown are over and above the savings envisaged due to use of DC equipment, use of VFD in AHU and VAVs and use of roof-top solar.

✓ Demand load management and optimized consumption through APRL clubbed with different types of storages is a huge electricity cost saver

CSIRO Experiment with Solar PVs and ACs

- Impact of PV natural intermittency:
  - Sudden PV output drop due to clouds can have significant impact on network
- AC loads drive peak demand:
  - AC demand follow ambient temperature. Demand of 70 residential consumers studied with ambient temperature
- Result:
  - AC loads to be coordinated to follow fluctuations in PV output and reduce grid stress
  - ACs can behave as virtual battery providing up to 94% reduction in solar variability



Source: CSIRO, Australia

Where to Experiment Now

- **New Products** viz. *for Energy Management*
- **New Services** viz. *Peer-to-Peer exchange of energy and flexible services*
- **Platform Solutions** viz. *Distributed ledgers with Blockchain*
- **New Tariff Models** viz. *Grid tariffs for battery storage etc.*
- **New Business Models** viz. *Local Energy Community*

Way Ahead / Interventions

- Smart Grid Pilots have been completed & opportunity available to generate insight:
  - Data Analysis
    - Demand Response
    - Peak Load Management
    - Time of Day / Time of Use Tariff implementation
    - RE localisation / sizing for smooth integration
    - Load Balancing
    - Loss reduction
    - Reliability Improvement
  - Customer Engagement
    - Customer Portal on Mobile (Android/iOS)
    - Feedback /Complaint, Customer Care
    - Social Media / Chat-bots for customer interaction etc.

Thank You

www.nsgm.gov.in *@NsgmIndia*

Annexure-VI

GOVERNMENT OF INDIA
MINISTRY OF POWER

UK Government

Presentation on beta version of:

Regulatory Tool

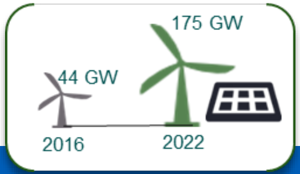
(Electricity Regulatory Information Access and Analytics Platform)

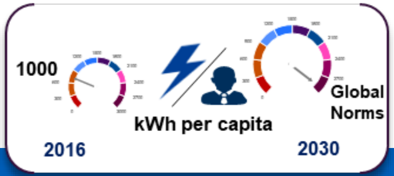
31st January, 2020

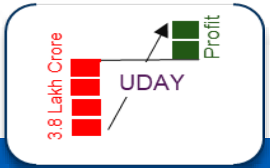
Contents

This presentation has been prepared under the Technical Assistance titled "Supporting Structural Reforms in the Indian Power Sector (or the Power Sector Reforms Programme)" funded by UK aid from the UK government; however the views expressed do not necessarily reflect the UK government's official policies. KPMG in India is the lead service provider of the Technical Assistance.

PSR Programme has been designed to meet critical needs of the power sector







Design Interventions	Sustainability	Modernization	Viability
	➢ RE deployment and integration ➢ GHG reduction in electricity sector ➢ Market and financial innovation	➢ Conducive markets for private sector participation ➢ Increased public and private investment ➢ Increased access to reliable electricity	➢ AT&C loss reduction ➢ Cost reflective tariff ➢ Better targeted subsidy

Key Stakeholders

- Ministries: MoP, MNRE
- Central Agencies: CEA, CERC, PFS, NSGM, FOR, REC, EESL, UDAY Cell
- States: Haryana, Rajasthan, Jharkhand, Andhra Pradesh, Telangana, Odisha

Work Streams

- RE Deployment and Grid Integration
- Structural & Regulatory Reforms
- Power Markets
- Utility Sustainability
- 24X 7 Access & Stakeholder Welfare
- Impact Initiatives

The Regulatory Tool has been developed in consultation with the MoP and FOR by KPMG in association with ABPS Infrastructure Advisory Pvt Ltd

Rationale

- ❑ Electricity regulatory information is available in different forms (Tariff Orders; Petitions, Regulations, etc.)
- ❑ It is imperative to make available this information on a single platform to support decision making. This would facilitate exchange of information, knowledge and experiences among SERCs

Objectives

Data Analytics

- ✓ Enable data analytics
- ✓ Improve root cause analysis

Decision Support

- ✓ Benchmarking
- ✓ Comparative assessment & analytics

Knowledge Exchange

- ✓ State-wise information on a single platform
- ✓ Ease to understand visualization

Consumer Empowerment

- ✓ Improve information access
- ✓ Simplify data representation

Journey so far…(last 1.5 years)

Data Formats & Consultation	Data Collection & Analysis	Development of Regulatory Tool	Dissemination Workshop	Tool Enhancement
✓ Consultations with the FOR to identify key data points ✓ In-principle approval during 64th meeting of FOR (24.8.2018) ✓ Revised data formats based on comments received from 5 SERCs	✓ Data collection FY-15 to FY-18 ✓ Interactions with 5 SERCs ✓ Data validation by SERCs – 18 States have validated ✓ National and State level insight reports	✓ Developed web-based Regulatory Tool - ~1000+ graphics ✓ 3 – analytics tool for comparative assessment ✓ Presentation to the FOR Secretariat	✓ Demonstration workshop (Sept, 2019) ✓ Attended by 45 participants from 16 SERCs (including Chairman/Member from 2 SERCs) ✓ Inputs received for further enhancement	✓ Addressed comments received from SERCs ✓ Added new functionalities to the tool ✓ Seeking guidance from FOR for launch and Phase II Activities

Key Parameters Covered in the Tool

Regulatory Affairs		Regulatory Functioning	Planning Effectiveness	Consumer Protection	Financial & Operational Parameters	Other Parameters
Timelines for issuing tariff orders	Renewable Power Obligation	Budgetary support provided by state govt. to SERCs	Variations in approved, actual and trued up values of: 1.) Sales; 2.) Components of ARR; 3.) Power purchase cost; 4.) Distribution cost; etc.	Complaints received and resolved by CGRF and ombudsman	ARR and Tariff Details	Open Access Charges
Cost coverage through tariff	Fuel and power purchase cost adjustment (FPPCA)	Approved v/w vacant positions		Complaints pending for more than 2 months	Category wise Sales and Tariff	Generic Tariff Details for Renewable Energy
Regulatory assets	Regulations issued	No. of petitions disposed		Penalties imposed for non compliance		
Open access adoption		Functioning of State Advisory Committee				

Analytical Insights

- ✓ Benchmarking (based on user defined criteria)
- ✓ Custom visualization of performance parameters
- ✓ ACoS- ARR gap scenario analysis

Data Sources

1. SERC Orders
2. SERC Website
3. Annual Reports
4. Regulations
5. FOR

Key Functionalities of Regulatory Tool

Functionalities

Information Update
National & International Regulatory Affairs

National Dashboard
National & State wise Comparative Information

State Dashboard
Discom wise Comparative Information

Analytics Tools
Benchmarking; Custom Visualization and Scenario Analysis

Design and Access

1. Inputs through a **predesigned excel sheet**
2. Data **can be downloaded in excel/pdf formats**
3. **3 levels of access** have been be provided

Super-Admin
- Read, write and modify
- Allocate admin rights

Admin
- Read/write information for respective states

Public
- Read information
- Provide feedback

Functionalities of the Platform

1 **Homepage**

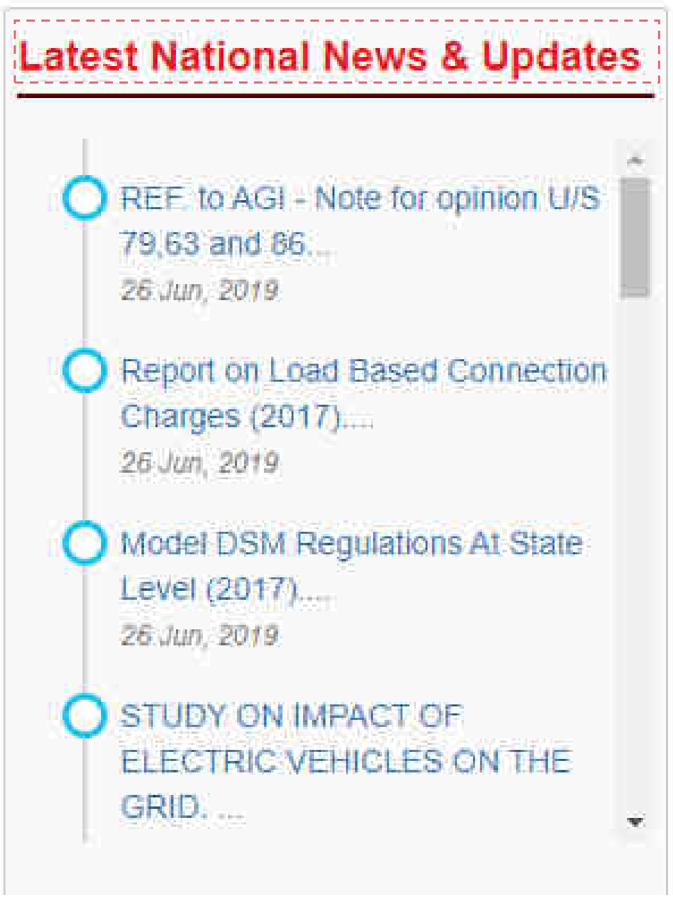
1. LOGIN: Admin login through unique ID and password
2. Go to dashboard- National and state level dashboards

Functionalities of the Platform

2 **Regulatory Updates**

1. Latest national regulatory updates
2. Latest international regulatory updates

1

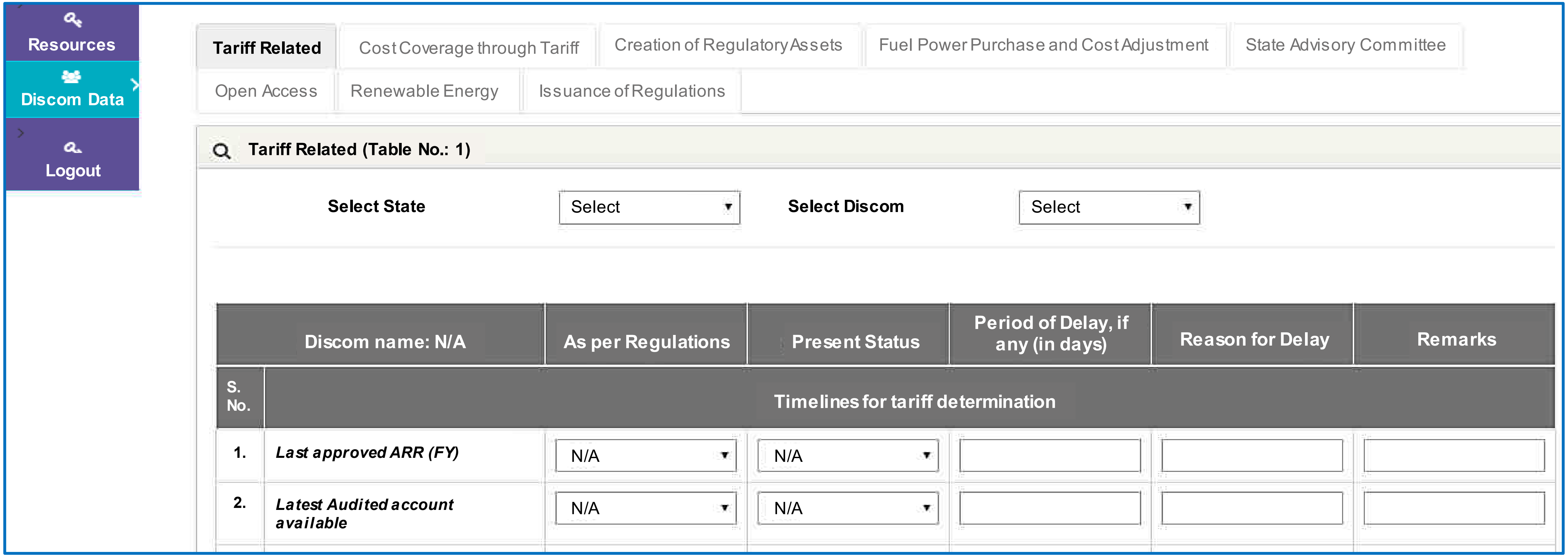


2

Functionalities of the Platform

3 **Information Update / Admin portal**

- Preloaded information for last 3 years (FY-16 to FY-18).
- SERCs to provide/validate information - 3 years support will be provided by PSR team



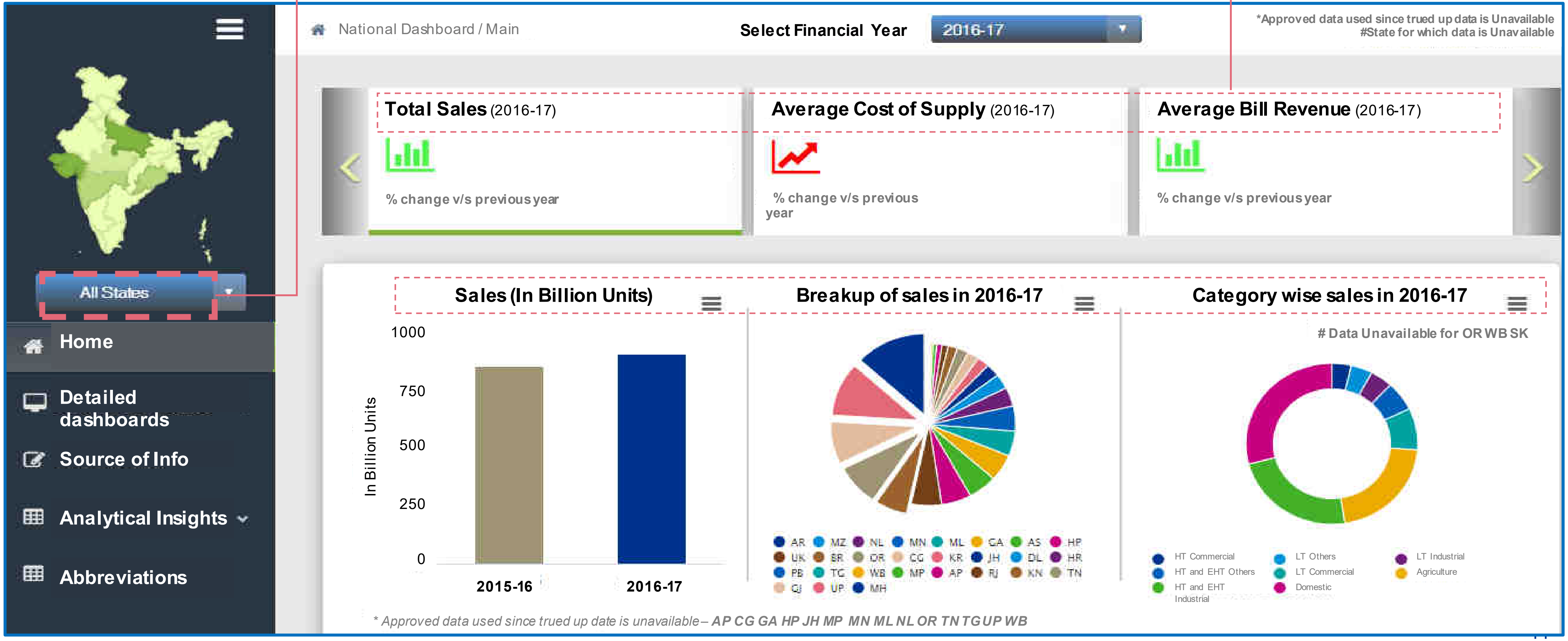
Functionalities of the Platform

4 National Dashboard

- National level information
- State level comparative information

Select "All States" or any particular state from dropdown

Various Parameters displayed.

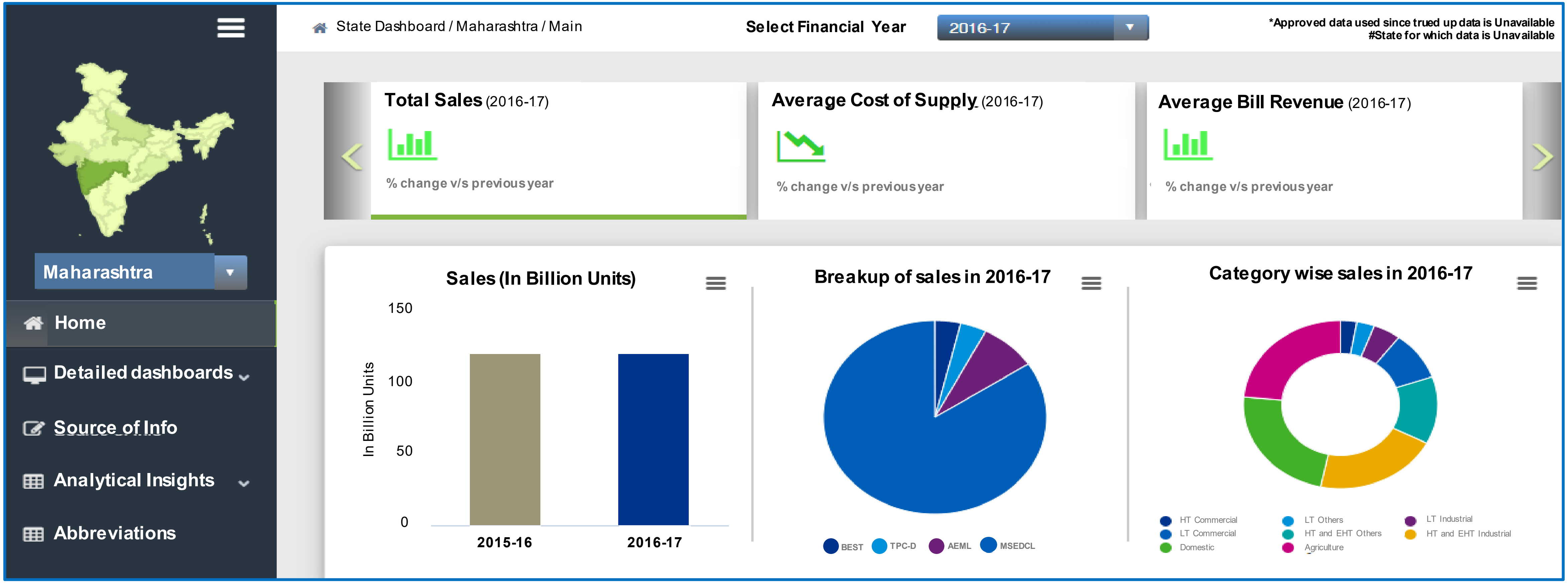


Details of one parameter

Functionalities of the Platform

5 **State Dashboard**

- Detailed state level information
- DISCOM level comparative information



Key activities during phase-II

Additional Data/Information

- No. of consumers
- Subsidy
- Generation source wise power purchase
- Capital exp.
- Tariff schedule

Data Update

- Data collection for FY-19 (validation from SERCs)
- Data update by SERCs (FY-20 and FY-21) directly into the portal

Analytics

- New visualization scenarios and analytics tools
- Periodic regulatory insight reports

State Reports

- APTEL compliance report incl. (timelines for tariff filing & issuing tariff order; FPPCA mechanism & periodicity)

O&M

- Fixing of bugs/errors
- Content changes and development of new content
- Integration with FOR website

Capacity Building

- Handholding support to the FOR and CER
- Capacity building and dissemination workshop

Way Forward..

Launch of Portal – Limited Access to SERCs

- Data validation (18 SERCs have validated)
- Comments and Suggestions

Update Portal

- Data collection for additional parameters (FY-15 to FY-18)
- Data update for FY-19
- Address comments

Launch of Portal - Hosting at FOR Website

- Hosting of tool at FOR website
- Official launch– access to all users
- Training workshop for SERCs

Data update ... (Contd. activity)

- Data update for FY-20 & FY-21 by SERCs
- Support for data validation

Dissemination

- Knowledge sharing and dissemination workshop

Operations & Maintenance of the Portal

Study on *"Analysis of Historical Trend of Electricity Tariffs"*

Analysis of Electricity Tariffs

Rationale: Various factors (controllable and non-controllable) affects cost of supply i.e. raw material cost, taxes / cess, efficiency, etc. A detailed analysis of assessing impact of these parameters (across the electricity value chain) on electricity tariff is required for informed decision making

Objective: To understand impact of variation in external parameters (i.e. fuel cost; taxes and cess, freight charges, RPO, etc.) on ACoS and electricity tariffs

Approach & methodology

Study States	Data Collection	Analysis	Draft Report	Dissemination
✓ 5 states – seeking buy-in SERCs ✓ Stakeholder consultation - SERCs & FOR	✓ Identification of key external factors ✓ Collection of data for the selected states.	✓ Data analysis – last 5 year information to understand impact of external factors in tariffs ✓ Sensitivity analysis	✓ Discussions with SERCs on the various analysis conducted. ✓ Preparation of draft report	✓ Finalization of report in consultation with FOR ✓ Dissemination workshop

Thank You

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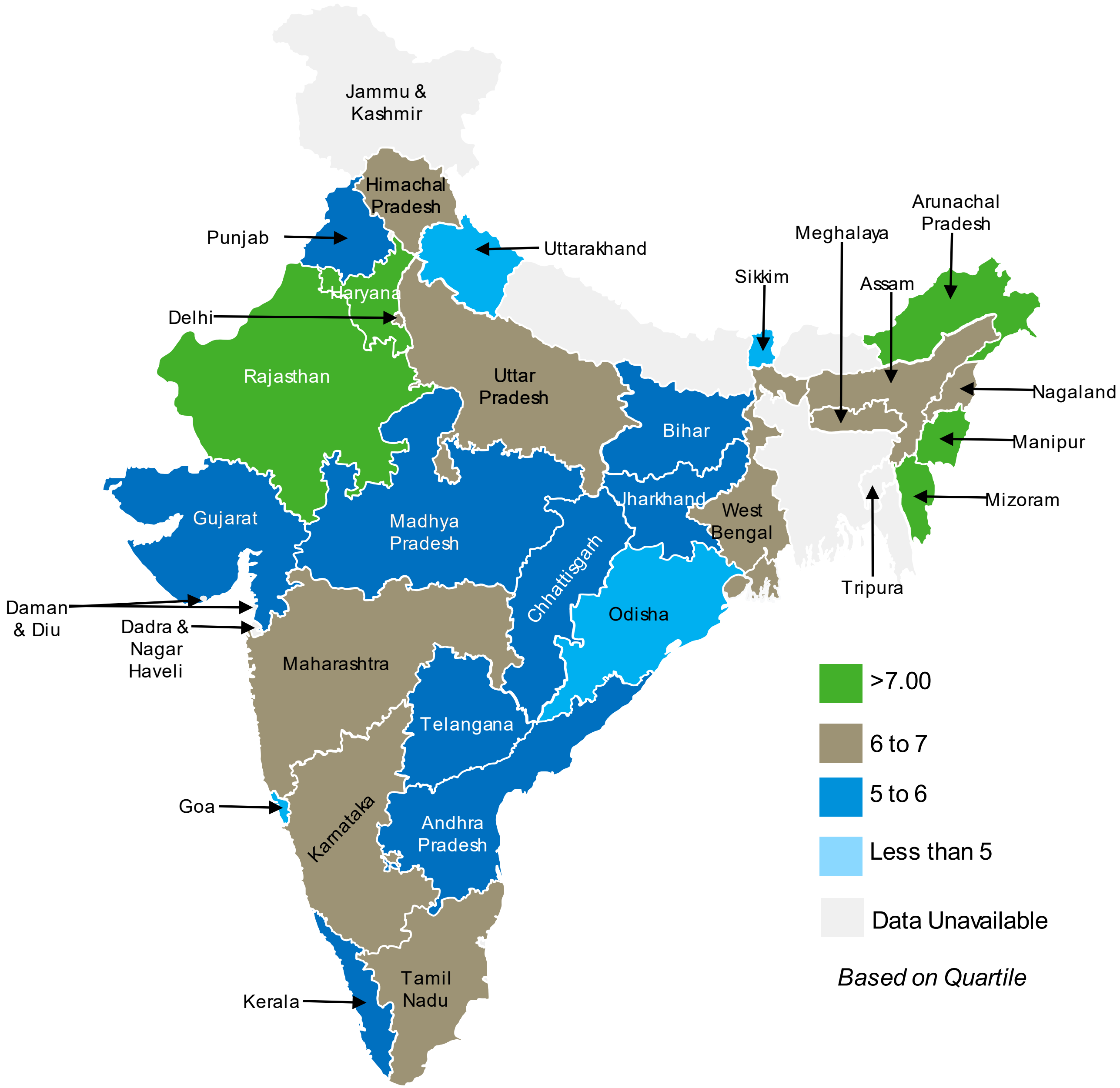
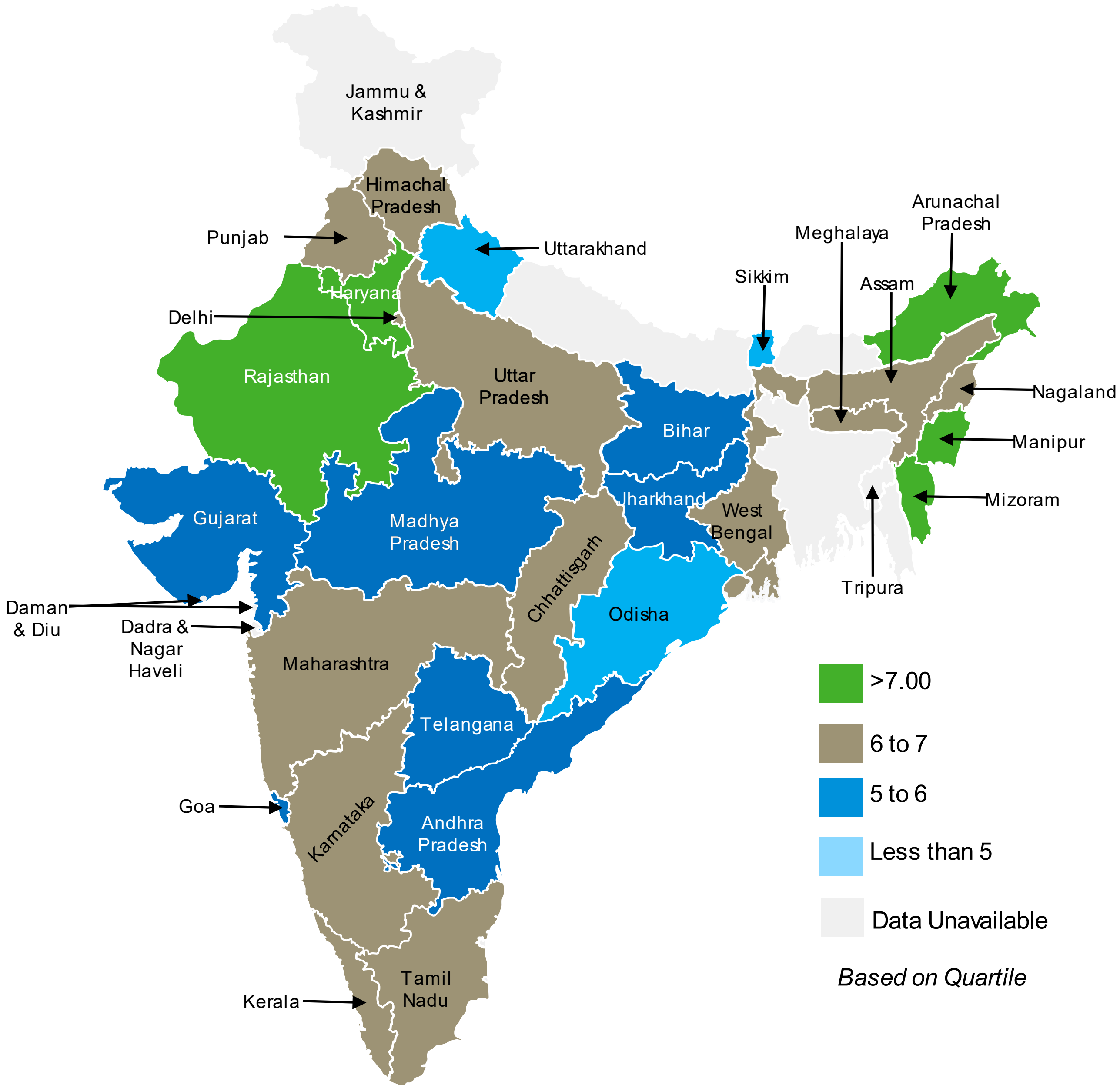
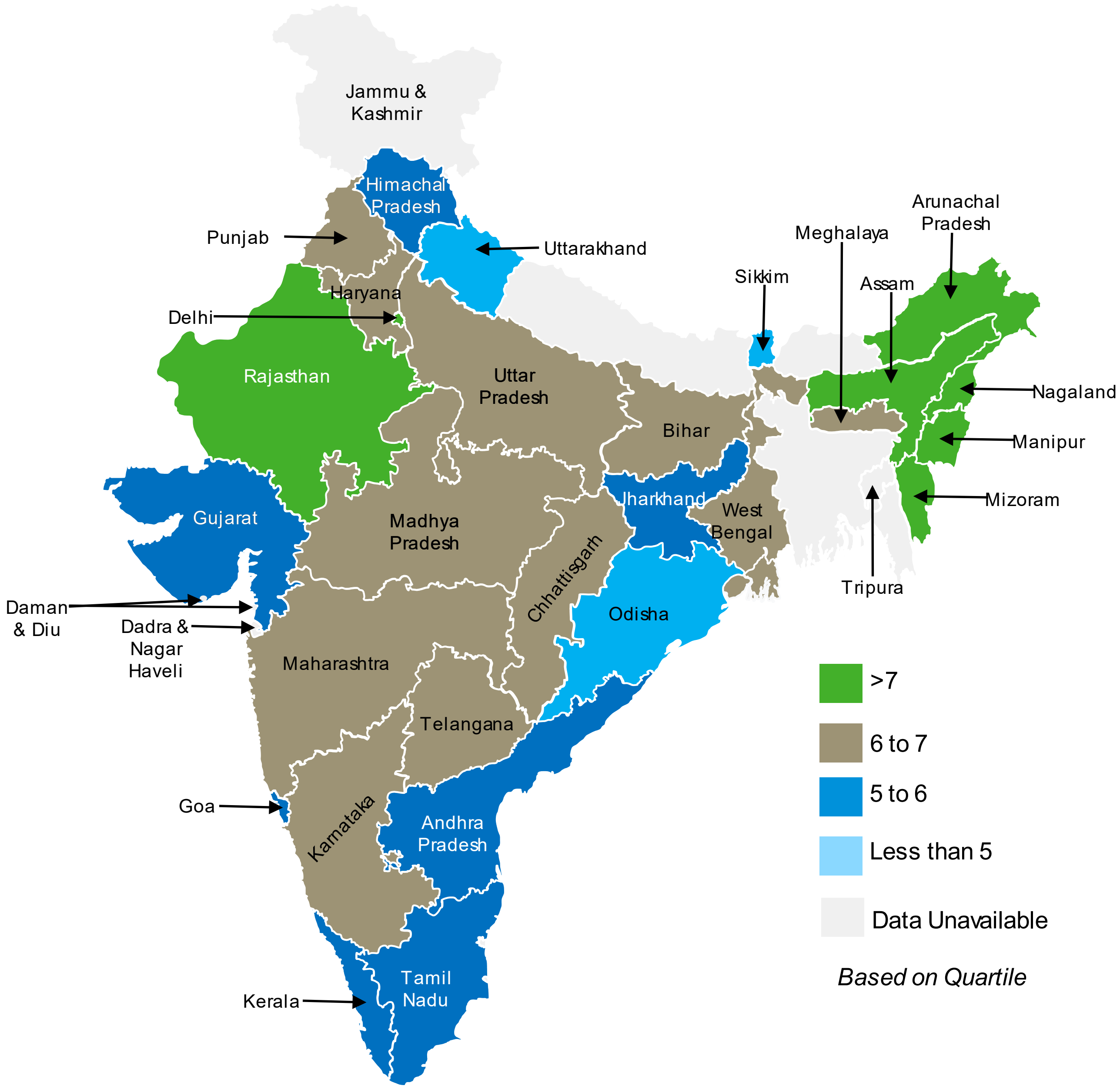
Average Cost of Supply (ACOS) for FY16



Average Cost of Supply (ACOS) for FY17



Average Cost of Supply (ACOS) for FY18



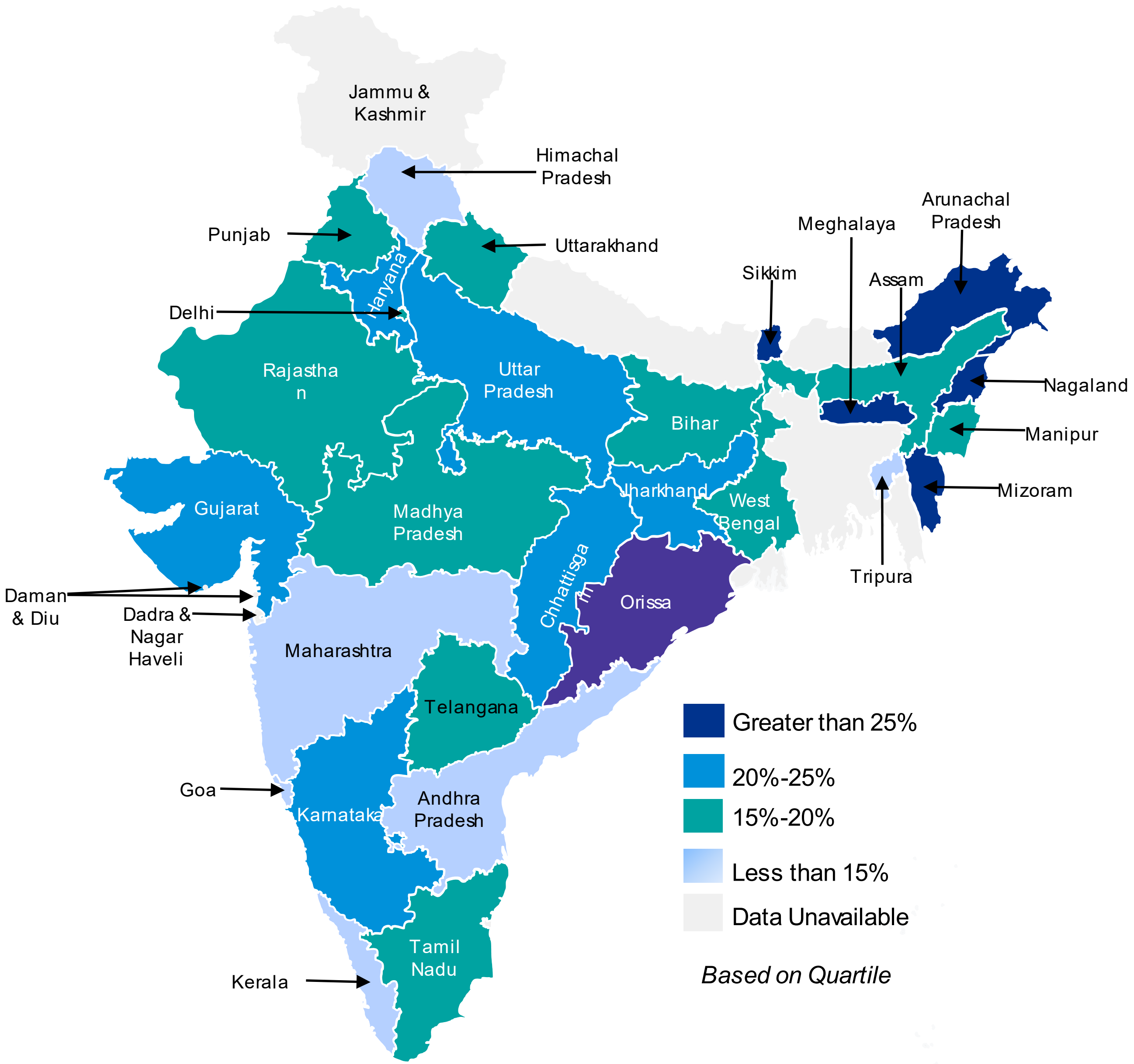
Key Observations

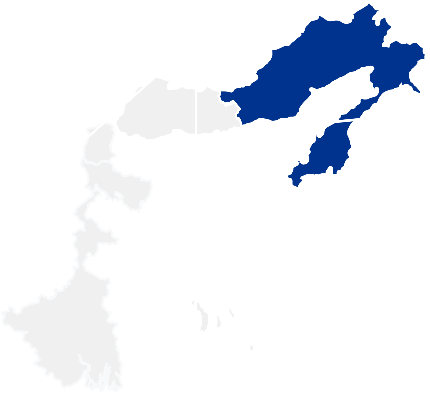
1. 4 states (Haryana, Rajasthan, Gujarat & TN) have witnessed a reduction in ACoS in the last 2 years (mainly due to better PP planning)

2. 3 states (Uttarakhand, Odisha & Sikkim) have maintained a low ACoS (< Rs 5/kWh) consistently over last 3 years

3. ACoS for Rajasthan & N/E states remined >Rs 7/kWh consistently during last 3 years

Distribution Losses for FY16





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15%

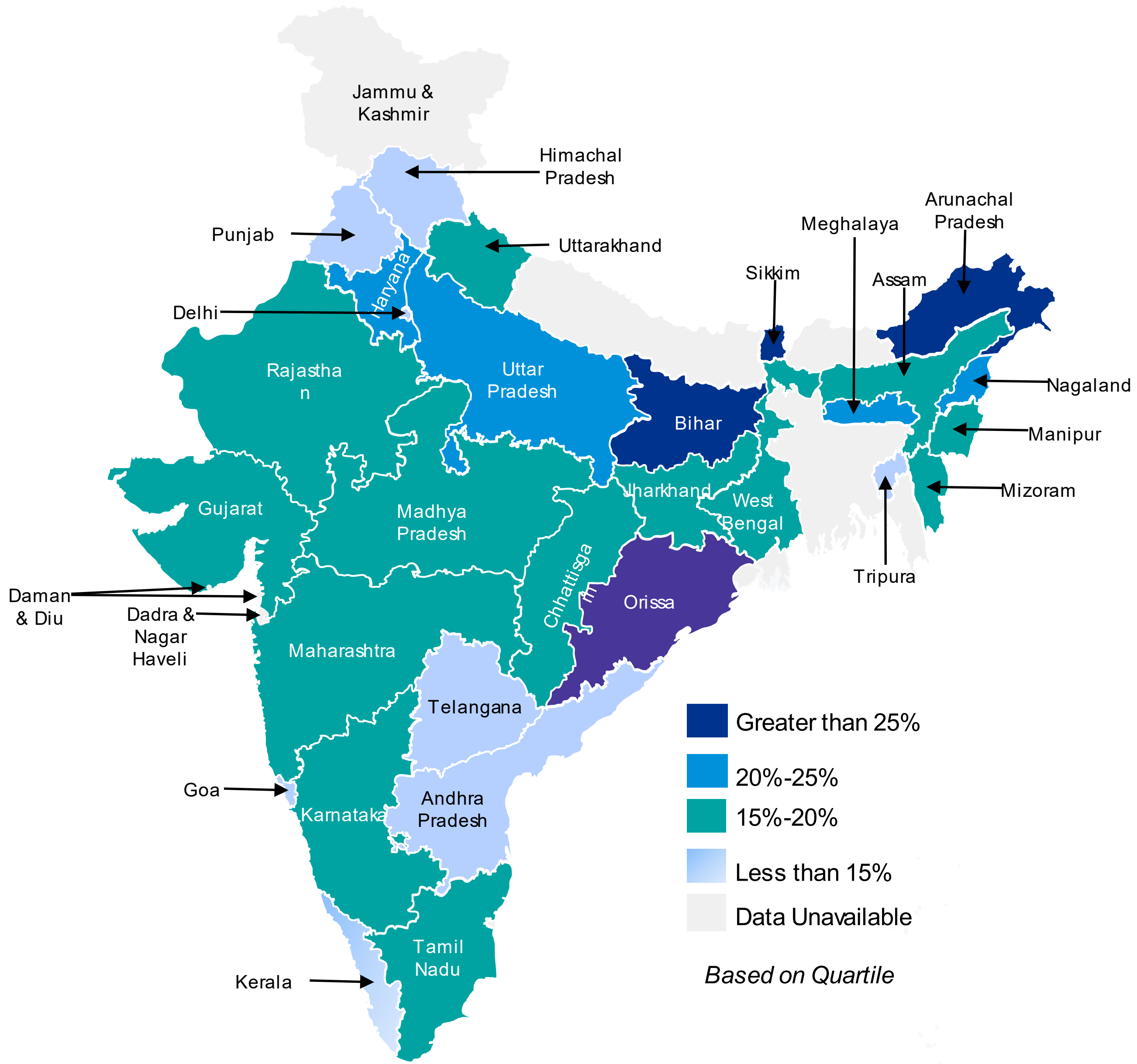
Data Unav

-

20%

Greater than 25%

Distribution Losses for FY18



Key Observations

1. Only 6 out of 29 states have distribution losses of less than 15% in FY18
2. Among large states, Bihar has witnessed highest increase in distribution losses in FY18 (~11%) possibly on account of electrification of rural households in the state.
3. States like Maharashtra, Uttarakhand and H.P have also reported increase (1-3%) in the distribution losses (FY-16 to FY-18)

Annexure-VII

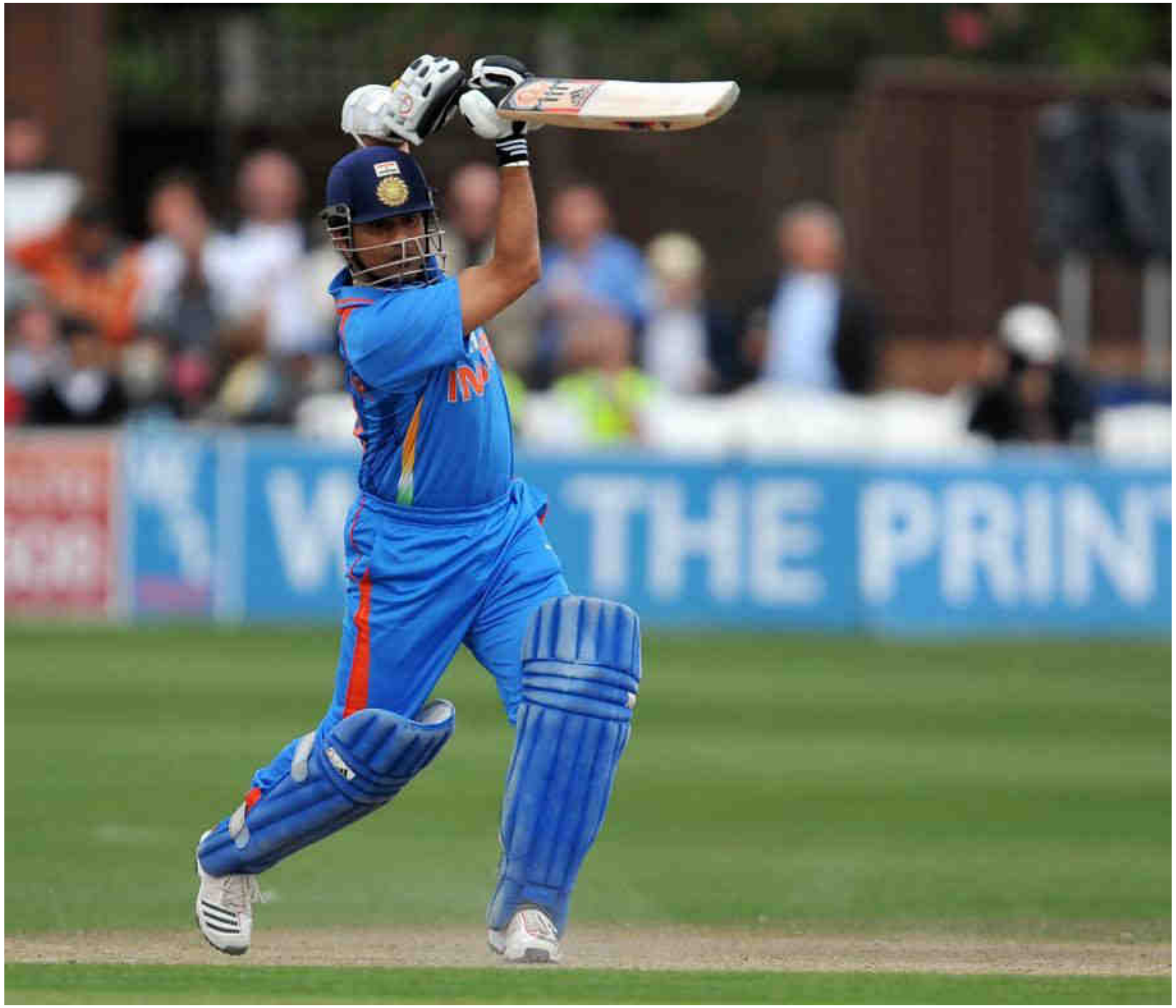
Sl. No.	Particulars	2015-16	2016-17	2017-18	2018-19
	State Electricity Regulatory Commission (SERC)				
	Format for compilation of data regarding the directions given by APTEL through its judgement dated 11.11.2011				
	I. Timeliness of Tariff Determination Process				
	A. Tariff Filing				
1	Whether timeline for filing petitions for Annual Performance Review (APR), true up of past expenses, Average Revenue Requirement (ARR) and Tariff Order specified in Tariff Regulations (Yes/No and also please mention the timelines)?				
	i. APR				
	ii. True Up				
	iii. ARR				
	iv. Tariff Order				
2	If yes, whether Annual Performance Review (APR), true up of past expenses, Average Revenue Requirement (ARR) and Tariff Order are being filed as per the requirements of regulation (please also provide the date of filing)?				
	i. APR				
	ii. True Up				
	iii. ARR				
	iv. Tariff Order				
3	If delay in filing of Annual Performance Review (APR), true up of past expenses, Average Revenue Requirement (ARR) and Tariff Order is beyond one month, whether the Regulatory Commission has taken any suo-motu action for determination of tariff? If not, please provide the reasons thereof				
	i. APR				
	ii. True Up				
	iii. ARR				

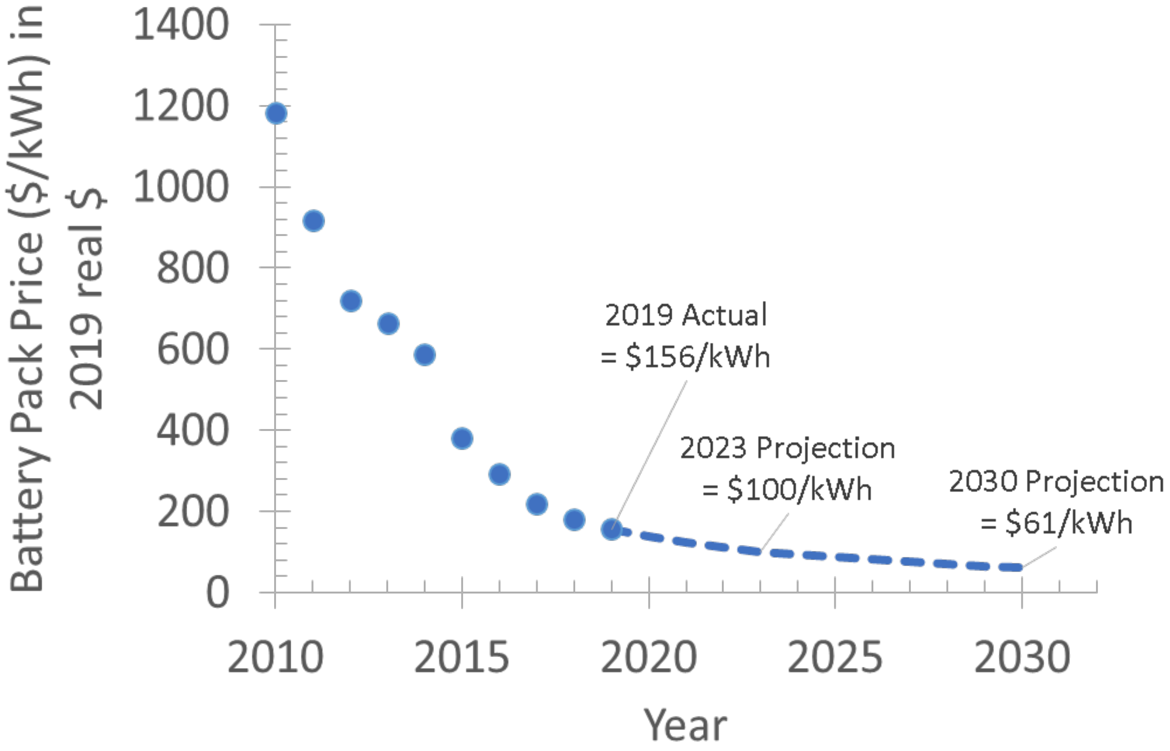
	iv. Tariff Order				
B. Tariff Order					
4	Whether Annual Performance Review (APR), true up of past expenses, Average Revenue Requirement (ARR) and Tariff Orders are being issued regularly within the time specified in accordance with the Act (please indicate the date of tariff petition and date of tariff order)?				
	i. APR				
	ii. True Up				
	iii. ARR				
	iv. Tariff Order				
5	Whether the applicability of Tariff is till the end of the financial year (Yes/No)?				
1	Annual Revenue Requirement (in Rs. Cr.)				
2	Saleable Energy (in MUs)				
3	Average Cost of Supply (Rs./kWh)				
4	Average Tariff (Rs./kWh)*				
5	Revenue gap between ARR and ACS per unit of only the year in consideration (in Rs./kWh)				
6	Whether Regulatory Assets have been created?				
7	If yes, whether the creation of Regulatory Assets is in line with the National Tariff Policy?				

8	Whether a roadmap (in terms of timeline not exceeding 3 years) for the recovery of such Regulatory Assets been specified?				
9	Whether carrying cost of the Regulatory Asset allowed to the utilities in the ARR of the year in which the Regulatory Assets are created?				
III.	Fuel & Power Purchase Cost Adjustment				
1	Whether Fuel Surcharge Adjustment formula/mechanism provided in regulation (Yes/No)?				
2	Frequency of adjustment of Fuel Surcharge as per the regulations (monthly/ bi-monthly/quarterly)?				
3	Fuel Surcharge Adjustment being done as per the regulations? If not, please provide the reasons thereof.				

Annexure-VIII

It is all about timing !





Globally, storage prices have dropped by ~90% over the last 10 years.

By FY 2025, Solar with 30% battery storage would cost ~Rs 3.5/kWh, nominally flat for 20 yrs.

Outline

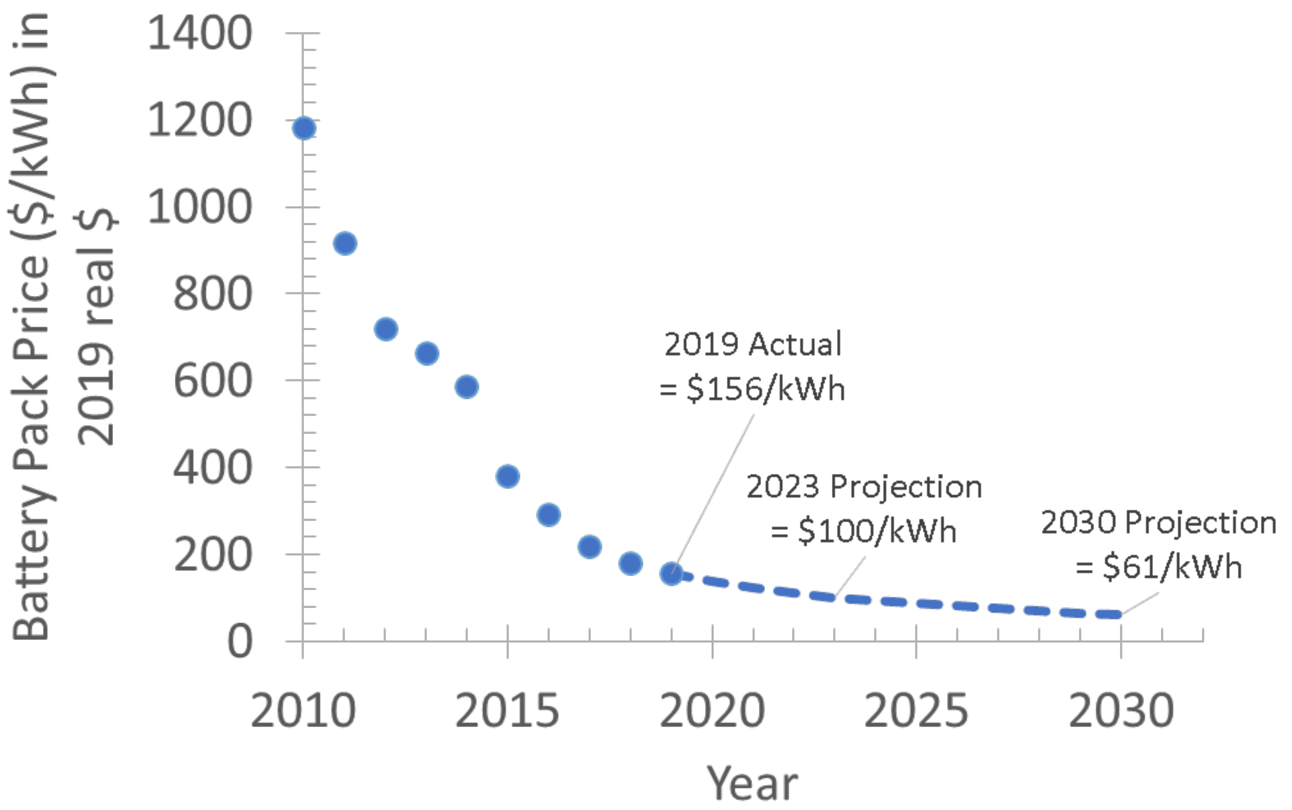
- Utility-scale storage: Overview of the recent developments in the US and India

- Economics of Battery Storage in India
  - What should be the price benchmarks in India ?
  - Would battery storage help grid operations and investment planning ?

- Regulatory Framework
  - Regulatory framework in the US
  - Key considerations for India

Overview of the recent developments

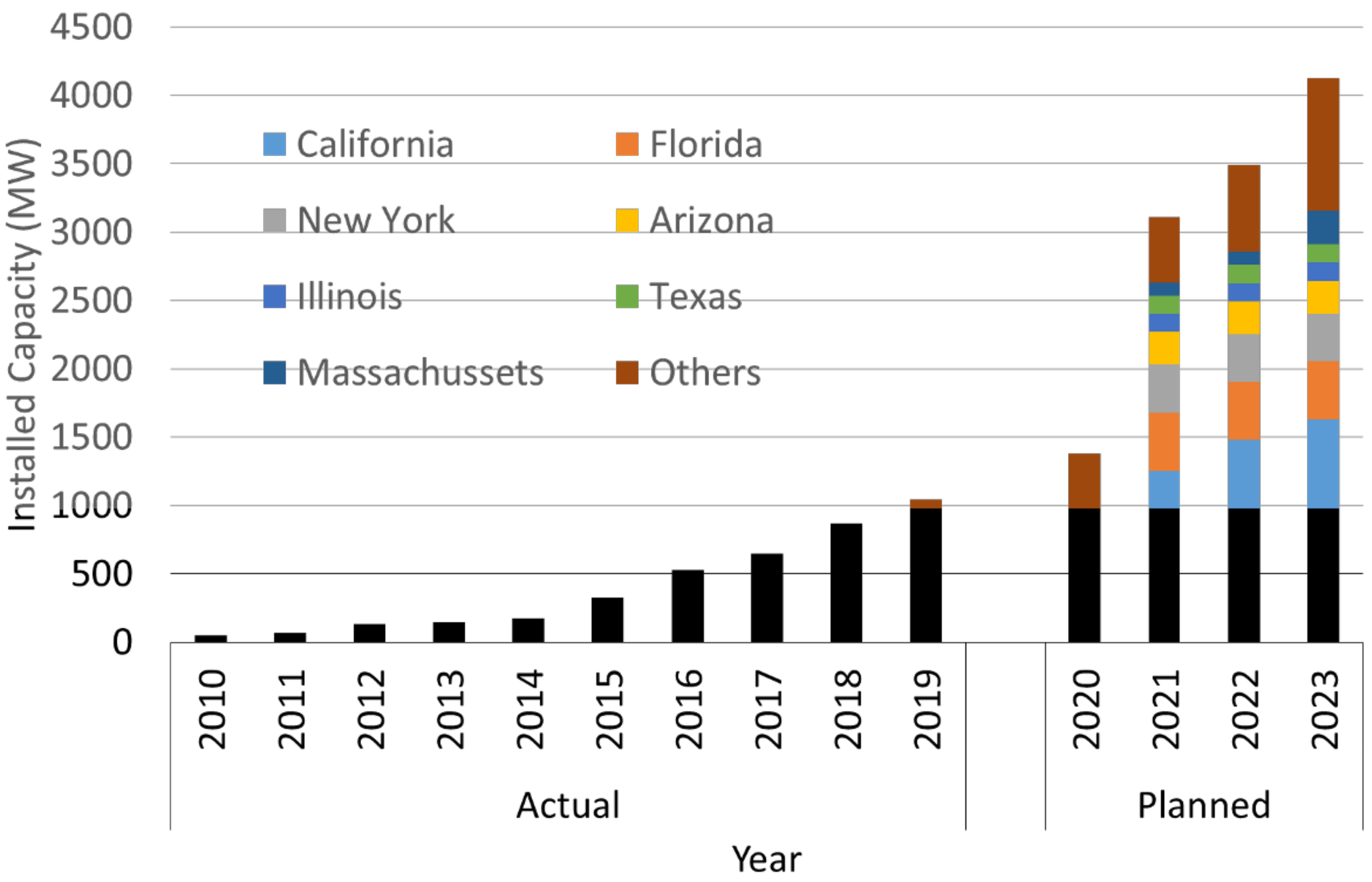
Battery prices have dropped by over 80-90% since 2010



Data source: BNEF 2019 Battery Price Survey

- Weight and size are not the primary constraints for grid scale batteries implying they could be cheaper
- Recent bids in the US: ~$33/MWh for solar + storage – equivalent to Rs 2.3/kWh
  ~$12/kW/month for standalone storage (6.5 hours) – equivalent to ~Rs 5/kWh

Battery storage installations have surged in the US – mostly driven by falling costs, high RE penetration, and regulatory support



Data source: US EIA for 860m (September 2019)

e.g. California

California has a storage procurement mandate of 1,300MW by 2020 plus additional 500MW of distributed storage by 2024

California also has one of the highest RE penetrations
 - 33% RPS by 2020 (already achieved)
- 60% RPS by 2030 (on-track to achieve before 2030)
- 100% Carbon-free by 2045

State	Project: Name	Project: Sponsor	Project: Offtaker	Actual or Expected COD (PV/Wind/Battery)	Capacity (MW-AC): PV	Capacity (MW-AC): Wind	Capacity (MW-AC): Battery	Battery Storage: Hours	Battery Storage: MWh	Battery:PV Capacity Ratio	Levelized PPA Price (2018 $/MWh)
AL	Redstone Arsenal	SunPower	Redstone Arsenal	Dec-17	10	0	1	2.0	2	10%	?
AR	Searcy	NextEra	Entergy (owner)	Dec-21	100	0	30	?	?	30%	#N/A
AZ	Pinal Central	NextEra	SRP	Apr-18	20	0	10	4.0	40	50%	68.9
AZ	Wilmot	NextEra	TEP	Dec-19	100	0	30	4.0	120	30%	40.7
AZ	Redhawk(?)	First Solar	APS	Jun-21	65	0	50	2.7	135	77%	?
CA	Desert Harvest II	EDF-RE	SCPPA	Dec-20	70	0	35	4.0	140	50%	LMP plus $15.25
CA	RE Slate 2	ReCurrent	MBCP and SVCE	Jun-21	150	0	45	4.0	180	30%	≤31.8
CA	BigBeau	EDF-RE	MBCP and SVCE	Dec-21	128	0	40	4.0	160	31%	≤30.9
CA	?	NextEra	Kaiser Permanente	Dec-20/Dec-21/Dec-21	131	50	110	?	?	84%	?
CA	Sonrisa	EDPR	SJCE & EBCE	Dec-22	200	0	40	4.0	160	20%	?
CA	Raceway	sPower	EBCE	Dec-22	125	0	80	2.0	160	64%	?
CA	Eland	8minute Solar	LADWP/Glendale	Dec-23	400	0	300	4.0	1200	75%	28.5
FL	Babcock	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	10	4.0	40	13%	#N/A
FL	Citrus	NextEra	FPL (owner)	Dec-16/NA/Mar-18	74.5	0	4	4.0	16	5%	#N/A
FL	Manatee	NextEra/FPL	FPL (owner)	Dec-16/NA/Dec-21	74.5	0	409	2.2	900	549%	#N/A
HI	Kapaia	Tesla	KIUC	Apr-17	13	0	13	4.0	52	100%	119.8
HI	Lawai	AES	KIUC	Oct-18	20	0	20	5.0	100	100%	89.4
HI	Kekaha	AES	KIUC	Sep-19	14	0	14	5.0	70	100%	85.5
HI	West Loch	HECO	HECO (owner)	Oct-19	20	0	20	4.0	80	100%	#N/A
HI	Waikoloa Solar	AES	Hawaiin Electric	Jul-21	30	0	30	4.0	120	100%	59.8
HI	Kuihelani Solar	AES	Hawaiin Electric	Jul-21	60	0	60	4.0	240	100%	58.5
HI	West Oahu	AES	Hawaiin Electric	Sep-21	12.5	0	12.5	4.0	50	100%	79.5
HI	Hoohana Solar 1	174 Power Global	Hawaiin Electric	Dec-21	52	0	52	4.0	208	100%	76.3
HI	Mililani I Solar	Clearway	Hawaiin Electric	Dec-21	39	0	39	4.0	156	100%	68.0
HI	Waiawa Solar	Clearway	Hawaiin Electric	Dec-21	36	0	36	4.0	144	100%	74.0
HI	Hale Kuawehi	Innergex	Hawaiin Electric	Jun-22	30	0	30	4.0	120	100%	65.8
HI	Paeahu	Innergex	Hawaiin Electric	Jun-22	15	0	15	4.0	60	100%	87.9
MN	Ramsey/Athens	Engie/NextEra	Connexus	Dec-18	10	0	15	2.0	30	150%	?
NV	Battle Mountain	Cypress Creek	NV Energy	Jun-21	101	0	25	4.0	100	25%	22.3
NV	Dodge Flat	NextEra	NV Energy	Dec-21	200	0	50	4.0	200	25%	23.1
NV	Fish Springs Ranch	NextEra	NV Energy	Dec-21	100	0	25	4.0	100	25%	25.9
NV	Townsite	Capital Dynamics	Munis/Co-op	Dec-21	180	0	90	4.0	360	50%	?
NV	Arrow Canyon	EDF-RE	NV Energy	Dec-22	200	0	75	5.0	375	38%	21.8
NV	Southern Bighorn	8minute Solar	NV Energy	Sep-23	300	0	135	4.0	540	45%	21.9
NV	Gemini	Quinbrook/Arevia	NV Energy	Dec-23	690	0	380	3.8	1460	55%	25.1
OK	Skeleton Creek	NextEra	WFEC	Dec-23/Dec-19/Dec-23	250	250	200	4.0	800	80%	?
OR	Wheatridge	NextEra	PGE	Dec-21/Dec-20/Dec-21	50	300	30	4.0	120	60%	?
TX	Castle Gap	Luminant	Luminant (owner)	Jun-18/NA/Dec-18	180	0	10	4.2	42	6%	#N/A

Solar + Storage is emerging as a new normal

Solar + 4-hr Storage @ 25% capacity delivered at 3c/kWh (~Rs 2.1/kWh) unsubsidized by 2021

Source: Bolinger et. al 2019, LBNL

BRIEF

Storage will replace 3 California gas plants as PG&E nabs approval for world's largest batteries

AUTHOR
Gavin Bade
@GavinBade

PUBLISHED
Nov. 9, 2018

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Dive Brief:

- The California Public Utilities Commission on Thursday approved four energy storage projects for Pacific Gas & Electric (PG&E) to replace retiring gas generators, including two batteries that would be the largest in the world.
- The CPUC granted approval for a total of 567.5 MW / 2,270 MWh of storage, including a 300 MW / 1,200 MWh project from Vistra Energy and a 182.5 MW / 730 MWh project from Tesla that the utility would own. Those batteries, once completed, would be the two largest in service.
- The CPUC directed PG&E to purchase the storage in January instead of approving new ratepayer-funded contracts for three gas plants in PG&E's service area. Analysts told Utility Dive the cost of the batteries is likely cheaper than continuing to operate the plants.

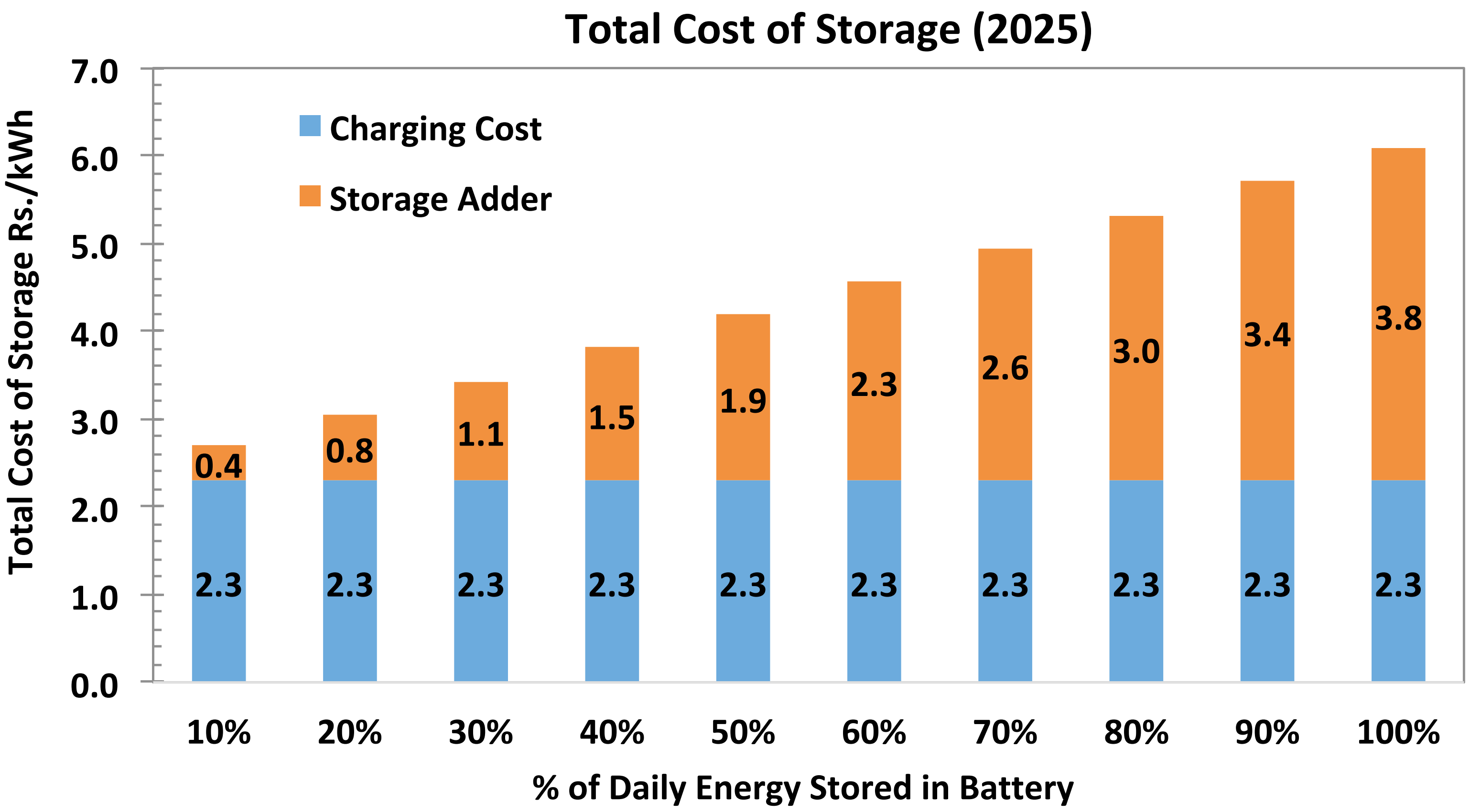
Most recent solar + 4-hr storage PPA = 3.3 cents/kWh (LADWP Eland)

	Eland Phase 1	Eland Phase 2
Solar Technology	Single Axis Tracking Solar PV	
Term	25 Years	
Total Capacity	200 MW	
Solar Price	$19.97/MWh	
BESS Size	100MW/4-hour (400MWh)	
BESS Price Adder	$13.00/MWh	
LADWP Share:	87.5%	100.0%
Glendale Share	12.5%	N/A
RPS % in 2025	3.1%	3.5%
Early Buyout Option (EBO)	15, 20, and 25 year anniversary of Commercial Operation Date	
EBO price	Based on Fair Market Price	

How much would battery storage cost in India?

Standalone Storage (1 MW / 4 MWh system)

	FY 2020	FY 2025	FY 2030
Battery Pack ($/kWh)	143	88	62
Inverter + Balance of System ($/kWh)	39	30	26
EPC + Soft Costs ($/kWh)	21	16	15
Total capital cost ($/kWh)	203	134	103



In FY 2025, for storing 40% of daily solar PV energy (i.e. 4-hours of storage at 50% of rated solar capacity), net storage adder would be ~Rs 1.5/kWh; by 2030, it would drop to ~Rs 1.3/kWh.
Note that this is project specific adder; fleet level adder would be much smaller. Also, these costs would be flat in nominal terms for 20-25 years.

Significant interest in utility-scale storage in India

- Procurement
  - SECI bid of 1200MW RE + 3600MWh of storage
  - MSEDCL bid of 500MW solar + storage
  - AP solar + wind + storage hybrid project (supported by The World Bank)

- Regulatory
  - CERC staff paper on storage; recognition of storage in connectivity regulations
  - Several SERCs are considering issuing regulations around battery storage (e.g. Rajasthan)

- Policy
  - MOP / ISGF issued report on the state of battery storage in India

Economics and operation of battery storage in India

Need / Value of Grid-Scale Energy Storage in India

- Effective alternative to thermal to meet shoulder demand
- Solar + storage as a short lead-time and modular option to deal with inherent uncertainty in demand
- Grid reliability – ancillary services – transmission congestion
- Nominally flat costs for the next 20-25 years
- Learning and future cost reduction

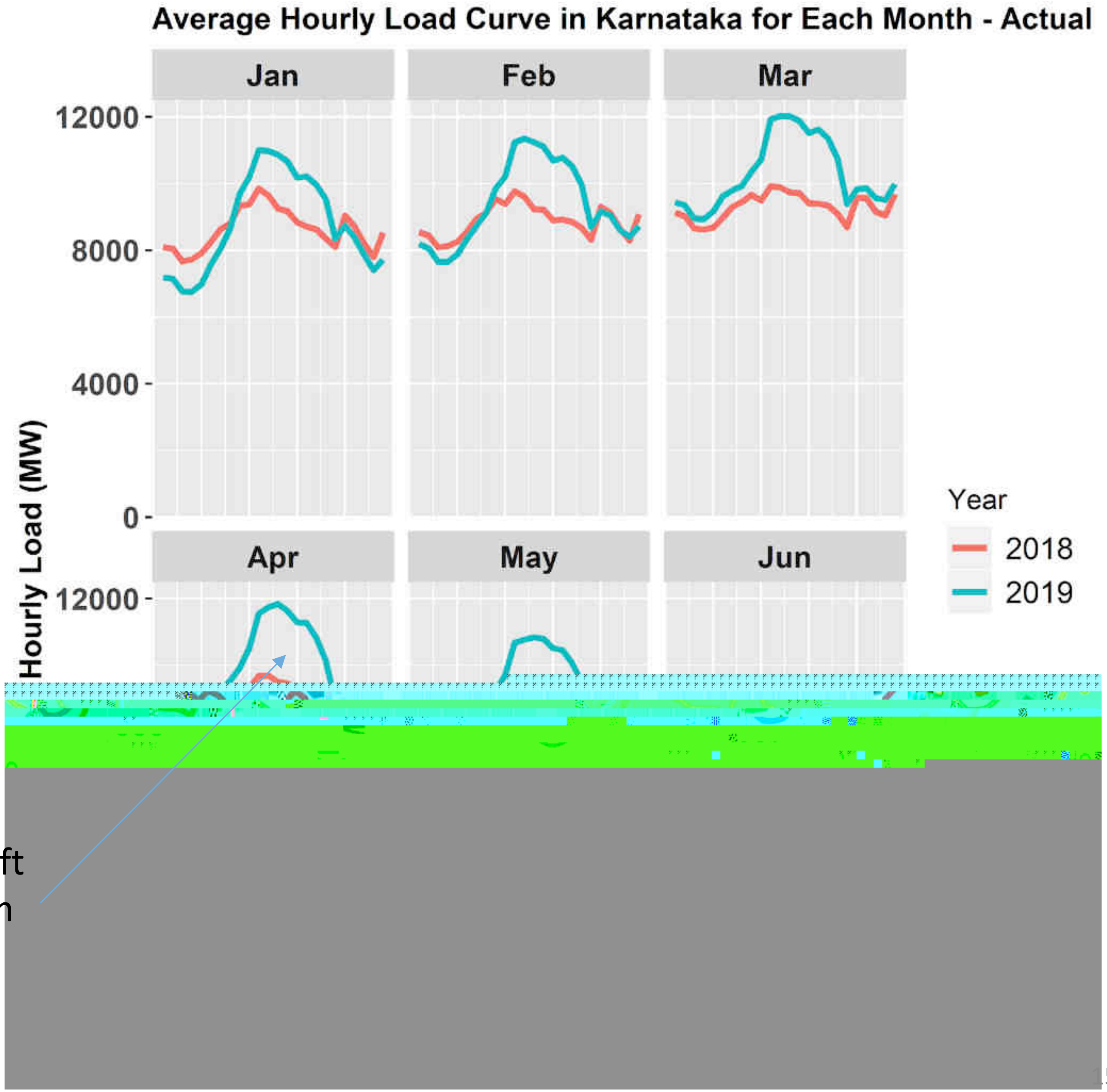
Let’s take example of Karnataka

	FY 2020 (Actual)	FY 2030 (Based on CEA forecast)
Peak Load (MW)	~13,000 (incl Ag Shift)	~22,000 (incl Ag shift)
Thermal capacity (incl CS) (MW)	~11,000	~18,000
Hydro (MW)	~3,500	~3,500
Wind (MW)	~5,000	~7,000
Solar (MW)	~6,500	~18,000
Agricultural Load Shift (MW)	~2,000	~3,000

Ag load shift to solar hours reduces the night time load significantly

Several states have already started doing that e.g. Karnataka, Maharashtra, MP etc.

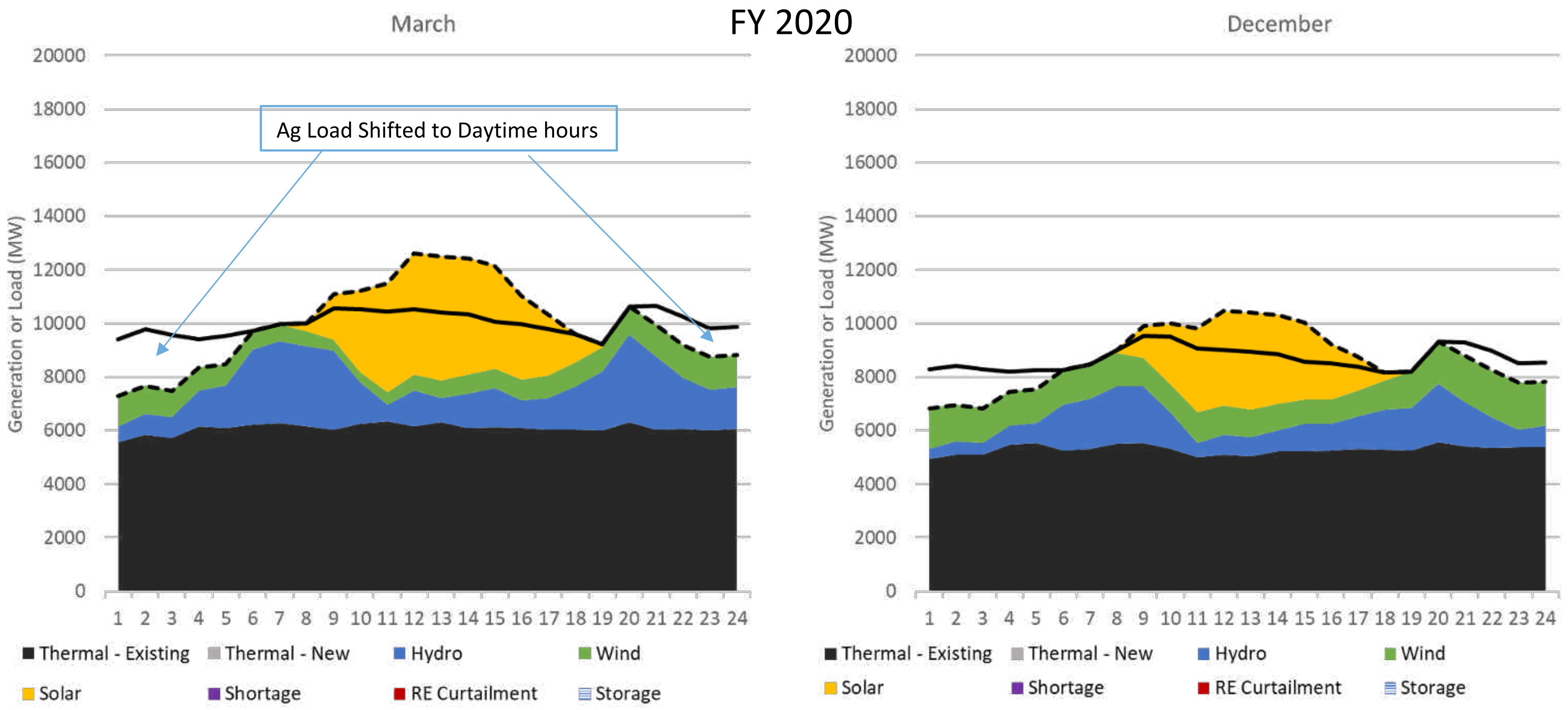
Chart shows actual Karnataka load data before (2018) and after (2019) the Ag load shift



With ~2,000 MW of Ag Load Shift to solar hours, Karnataka system peak load has already shifted to afternoon

Even today, significant backing down of thermal plants becomes necessary

Following charts show simulated hourly dispatch in Karnataka – in March and December



- Annual average thermal PLF < 50% ➔ causing stressed thermal assets

Let’s consider four pathways for Karnataka up to FY 2030:

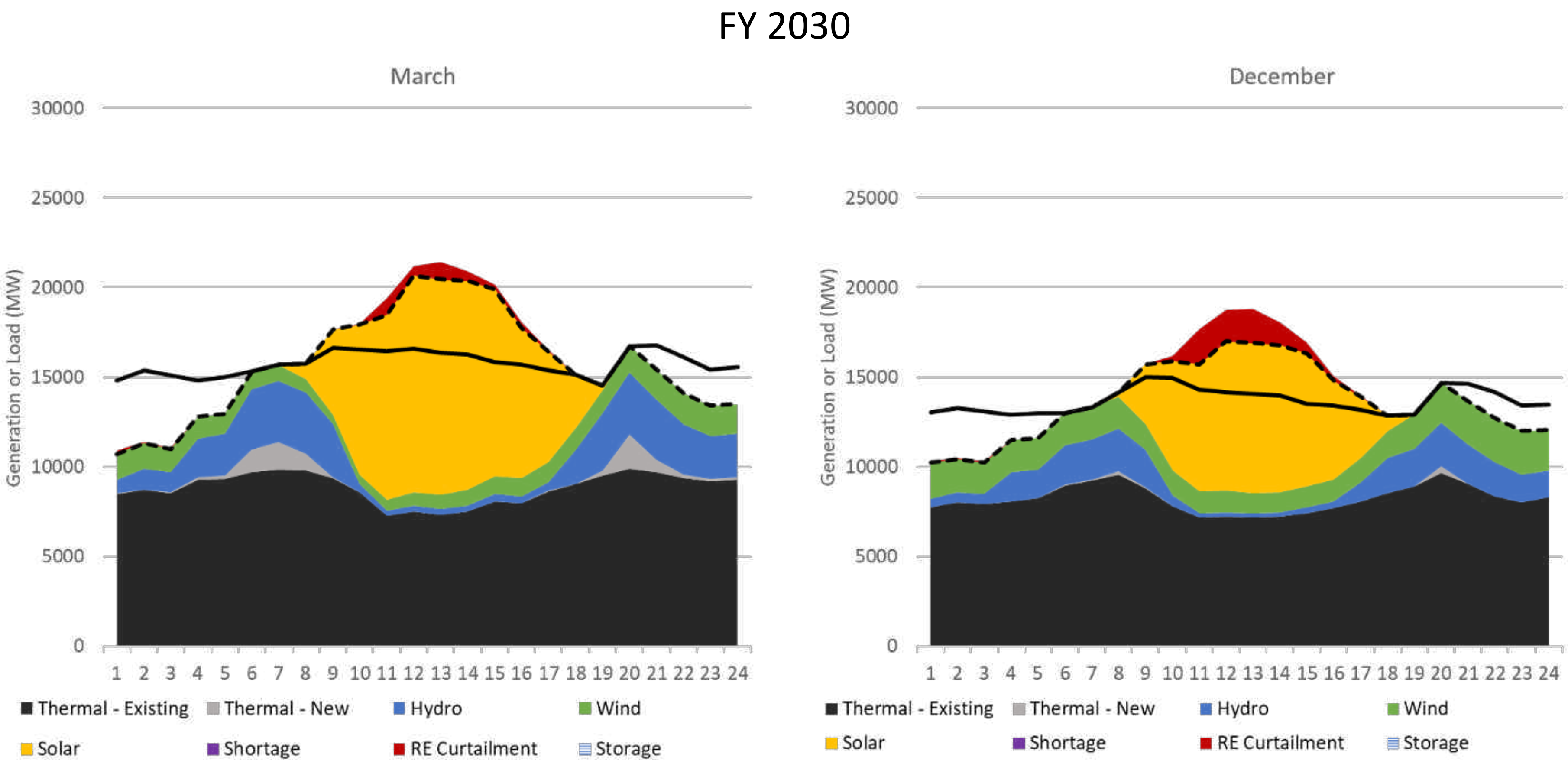
1. Current pattern continues − RE and Thermal additions go as projected
   - By 2030, RE = 25GW, Thermal = 18GW, Peak Load = 22GW

2. No new RE additions; only thermal additions in the future
   - By 2030, RE = 11GW, Thermal = 18GW, Peak Load = 22GW

3. No new thermal additions; only RE additions in the future
   - By 2030, RE = 25GW, Thermal = 11GW, Peak Load = 22GW

4. RE + some thermal additions with battery storage
   - By 2030, RE = 25GW, Thermal = TBD, Batteries = TBD, Peak Load = 22GW

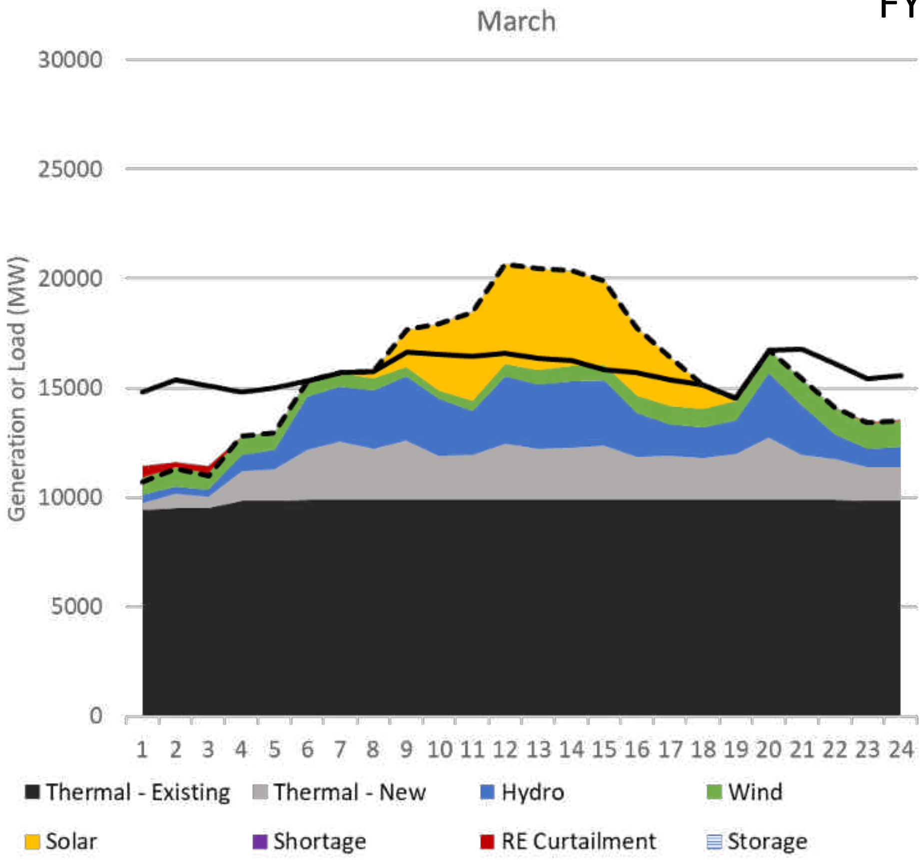
If RE and Thermal additions go as projected, RE and thermal both suffer

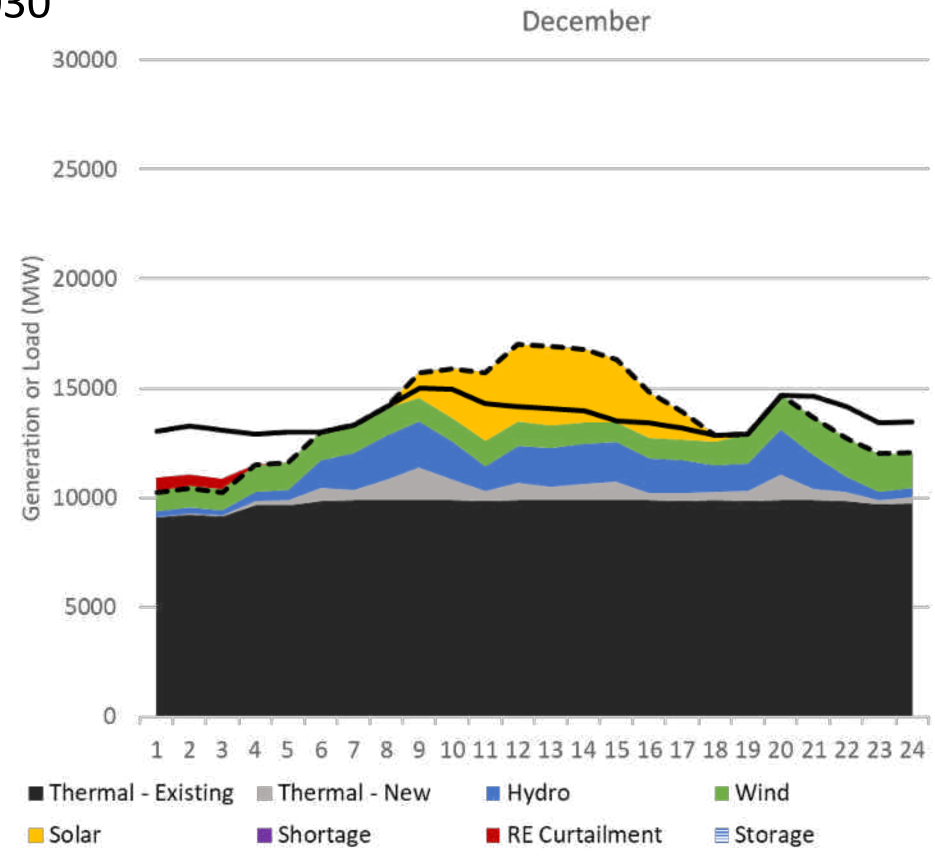


- Large RE curtailment becomes necessary (~20%) → making new RE investments very risky
- Out of 18GW of the projected thermal capacity, ~11GW will operate at ~80% PLF while ~7GW will operate at 10% - thereby seriously jeopardizing their cost-effectiveness

If new load is met just by building additional coal, the pathway becomes financially too risky

FY 2030

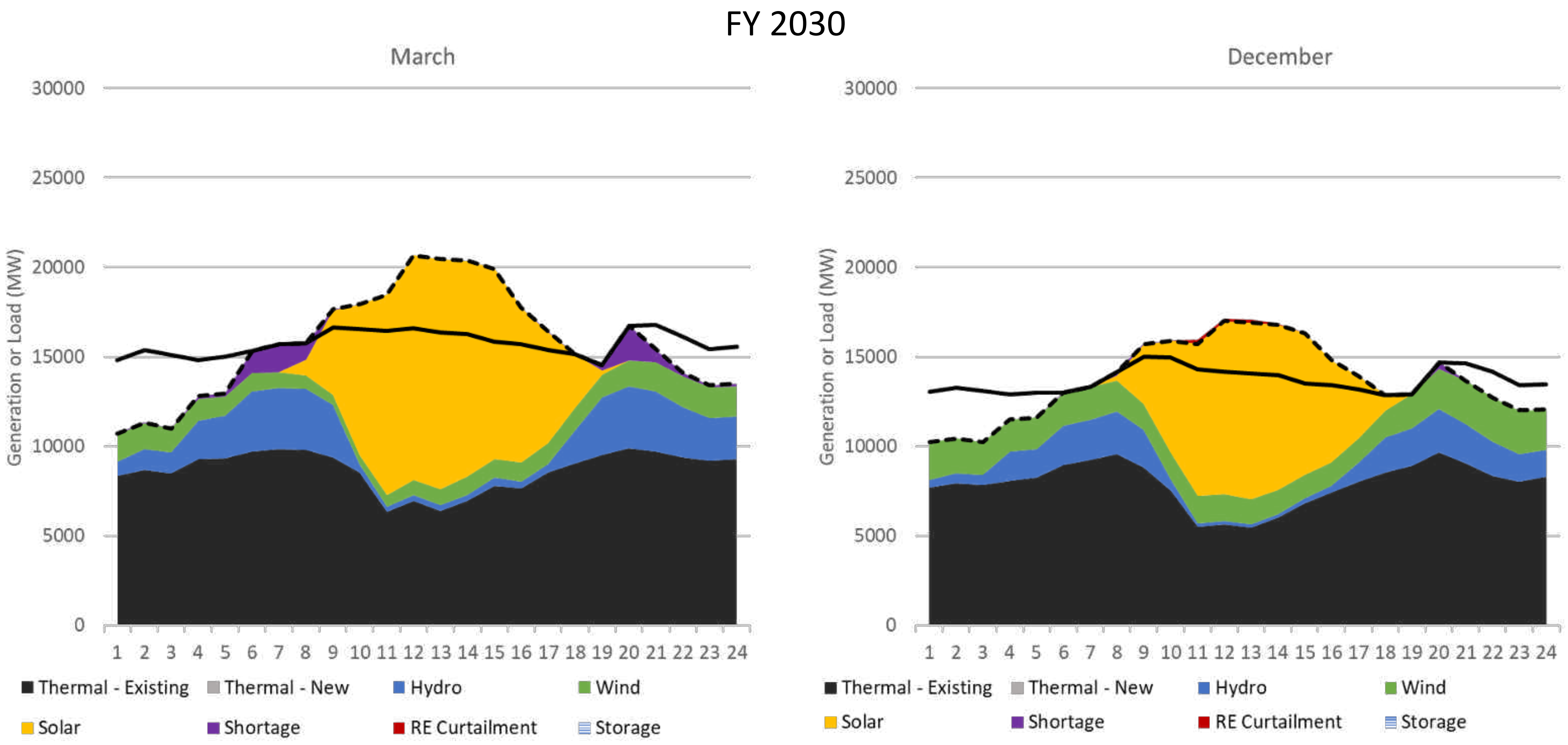




- Average Coal PLF ~60%
- ~11 GW coal operates at ~75% while ~7GW operates at ~20% PLF

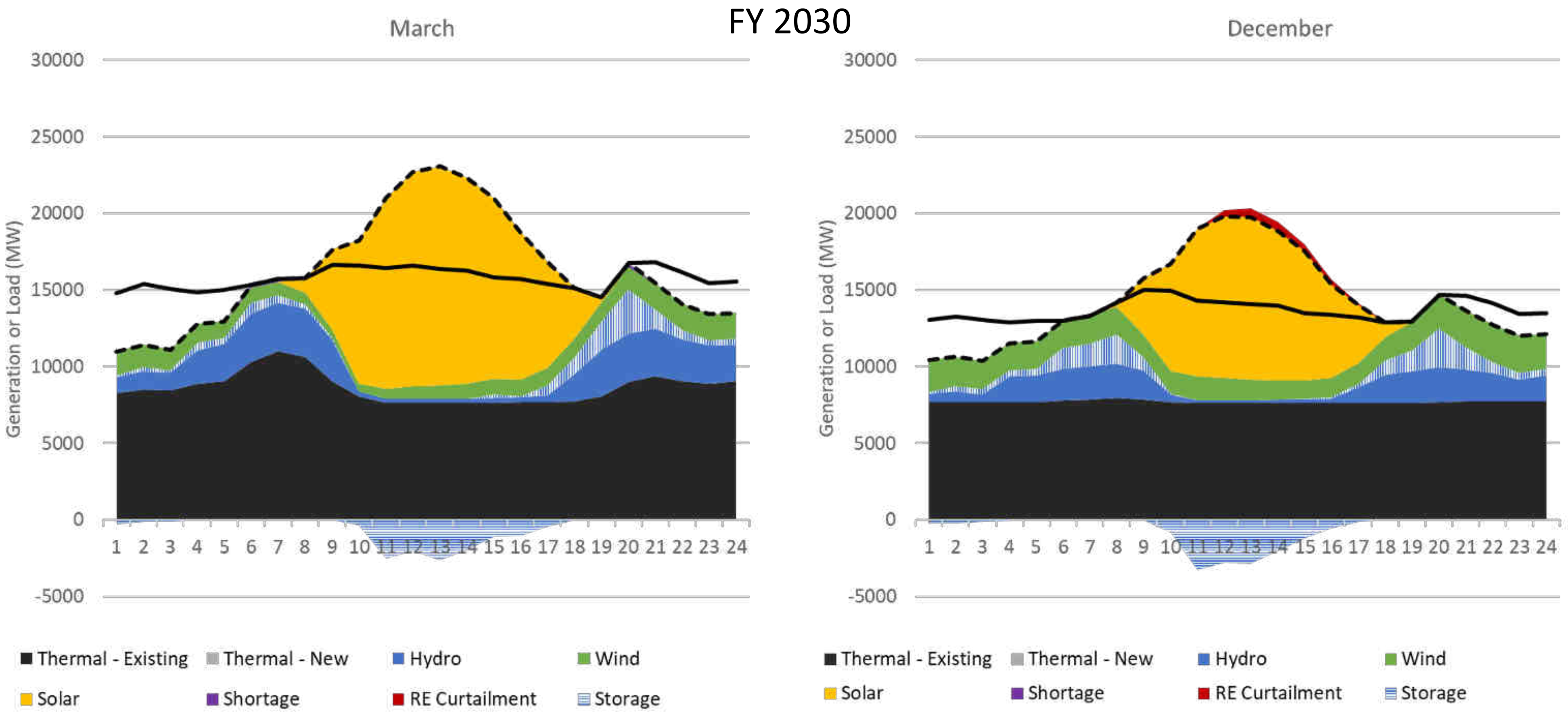
➔ By FY 2030, average coal power cost would reach ~ Rs 5-6/kWh, while solar and storage costs will likely be ~ Rs 2/kWh nominally fixed for 20-25 years

If no new thermal assets are built, peaking shortages develop



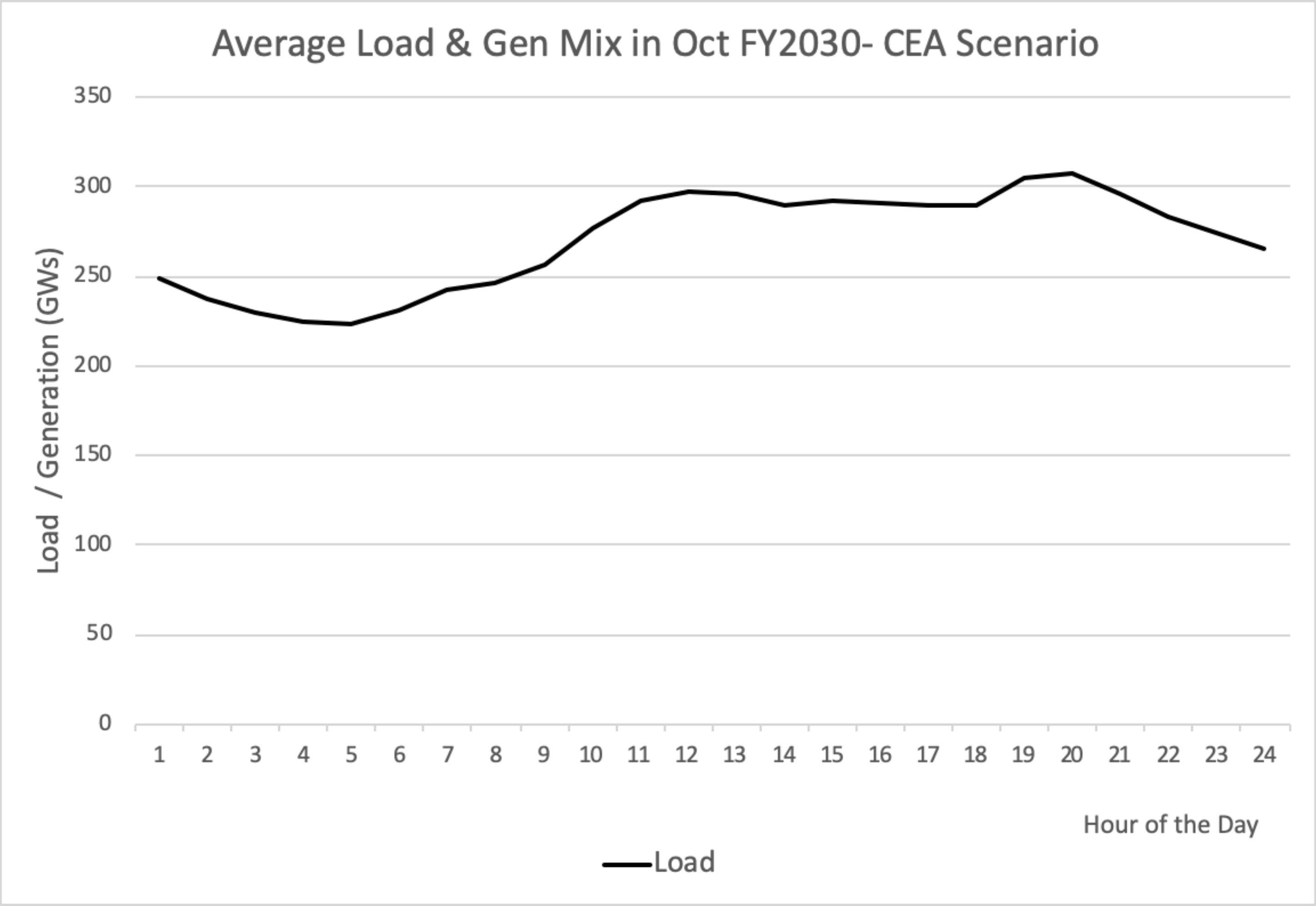
- RE alone will not be able to meet the morning and evening peak load – especially in spring / summer;
- Thermal / firm capacity will be required to meet the demand reliably

With energy storage, ~7 GW of stressed thermal investments could be avoided in KA



- Storage helps with efficient system dispatch and in avoiding ~7GW of inefficient thermal investments in KA by 2030
- ~12GWh of energy storage is required (~10% of daily RE generation) ➔ equivalent to ~3-4 GW of solar with 3-4 hours of storage each. Spread over entire RE generation, the net storage adder would be ~ Rs 0.5/kWh.

India’s projected electricity requirement ~2400 BUs by 2030

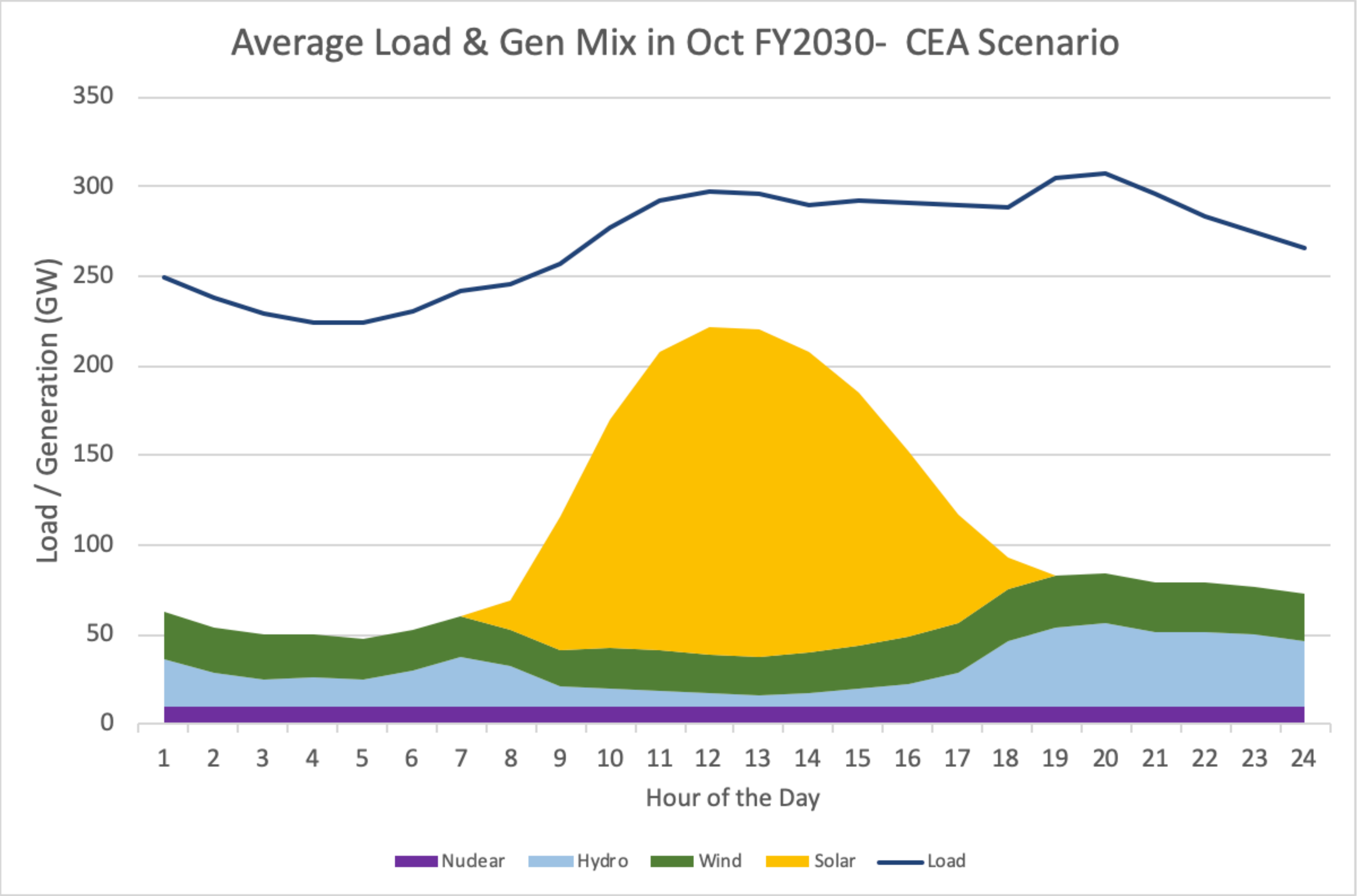


Peak requirement: 340 GW

Resource mix (as projected by CEA):

Coal	267 GW
Solar	300 GW
Wind	140 GW
Hydro	73 GW
Nuclear	16 GW

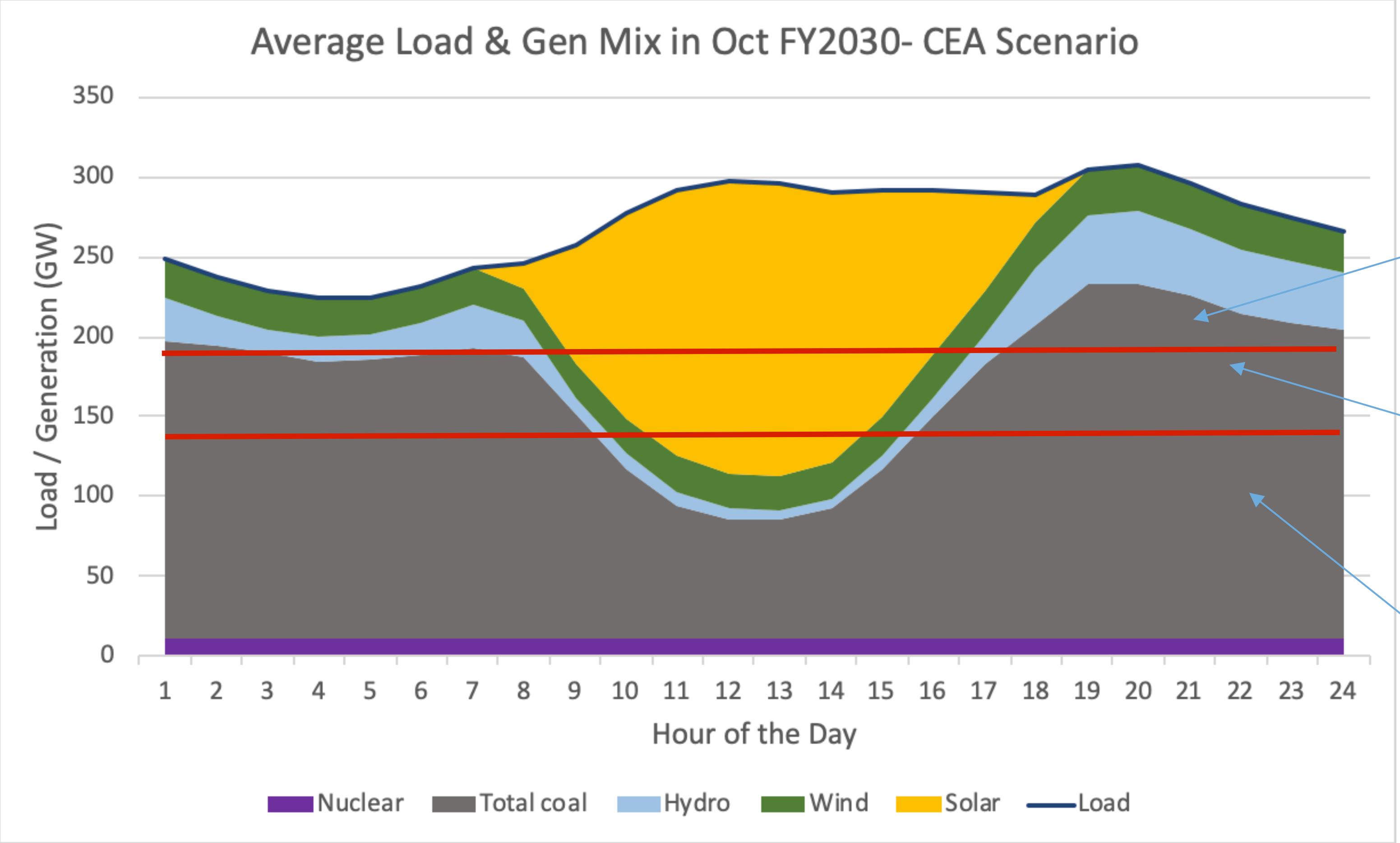
Large scale integration of RE will change how coal plants are run



Thermal plants will have to meet the

(Net Load = Load minus RE generation)

By 2030, Average Coal PLF may drop to ~56%



~60-70 GW operates at a capacity factor of 10-15% (peaking)

- Avg cost of generation = ~ Rs 10/kWh
- **Potentially stressed assets**

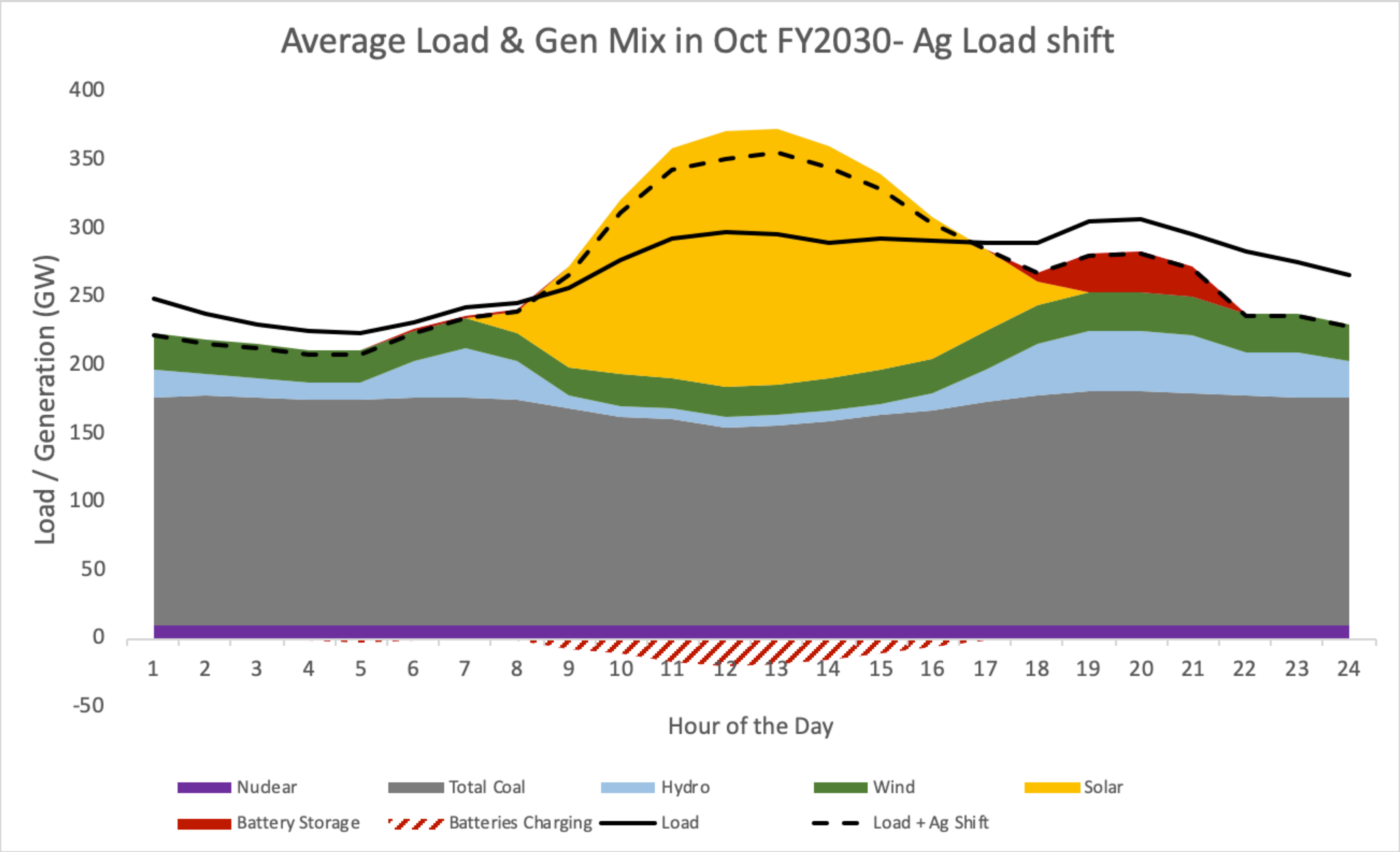
~50-60 GW operates at a capacity factor of ~40% (intermediate)

- Avg cost of generation = ~Rs 6/kWh
- **Potentially stressed assets**

~140-150 GW operates at a capacity factor of 80% (base load)

- Avg cost of generation = ~Rs 3.5/kWh

Ag load shift (for night time support) and Battery Storage (for evening peak) can avoid building of ~70GW of potentially stressed thermal assets, which are yet to be built



- 150 GW continues to operate at ~85% PLF
- PLF of next 50 GW is 36%.
-

⇒ **If Ag load shifts to solar hours, India can avoid building ~70 GW of potentially stressed thermal assets, that will be built beyond FY 2022**

Regulatory Framework

Big Picture…

- If low cost storage/ solar + storage (~ Rs 3-4/kWh) is realized in India it provides
  - Effective alternative for peak-intermediate load power – which is challenging to do with coal
  - Viable alternative fast response ancillary service
  - Fast deployment alternative to deal with uncertain demand that leads to shortage or overcapacity

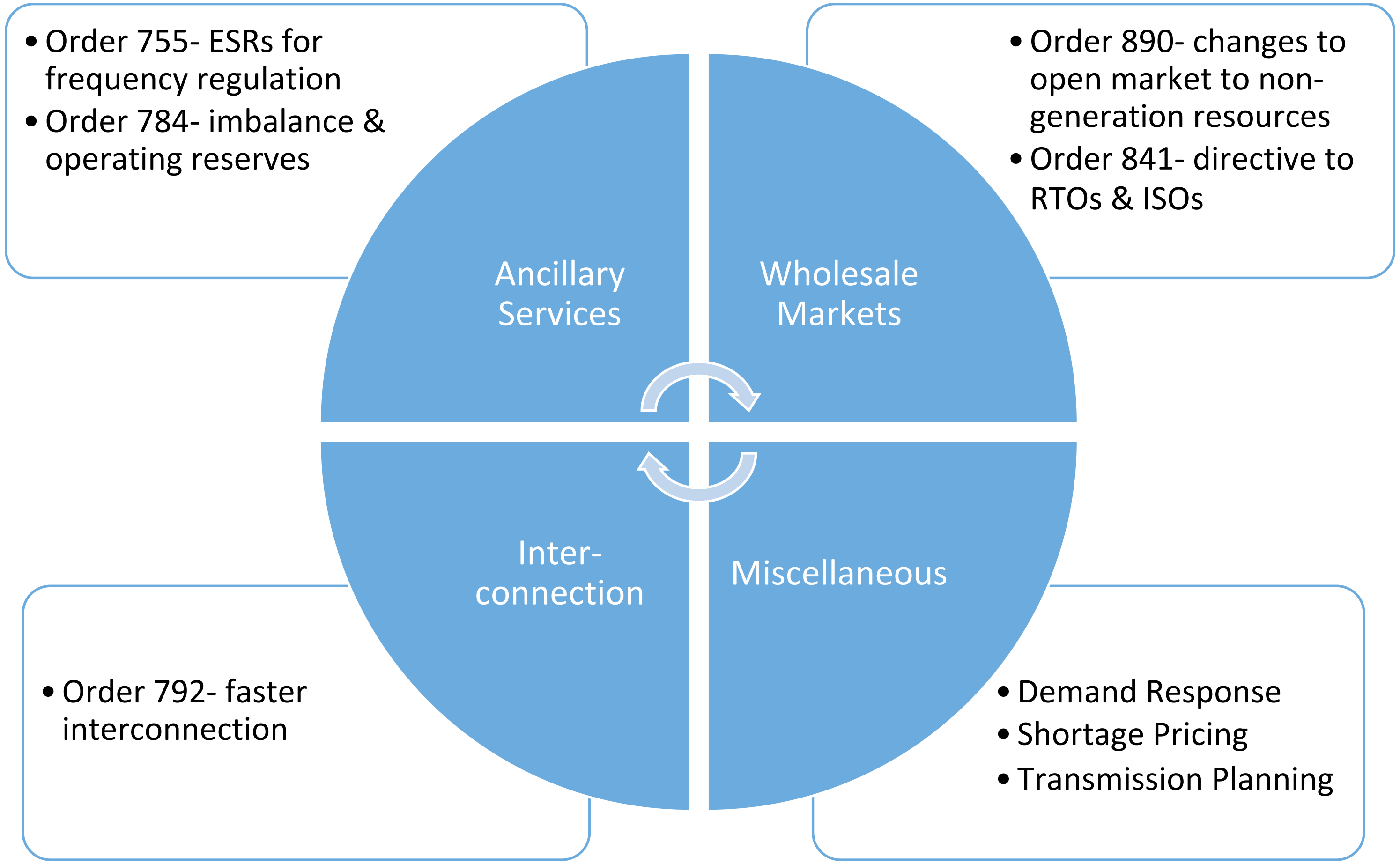
- Timeline – having this option well proved in next 2-3 yrs provides an option in the next investment cycle to meet incremental demand of ~70 GW from 2022-30

- Initial push and support is required to achieve economies of scale and low prices

- Finding areas where storage can solve todays problems with view of potentially much greater role in the future is needed – Time shifting, Ancillary Services, etc

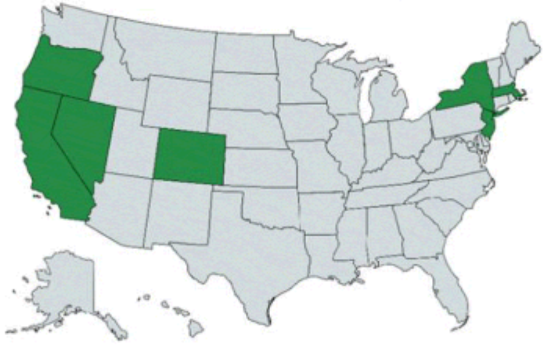
Regulatory Framework in the US

FERC has made several regulations enabling participation of energy storage resources (ESR) in markets and utility procurement



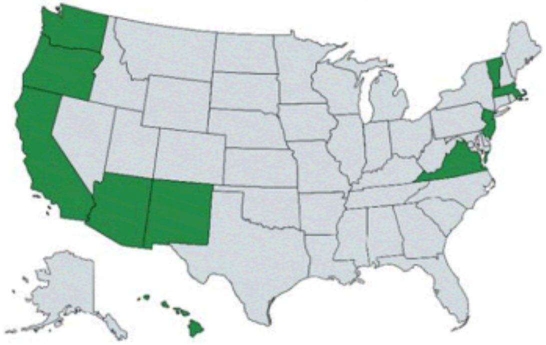
Even at the state level, battery storage is receiving significant regulatory attention

Procurement Targets



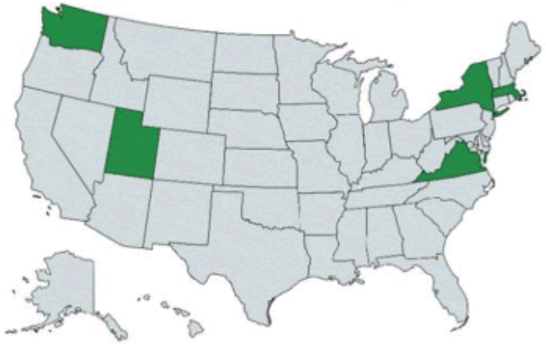
Seven states: CA, CO, MD, NJ, NY, NV, OR

Regulatory Adaptation



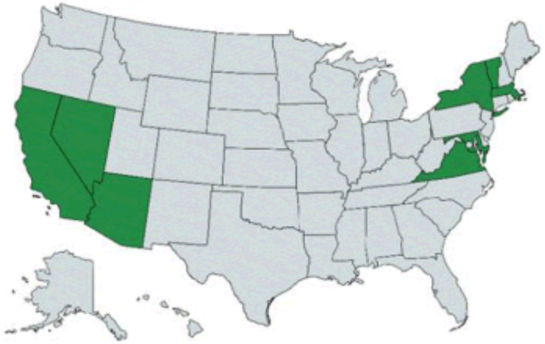
Ten States: AZ, CA, HI, MA, NJ, NM, OR, VT, VA, WA

Demonstration Projects



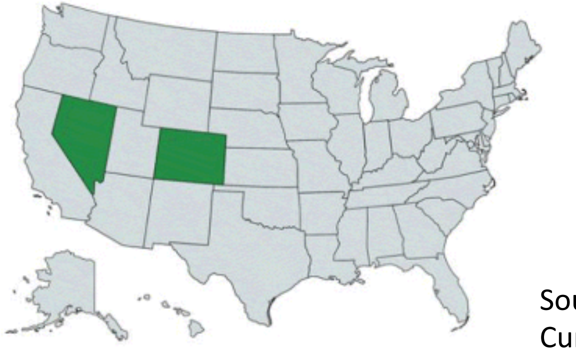
Five states: MD, NY, UT, VA, WA

Financial Incentives



Eight states: AZ, CA, MD, MA, NY, NV, VT, VA

Consumer Protections



Two states: CO, NV

- Storage procurement targets are mainly driven due to the increasing RE penetration
- Regulatory adaptation means that regulators recognize the benefits such as peak shaving, flexibility etc.

Source: Twitchell, J. (2019) “A Review of State-Level Policies on Electrical Energy Storage”, Current Sustainable/Renewable Energy Reports, June 2019, Volume 6, Issue 2, pp 35–41.

Key considerations for regulatory framework in India ..1

- Adequacy requirement mandate
  - Time of day/Seasonal demand assessment and corresponding least cost dependable power procurement plan
- Valuing storage and providing guidelines for procurement
  - Develop cost-effectiveness criteria so that all value chains provided by storage / other flexible capacity are counted for e.g. capacity value
- Develop rules for market participation
  - Allow market participants to change direction instantaneously in the day-ahead/real-time market

Key considerations for regulatory framework in India ..2

- Technology neutral deployment mandate
  - E.g. CA requires utilities to procure ~5 GWh of storage capacity by 2020

- Reserves requirement assessment – Exploring alternatives (including storage as an option) for replacement of high cost 'Reliability must run' resources (refer to CA experience) – Need for cost benefit analysis.

- Rewarding fast response through ancillary services market – enabling all resources including storage to compete for this segment. (Can/Should the system operators be asked to procure part of such services requirement?)

- Fiscal incentives

Thank you

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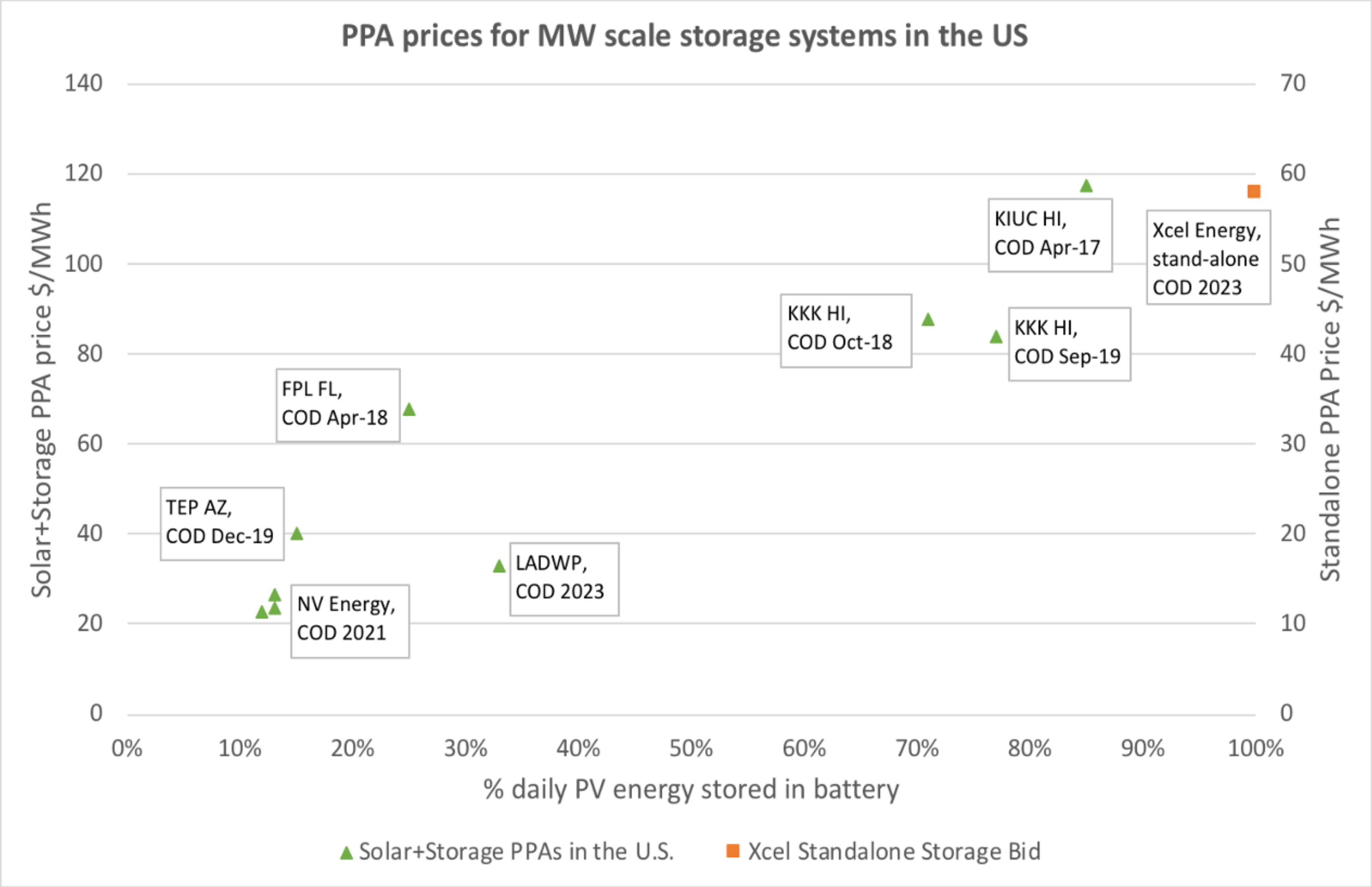
Dr. Sushanta Chatterjee (sushanta_chat@yahoo.com)

Additional Material

On average, storage adder in the US is ~0.6 cents/kWh for every 15% of PV energy stored in batteries



Source: Deorah, Abhyankar et al (2019)

Battery Storage Cost Estimation

Battery Storage Cost Estimation Methodology

- We use a combination of two methods to estimate the battery storage costs in India:
    1. **Market Based**: Conversion of most recent US bids and PPA prices using appropriate interest rate / financing assumptions
    2. **Bottom-up**: Using global battery pack prices, US benchmark BOS costs scaled to India using CERC approved BOS costs for solar projects

- Both methods lead us to a very similar prices

Details on converting the US bid / PPA prices to India (Methodology #1)

Off-taker in US (COD)	Category	% of PV MWh stored in battery	PPA price ($/MWh)	Unsubsidized ($/MWh)	India estimate ($/MWh)	India estimate (Rs./kWh)
NV Energy (Jun 2021)	Co-located with solar	12%	22.8	32.57	41.51	2.91
NV Energy (Dec 2021)	Co-located with solar	13%	23.5	33.57	42.79	2.99
NV Energy (Dec 2021)	Co-located with solar	13%	26.4	37.71	48.06	3.36
TEP AZ (Dec 2019)	Co-located with solar	15%	40	57.14	72.83	5.10
LADWP (2023)	Co-located with solar	33%	32.97	47.10	60.03	4.20
Xcel Energy - standalone (2023)	Standalone storage	N/A	57.95	82.78	105.50	7.39

Detailed assumptions for estimating the bottom up storage costs in India (Methodology #2)

Component	U.S. 1 MW/ 1 MWh System (standalone) ($/kWh)	Scaling Ratio (U.S. to India)	India 1 MW/ 1 MWh System (standalone) ($/kWh)	Scaling Ratio (1-hour to 4-hour system)	India 1 MW/ 4 MWh System (standalone) ($/kWh)	India 1 MW/ 4 MWh System (with PV) ($/kWh)
Battery pack (global)	176	0%	176	0%	176	176
BoS	100	-49%	51	-51%	25	15
Inverter	70	0%	70	-74%	18	11
EPC	88	-78%	20	-60%	8	8
Soft cost (excluding taxes, land, permitting and interconnection fees)	61	-60%	25	-36%	16	16
Total	495		341		242	225

Other Key Assumptions in Battery Cost Estimation

Variable	Value
Exchange rate	70 Rs./$
Total charging/discharging cycles available	3,650 cycles
Full charging/discharging cycles per year	365 cycles
Project lifetime (N)	20 years
Battery Life	10 years (implies 1 battery replacement needed in project life)
Depth of discharge (DOD)	90%
Rated capacity (C_{rated})	1 kWh
Annual degradation rate of capacity (DEG)	1.0% per year
Interest rate (r)	11%
O&M cost, assumed to be constant (O&M)	1% of CapEx
Residual project value after lifetime ($V_{residual}$)	10% of CapEx

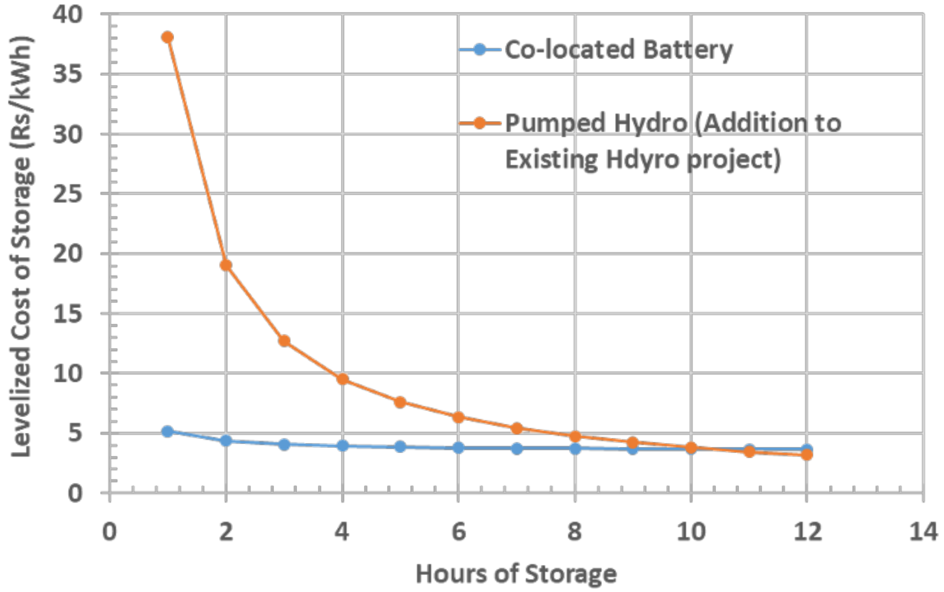
Comparative Economics of 4 hours of Pumped Hydro and Battery Storage Systems (FY 2025 delivery)

	Pumped Hydro		Battery Storage		
	Addition to existing hydro stations	**New build**	**Co-located with solar on existing sites**	**Co-located with solar on new sites**	**Stand-alone**
Storage Capacity	1 MW / 4 MWh	1 MW / 4 MWh	1 MW / 4 MWh	1 MW / 4 MWh	1 MW / 4 MWh
Capital Cost	Rs 8 Cr/MW	Rs 12 Cr/MW	$100/kWh	$122/kWh	$134/kWh
Life (years)	30	30	10-15 (replacement of battery pack considered)	10-15 (replacement of battery pack considered)	10-15 (replacement of battery pack considered)
Days of operation per year	300	300	300	300	300
Construction time	3-4 years	8-10 years	~3 months	~6 months	~6 months
Land requirement	~2-5 Acres/MW (Assuming ~300 m net head)		~0.1 Acres/MW		

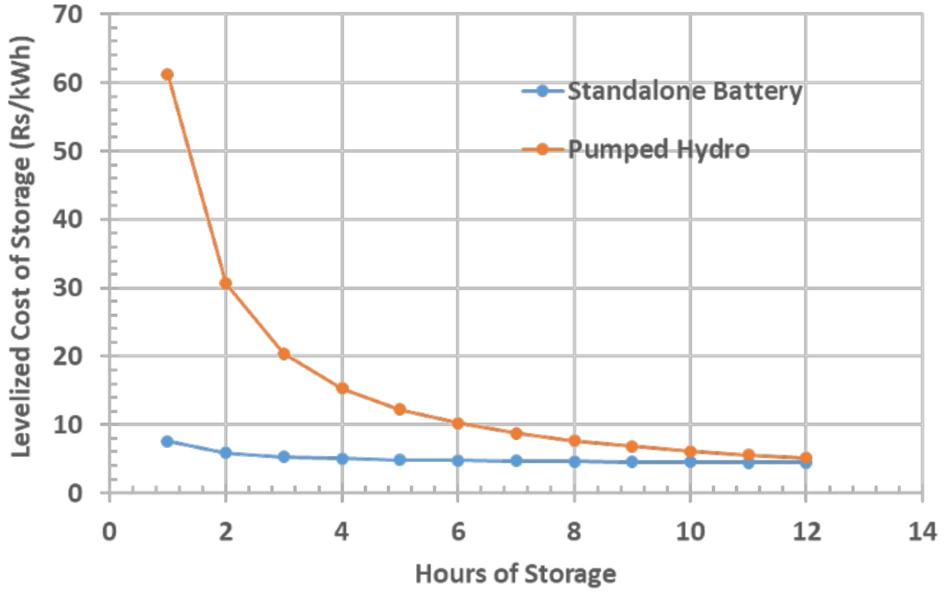
- Pumped hydro is very site specific, requires long lead times with potential time/cost overruns
- Battery storage offers significant option value and opportunity for course correction e.g. what if the demand increases suddenly or does not grow as planned etc.

Pumped hydro is MW-constrained, while battery storage is MWh-constrained

This means that for low storage hours (up to 6-8 hours or so), batteries are more cost-effective.
As hours of storage increase, pumped hydro becomes more cost-effective, as shown in the following charts.



Co-located battery storage systems are cost-effective up to 10 hours of storage, when compared with adding pumped hydro to existing hydro projects.

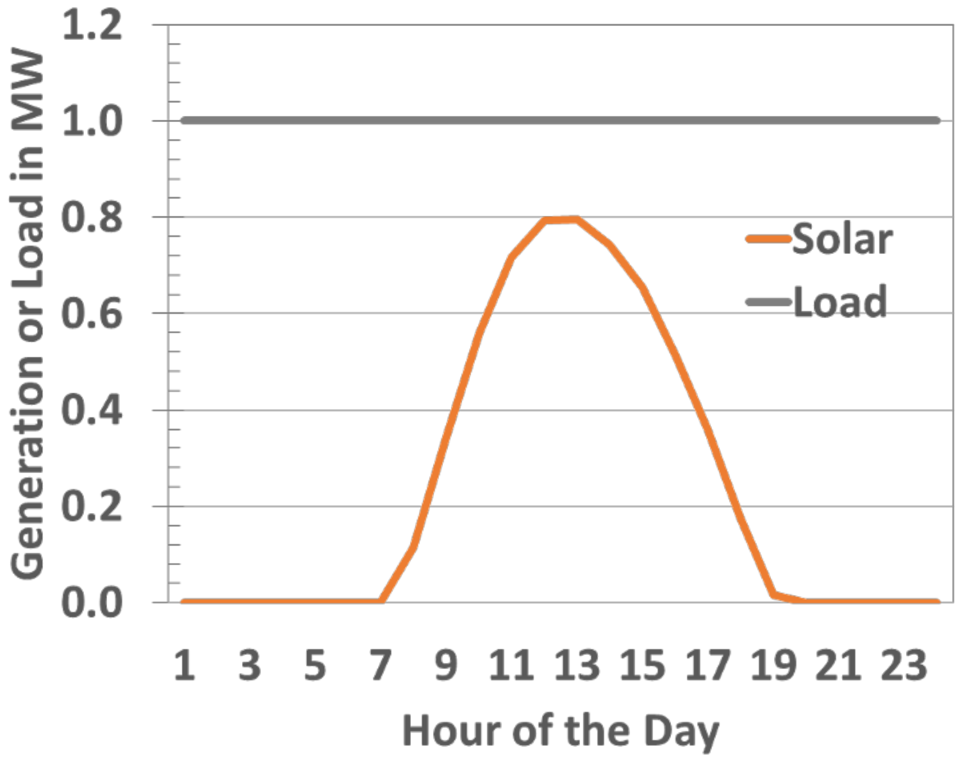


For new builds, using pumped hydro cost of Rs 12 Cr/ MW per CEA, battery storage is always cost-effective irrespective of the hours of storage.

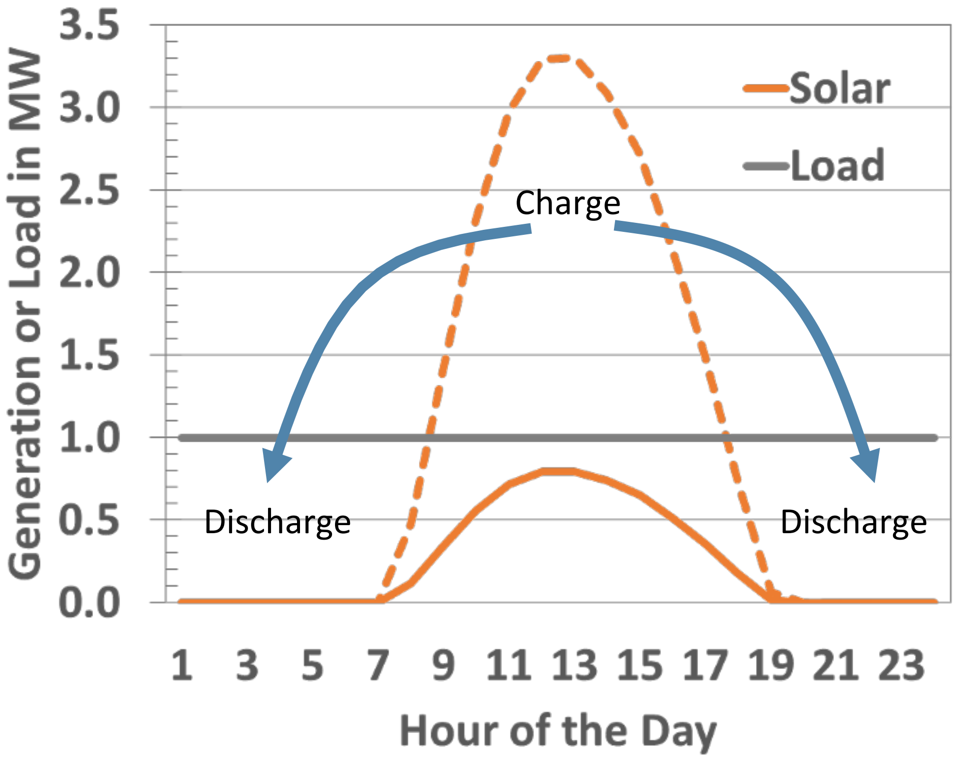
In general, by 2030, 4-hour storage system is found to be sufficient in India (shown subsequently)

How much storage is required for flat-block solar?

Consider an example system of 1 MW flat load. Total energy required during a day = 24 MWh



1 MW solar power plant would only supply ~22% of the total energy requirement

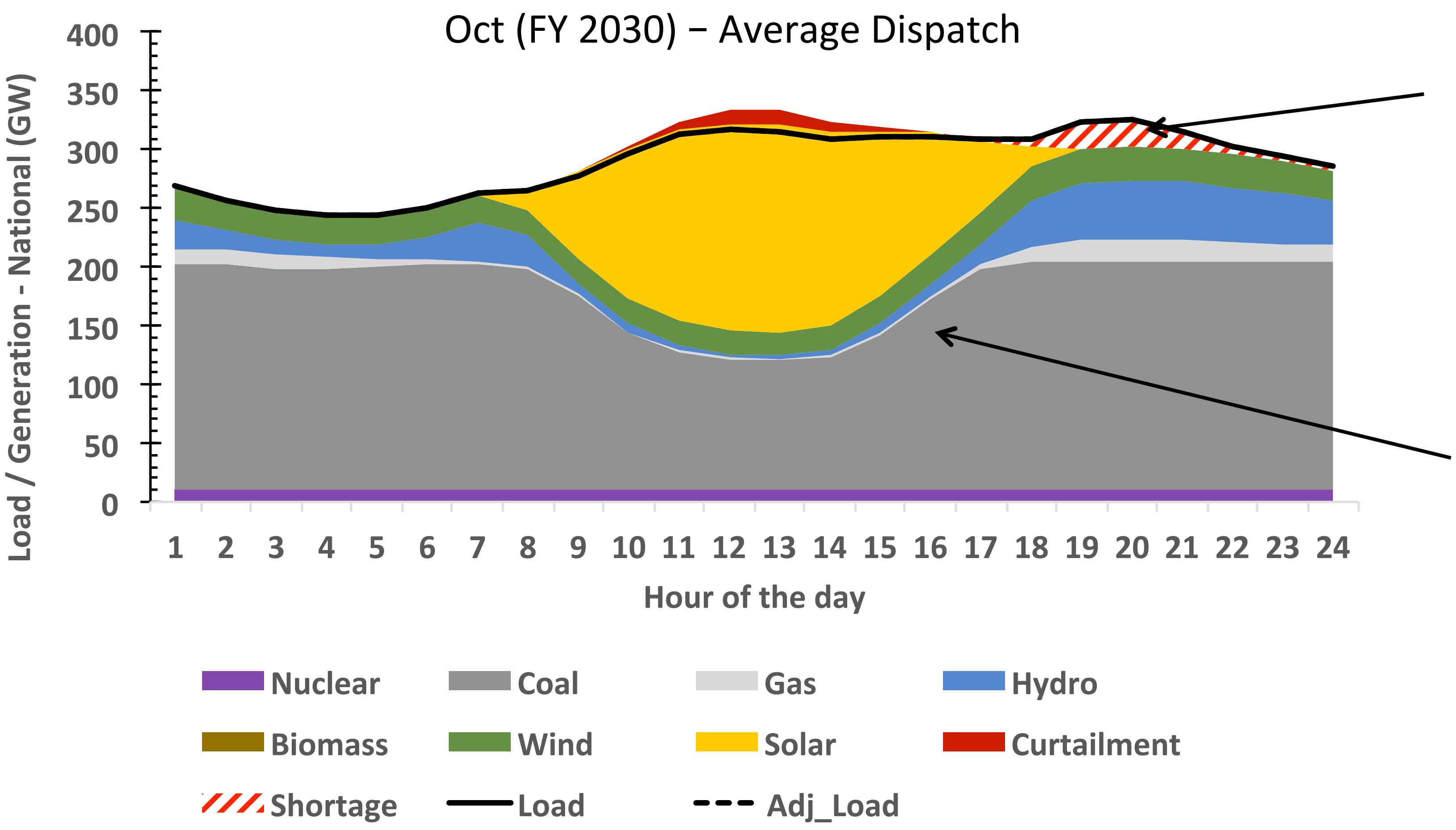


For flat-block power, 4 MW of solar capacity with ~13 MWh of storage (~60% of PV output) is needed

- Tariff adder for storing 60% of PV output in batteries would be ~Rs 2.3/kWh by 2025 and ~Rs 1.8/kWh by 2030

➔ **Flat block power cost would be ~Rs 4/kWh by 2025-2030, nominally flat for 25 years !**

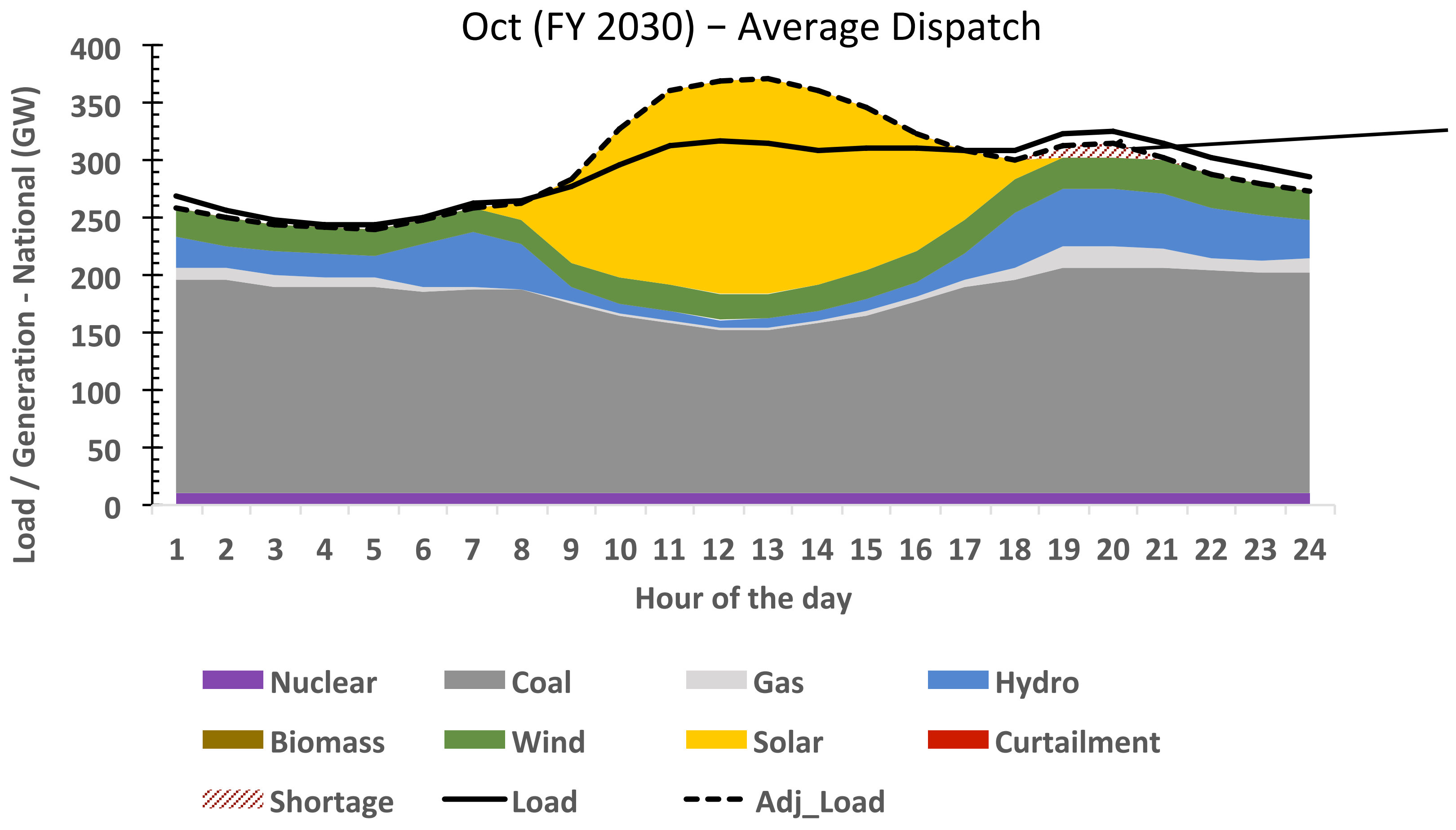
If no new thermal capacity is built beyond 2022, peaking shortages may develop in absence of agricultural load shifting and energy storage



A consistent evening peak shortage of ~20-30 GW is observed despite using gas capacity to its fullest (except for monsoon months).

In addition, significant ramping challenges for thermal plants.

Even with Agricultural load shifting, ~10-15GW of sustained peaking shortages may develop (except monsoon)



A consistent evening peak shortage of ~10-15 GW is observed despite using gas capacity to its fullest (except for monsoon months).

Coal ramping challenges could be largely avoided

Additional Details on Regulatory Framework in the US

FERC Order 841 (2018)

- Ensure that a storage resource can provide all the services it is technically capable of providing,
- Ensure that an energy storage resource can be dispatched and can set market clearing prices as both a buyer and a seller,
- Account for the physical and operational characteristics of storage resources through bidding parameters or other means,
- Establish a minimum size for participation in RTO/ISO markets that does not exceed 100 kW, and
- Specify that the sale of electricity from the RTO/ISO markets to a storage resource that the resource resells must be at the wholesale locational marginal price.

Reforms in wholesale markets, procurement of ancillary services & interconnection procedures (FERC)

Order 890

- Changes to open access transmission tariff to open energy/ancillary markets to non-generation resources
- For resources that could provide regulation, frequency response, reactive supply, etc.

Order 841

- ESRs allowed to participate in all capacity, energy & ancillary markets
- ESR can set price as wholesale buyer and/or seller
- ESR to pay wholesale LMP for energy bought from market

Orders 755 & 784

- 755- Freq Reg rules changed to properly reward fast ramping capabilities of resources such as ESRs
- 784- more revenue opportunities for ESRs, eg imbalance & operating reserves

Interconnection Procedures & Order 792

- For fast-tracking of interconnection requests made by ESRs
- Reforms on improving predictability, transparency & speed of interconn. process

Miscellaneous Orders & Reforms (FERC)

Demand Response

- Behind-the-meter storage can act as effective DR resource
- Order 745 in 2011- DR resources in markets to be paid same as generation resources

Transmission Planning & Shortage

- Order 1000- consider non transmission alternatives for planning (eg ESR, DR, dist gen)
- Shortage pricing encourages entry of new supply resources

Cost Recovery of Electric Storage

- Electric storage resource can provide transmission/ grid support at cost-based rate (case-to-case basis)
- Can also participate and earn revenues in market