Prayas (Energy Group) Comments and suggestions on Draft National Electricity Policy[1]
13th May 2021

The major issues covered in the submission are noted below:

[1] Comments and suggestions based on draft National Electricity Policy published by Ministry of Power on 27th April 2021 vide Letter No.23/23/2018-R&R.

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Ministry of Power constituted an Expert Committee to prepare and recommend NEP 2021, and vide letter dated 27th April 2021, has solicited suggestions and comments on draft National Electricity Policy. Prayas (Energy Group)'s comments and suggestions on NEP 2021, focus on multiple aspects including the need to:

— facilitate retail competition and consumer choice;
— accelerate supply-mix transition away from coal towards renewables;
— enhance financial viability of sector, especially distribution companies;
— focus on providing quality, reliable, affordable supply and service;
— strengthen regulatory governance and;
— ensure socially and environmentally responsible generation

The comments also have specific in-line suggested modifications to the draft. Please note that the text from the draft is marked in *italics*, deletions are highlighted using with strikethrough ~~strikethrough~~ and suggested additions are <u>underlined</u> for easy identification.

1 Harmonisation of the Electricity Act, Tariff Policy and National Electricity Policy

The Indian electricity sector is witnessing a major transition, driven by technology, resource and climate considerations. Renewables are replacing conventional generation. Markets, metering and digitization are transforming distribution, and electricity's share as the preferred energy source is increasing in transport, industry and cooking. For a well-balanced response to this transition, the three key documents – Electricity Act (EAct), Tariff Policy and National Electricity Policy (NEP) - should provide harmonious legal framework and policy directions. The current NEP draft refers to proposals in earlier drafts of the E Act amendment, outlines many ongoing government initiatives and has provisions, which ideally should be dealt in the Tariff Policy. We strongly suggest that the Central Government take up public consultation and revision of these three documents at the same time. This will also help to make NEP crisp and focussed, providing broad, but clear policy directions and targets.

2 Objectives and effectively meeting the objectives

The National Electricity Policy (NEP) was first notified in February 2005. As per Section 3(3) of the EAct, Central government may revise or review NEP from time to time. While there have been amendments in Tariff Policy (TP), the only reviews of NEP so far have been by the FOR in 2009[2] and by the Lok Sabha Standing Committee on Energy - Review report in 2017 and Action taken report in 2018.[3] These reviews focus on the progress in specific actions or targets proposed in NEP – like rural electrification, capacity

[2] http://www.forumofregulators.gov.in/Data/policy_Imp/NEP_Report_2007-08_final%2017.12.pdf
[3] https://eparlib.nic.in/bitstream/123456789/65236/1/16_Energy_30.pdf and https://eparlib.nic.in/bitstream/123456789/762149/1/16_Energy_34.pdf

addition, setting up of grievance forum etc. There were no attempts to suggest amendments or revision of the policy. This step to revise the NEP after 16 years is indeed late, but better than never. Considering the many developments in technology and institutional structure in the electricity sector, periodic review and revision of NEP are essential.

It is suggested that **Para 1.2 be modified to reflect this**:

Notwithstanding anything done or any activity undertaken or purported to have been done under the provisions of the National Electricity Policy notified in the year 2005, the same shall in so far as it is not inconsistent with that Policy, be deemed to have been done or undertaken under provisions of the revised National Electricity Policy 2021.The Central Government will conduct periodic review and revision of NEP preferably once in five years.

The Introduction as well as the Aims & Objectives of the 2005 policy had clear articulation on the catalytic role of electricity in socio-economic development of the country through rural electrification and provision of reliable competitive electricity to industrial and service sectors[4].Targets were provided for many parameters including capacity addition, rural electrification, loss reduction and protecting consumer interest. Sections 1.4 and 1.5 of the 2021 NEP draft do articulate some issues faced by the sector, including enhancing 24 x 7 access to rural and poor, high financial losses of DISCOMs, high AT&C loss in pockets and integration challenges of high RE capacity. Further, the role of the regulatory commission in protecting consumer interest, ensuring accountability of utilities, fostering new technologies and adoption of new business models will be critical in the midst of the transition. To facilitate this, regulators will have to play multiple roles including formulating facilitative frameworks, ensuring compliance and scrutinizing performance. But the Aims & Objectives as well as subsequent sections do not sufficiently present policy directions to address these issues.

The following changes are suggested to the Aims and Objectives in **Para 2**:

v) Ensure 24x7 ~~S~~supply of reliable and quality power of specified standards in an efficient manner, especially to rural areas and to small consumers by 2023

(vi) Move ~~towards light touch regulation~~ away from cost plus regulation towards better performance accountability

viii) Ensure affordable electricity to rural and small consumers

3 Thermal Generation

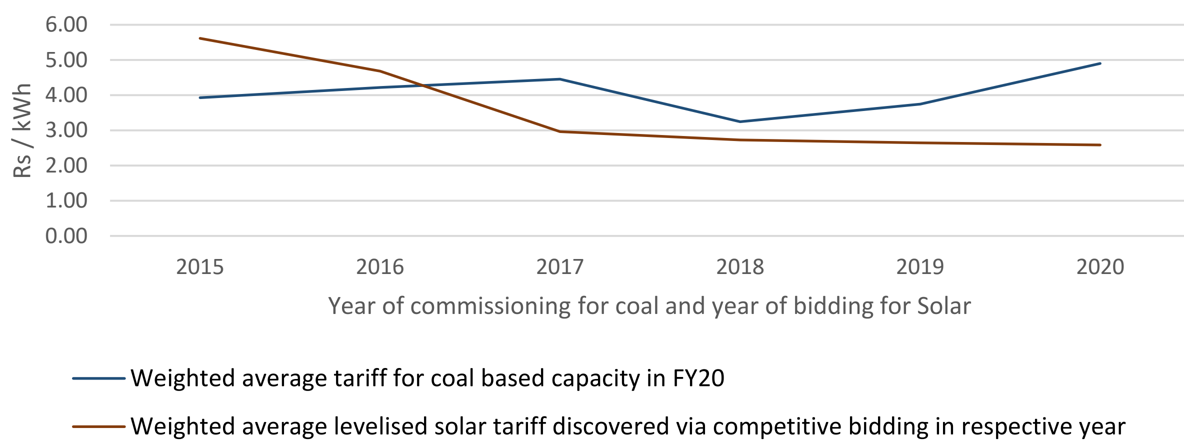
Section 5.6 notes that coal based generation capacity may still be required to be added in the country, as it continues to be the cheapest source of generation. While this may have been true in the past, the

[4] To quote from Section 1.2 of the 2005 policy: "Electricity is an essential requirement for all facets of our life. It has been recognized as a basic human need. It is a critical infrastructure on which the socio-economic development of the country depends."

situation has changed rapidly in the past few years. The average cost of electricity generation from coal-based capacity commissioned after 2015 has been around ₹ 4/ kWh and is increasing.

In contrast, as shown in Figure 1, the prices of renewables – particularly solar and wind – have been continually falling and are expected to continue to fall. Although the discovered prices for solar are not directly comparable with the cost of coal-based generation, the price trend are nonetheless instructive. A recent tender issued by NTPC Ltd[5], seeking bids from solar developers to displace generation from its more expensive plants in order to save costs indicates that solar can displace coal-based generation from some plants during day time even now. Production cost simulation and other advanced modelling studies at the state (Prayas study for Maharashtra[6]) and country level (TERI study for India[7]) have suggested that it will be economical to meet electricity demand without increasing coal thermal capacity beyond what is in the advanced stage of construction.

Figure 1: Tariffs for recently commissioned coal power plants as on 9th August 2020 compared to average levelised solar tariffs discovered in the year of commissioning



Source: Prayas analysis based on MERIT database, CEA documents, regulatory orders, Lok Sabha Q&A, MNRE Demand for Grants, SECI results and various newspaper articles

In the light of these trends, the NEP should:

3.1 Strongly discourage new coal-based generation capacity

India has over 60 GW of coal-based generation capacity in the pipeline, of which about 35 GW are under construction and over 25 GW at various stages of obtaining permissions. The capacity in the pipeline, in addition to the existing capacity, should be sufficient to meet India's coal-based electricity capacity requirement of 2030, which is likely to be around 240-250 GW, even if about 25-30 GW of old coal capacity retires. Moreover, given prevailing trends of coal-based electricity, renewables and storage, coal-based capacity for electricity generation is likely to peak by about 2030. Considering the addition of

[5]https://www.ntpctender.com/NITDetails/NITs/23172
[6] https://www.prayaspune.org/peg/images/Webinars/Gridpath/Prayas-MH-model-GridPath-23Nov2020.pdf
[7] https://www.teriin.org/sites/default/files/2020-07/Renewable-Power-Pathways-Report.pdf

any new coal-based capacity beyond the existing pipeline is highly risky[8], as it stands a high chance of turning into a stranded asset and locking into a high cost and high carbon path. Hence, any coal-based capacity addition beyond the current pipeline should be strongly discouraged and if approved should be added only through competitive bidding.

The following **Para 5.10** should be added:

In order to prevent further build-up of stressed assets, and to avoid lock-in of environmentally and economically costly capacity, new coal thermal capacity should be avoided and any new coal based generation project should be considered for environmental or electricity regulatory process approval only after recommendation of the CEA. While considering any new coal thermal project for such recommendation, CEA shall take into account overall demand - supply situation in the country, stranded and underutilised thermal capacity, and possible economically better alternatives to provide similar benefits over the lifetime of the proposed capacity. Any capacity addition requirement, identified through this process should be added only through competitive bidding.

3.2 Compliance with Environmental Norms

While the NEP has reemphasized the need for time-bound compliance with the emission norms notified by MoEF&CC and also specified the process for regulatory approval to streamline the process, it is also critical that generators are held accountable for cost-optimal capital investments and use of equipment to meet norms. Thus, it is important that there is benchmarking of capital costs for pollution control equipment installation. Further, regulatory approval for all additional costs (fixed and variable) incurred due to compliance with the norms should be provided only after certification from the pollution control board validating compliance.

Thus, Para 14.5 can be modified as suggested:

"…Efforts must be made to meet the compliance norms in the most cost effective way in order to minimize cost to consumers. These impacts should be captured by Regulators in the tariff determined under Section 62 of the Electricity Act. In case of tariff determined through tariff based competitive bidding under Section 63 of the Electricity Act 2003, these impacts should be allowed under "Change of Law" provision. To ensure cost-optimal investments, Commissions should develop a cost benchmarking framework for equipment cost or other solutions adopted to ensure adherence to the emission norms in a timely manner. The regulatory certainty provided by such a cost benchmarking exercise can spur the investment required to install such equipment. All associated cost for meeting norms should be

[8] IEA analysis shows that global spending on coal-fired power plants dropped by 6% in 2019, the lowest in a decade and that final investment decisions for coal-fired generation dropped for the fourth year in a row to below 17 GW – the lowest level since 1980. This is indicative of increased risk perception with respect to coal-fired power plants: https://www.iea.org/reports/coal-fired-power. The recent announcement of Asia Development Bank in its draft policy to no longer finance any coal-related projects is also reflective of this shift.

approved for projects under Section 62 and Section 63 only if the generator is able to provide evidence validating that the norms were complied with for at least 95% of the period that the plant was operational through, for example, certification from the appropriate pollution control board. *Additionally, the use of biomass pellets (agro residue based) in co-firing with coal for power generation should be encouraged in order to curtail environmental pollution due to burning of crop residues."*

3.3 Development of policy for reclamation, restoration and rehabilitation post-retirement

With the ongoing transition and technology driven shift, it is likely that some projects, especially coal-based generation projects would be retired (based on project-specific cost benefit analysis) over the next decade. Given this eventuality, it is important that the policies and frameworks are in place to ensure project developers take responsibility for restoration and reclamation of the land, water bodies, air quality and ensure management of waste and infrastructure associated with project operations. Currently, such a policy guideline is present in the coal mining sector.[9] A similar framework should be introduced for power projects.

Suggested Para 14.7 can be added:

Appropriate policy guidelines shall be developed by the Central Government for reclamation, restoration and rehabilitation of the power project area after project retirement. The policy, aiming to restore the area by addressing impacts on land, water and air should also have provisions to address responsible waste disposal and infrastructure management. The policy should detail the responsibility of the project developers in planning, execution and financing restoration.

4 Hydropower

While there are many options for meeting peak demand in an efficient manner (Para 5.2), new hydropower plants are certainly not one of them. Similarly, while existing hydropower can aid in reliable grid integration (not just of renewables but of demand variation as well), adding new hydro power capacity is not a particularly effective solution for following reasons:

— **Cost over-runs and long gestation:** Large hydropower is a well-established conventional generation technology, being in existence for over a century. While the social and environmental impacts of hydropower are already well known, it is increasingly not an economic resource as it is made out to be. In response to a Rajya Sabha question on stalled hydro projects, the Ministry of Power stated that: *'As on 01.07.2017, there are 14 under construction Hydro Power Projects (above 25 MW), totaling 5,055 MW, which are stalled due to various reasons. The cost overrun calculated by CEA[10] due to these stalled projects is Rs. 25,593.78 cr.'* **Thus, there is on average, a Rs 5 Crore/MW cost**

[9] https://www.cmpdi.co.in/docfiles/mineclosure_guideline.pdf
[10] https://powermin.nic.in/sites/default/files/uploads/RS24072017_Eng.pdf

overrun for these projects, which is in stark comparison to the total cost of new solar projects (Rs. 3.5-4 Crore/MW) and new wind projects (Rs. 6-7 Crore/MW).

— **Long gestation periods**: The gestation period for hydro projects is significantly long, coupled with uncertainty due to various factors as already noted in the draft. The CEA quarterly review dated December 2019[11] notes the time delay for on-going projects. **The average time overrun for the 35 listed projects is a staggering 7.7 years (Prayas analysis).**

— **Viable Alternatives for flexibility**: A suite of emerging technologies can now provide a variety of the flexibility characteristics, which made hydropower a valuable resource for balancing in the past. Further, these are increasingly becoming available at much lower prices and with significantly lower gestation periods.

Thus, the entire value proposition for hydropower needs to be looked at afresh and new capacity addition should be strongly discouraged.

To this effect, we suggest the addition of **Para 5.16:**

Given the time and cost-overruns and long gestation periods associated with hydropower, capacity addition, especially for peaking should only be considered if alternate technology options are unable to provide requirement for flexibility and balancing at lower costs.

5 Renewables

5.1 Merging Solar and Non-Solar RPOs and removing requirement for HPOs.

Para 5.23 notes the long term RPO trajectory for states. This is a welcome and important guiding trajectory which states should pro-actively strive to achieve given the benefits of new renewables to lowering the cost of supply. A separate solar RPO was mandated at a time when solar prices were so high that no entity would have purchased it without a mandatory separate obligation. Now the situation is quite the reverse with solar being the cheapest generation source. Ideally, DISCOMs should have the full freedom to procure a mix of RE which is best suited for their load profile. As per the MoM of the Hon'ble MOSP (IC) for Power and MNRE regarding proposed amendments in the EA, 2003 dated 19th March, 2021, several states have made the demand for merging the solar and non-solar RPO and making them fungible. Thus, NEP should allow states the freedom of merging the solar and non-solar RPO targets into a composite single RPO. This will also allow innovative, new supply mix and bidding options such as wind-solar hybrid, solar plus battery storage, and RTC power.

Considering all the technical, social, environmental and economic drawbacks of large hydropower mentioned in this submission and detailed in the NEP itself, large hydropower should not be considered as a renewable energy resource for the purpose of the RPO. There should be no separate hydropower purchase obligation and it not be made part of the non-solar RPO. Large hydropower may be counted

[11] http://www.cea.nic.in/reports/others/hydro/hpm/QUARTERLY%20REVIEW%20NO.%2099.pdf

towards renewable energy in appropriate international comparisons since this is the practice in most countries.

Thus, Para 5.23 can be modified as follows:

Para 5.23: *Long term growth trajectory of RPOs' for non-solar as well as solar sources has been issued by the Ministry of Power uniformly for all States/UTs up to year 2021-22. Trajectory beyond this period, if required, shall be notified as a single composite RPO by the Ministry of Power in consultation with MNRE from time to time. Solar costs have become competitive in recent years. As such, there is no need for separate RPO for solar and non-solar. DISCOMs shall be free to meet their overall RPO requirement from any approved renewable energy source, that best meets DISCOMs' requirements.* ~~*Large hydropower projects (with capacity more than 25 MW) shall also be treated as renewable source of energy. The Ministry of Power shall also notify a trajectory for Hydropower Purchase Obligation for a period upto 2029-30 and may extend it further, if required.*~~

Similar provisions should also be part of the National Tariff policy.

5.2 New mandate for a storage purchase obligation

The GoI has already cleared the National Mission on Transformative Mobility and Battery Storage. The dramatic fall in battery price is expected to bring in a paradigm shift in the power sector, esp. with regard to renewable grid integration. Electric storage is a very modular system and allows for use in multiple applications. A CEA report on Optimal Generation Capacity Mix for 2029-30[12] projects a national Battery Energy Storage capacity of 27,000 MW/108,000 MWh (daily) by 2029-30. Hence, it is critical to initiate large scale procurement of grid-scale battery storage systems and gain valuable experience and reap its multiple reliability and economic benefits. States should be encouraged to set targets for stand-alone storage systems and solar + storage systems based on the system needs. A potential Storage Purchase Obligation (SPO) which can comprise of various existing and emerging cost-effective solutions that provide appropriate flexibility should be encouraged. DISCOMs should be free to choose specific forms of procurement - hybrid RE + storage or RE and storage independently. A Storage Purchase Obligation of say 2% by 2025 increasing to 4% by 2030 could be initiated. To kick-start the RE+Storage procurement process, GoI could consider providing Viability Gap Funding for renewable energy (wind/solar) projects which are coupled with battery systems and procured through a process of competitive bidding.

To this end, a new Para 5.27 can be added:

Various studies, including CEAs Optimal Generation Capacity Mix study have identified significant requirement of grid scale storage systems. To meet this requirement and to kick-start development of storage at large scale, Storage Purchase Obligation (SPO) should be specified by MoP and adopted by SERCs. To start with, SPO could be 2 % of the DISCOMs peak load by 2025 and 4% of peak load by 2030.

[12] https://cea.nic.in/old/reports/others/planning/irp/Optimal_mix_report_2029-30_FINAL.pdf

DISCOMs and ERCs can adopt multiple options such as RE + storage, stand-alone storage, transmission linked storage to cost optimally deploy and utilise storage capacity.

Similar provisions should also be part of the National Tariff policy.

5.3 Moving away from RE concessions to valuing services at cost

As noted in Para 5.24, there is certainly merit in exploring market based options for RE with fair risk and reward sharing mechanism. As a principle, third party sale and captive route should be allowed to thrive on the basis of its own economic proposition, rather than being driven by concessions/waivers. This is especially the case as many of the recent concessions being provided (waiver in inter-state transmission charges, concessions on open access and wheeling charges etc.) are cross-subsidised by other users of the grid rather than being subsidised by the union/state government. Moving away from a concessions-based regime for new projects will aid the development of robust RE markets with appropriate market signals for discovery of prices and framework for risk assessment. Such signals are necessary for the RE sector to grow without undue fiscal and economic duress. It is also important to ensure that grid services necessary for RE development are provided by appropriate stakeholders such as distribution companies, LDCs and transmission utilities, as long as they are valued and priced appropriately. This is especially the case for banking services. Till specific market instruments for green power have adequate liquidity and offer flexibility, banking services by DISCOMs would be required. Instead of denying this service, it can be valued on a block-wise basis based on costs incurred by the DISCOMs. Similarly, the entire cost of deviation caused due to wind and solar generators should be borne by the generators rather than allowing a 10-15% error without penalties as is currently the case.

To give effect to this, Para 5.24 can be modified as follows:

Para 5.24: '*…Further, the rapid pace of RE development and falling RE tariffs indicate potential for market-based mechanisms. Market-based options need to be explored, which can help to strike a desired balance between capping investor's price risk while ensuring some exposure to basic market risks of forecasting, scheduling and balancing. Considering falling RE tariff and likely increase in RE capacity, it is necessary to move away from incentives and concessions based approach for RE development in the near future, say two to three years. Simultaneously, it is necessary to appropriately value and provide various grid services, such as banking, grid connectivity, transmission services required for effective deployment of RE capacity. This would be a balanced approach rather than providing concessions on one hand and denying grid services on the other.*'

Similar provisions should also be part of the National Tariff policy.

5.4 Virtual net metering for electricity use in public services and government buildings

Electricity bill payments from government and public service consumers, such as public water schemes, gram panchayat offices, street lights, Jilha Parishad Schools, police stations etc., is often delayed and has been contributing to reducing collection efficiency. These being public services, electricity supply cannot be disconnected. This can affect the working capital requirement and strain the finances of the DISCOM. To address this problem, virtual net metering can be allowed for such 'public consumers'. Under this scheme, States can mandate, say the SNA/Genco to install a large, say 100 MW solar plant as a captive plant for all ‘government / public service consumers’ in the state. States can directly pay for the power procurement from such a plant and respective electricity consumers could be given credit for such virtual net metering plant. Virtual metering can be restricted only to government offices, urban and local bodies, public schools and hospitals to address the issue of timely revenue recovery and ensure reliable supply for these services. The mechanism can help to provide power to these consumers at a fixed rate and also help meet the DISCOMs RPO requirement**.**

Suggested Para 5.28 can be added to the NEP:

The Central and State Governments, State Commissions and DISCOMs, should evolve ‘virtual, group net metering’ mechanism for supply to ‘public service’ consumers such as government offices, public water works, government schools, gram-panchayat connections, street lights etc. Such projects could be set up with government support, and will help address the issue of providing adequate and affordable power to public service consumers. Under this mechanism government entities will be responsible for directly paying to RE developers based on PPA tariff. This will help address issue of arrears from government consumers for DISCOM.

Similar provisions should also be part of the National Tariff policy.

5.5 Innovative tariff design to address curtailment

Para 5.21 notes the risks of curtailment and non-payment by DISCOMs. While a two part tariff is one possible solution to this issue, it is by no means the only one and SERCs/DISCOMs should be encouraged to try out innovative policy measures to address this apart from strictly enforcing the must-run status under IEGC. A single part tariff, but based on Availability instead of Actual Generation or a provision in the PPA for compensation in case of curtailment, could also address this concern. Similarly, differentiation in tariffs for hybrid projects for peak and off-peak periods is another example.

Hence Para 5.21 could be reworked as below:

Para 5.21: *Tariffs for renewable energy sources like wind and solar power which are dependent on nature for generation are presently energy only tariffs and are thus paid only when energy is drawn by the State Distribution Companies. ~~This gives a perverse incentive for them to not draw this power although it is in the 'must-run' category Tariff of such generators must cover the risk for any curtailment of power by the distribution licensee for reasons other than grid security or transmission constraints. Two-part tariff mechanism may be an option, particularly in case of medium/long-term procurement with hybrid operation of renewable energy source with conventional generation~~. MoP, FOR and SERCs may work appropriate tariff structure and provisions in the PPA for RE projects to cover the risk of any curtailment of the generation for reasons other than grid security and transmission constraints. There should also be a limit on curtailment due to these factors, beyond which compensation should be payable to RE generators.*

Similar provisions should also be part of the National Tariff policy.

5.6 Adopt modelling and planning tools to address variability and intermittency

Para 5.25 talks about a pragmatic mechanism for sharing the costs arising out of grid integration of renewables. While this point is well taken, it is important to differentiate between 'variability' referring to predictable changes (say within a day for solar and monsoon / non-monsoon for wind) and 'intermittency' referring to more short duration unexpected changes in generation (cloud cover or gusts of wind). While the latter needs to be dealt close to real time as part of the F&S regulations (narrow allowable error bands over time and pass on the entire cost of deviation back to the RE generators), the former (variability) is a much more complex issue which needs to be addressed as part of long term IRP. In terms of managing variability and having adequate 'balancing capacity' or reserves, DISCOMs need to be encouraged to undertake more rigorous capacity expansion and production cost simulation exercises which can objectively assess the costs and value of various options (incl. demand side) to meet the generation-demand balance.

Para 5.25 should be replaced as follows:

<u>*DISCOMs and ERC need to adopt advanced modelling tools and planning approaches to meet variability of RE generation and intermittency in an economically optimal manner considering various technological options (e.g., storage) as well policy and tariff measures such as seasonal tariff, peaking tariff, capacity markets, deepening and widening national level power market and flows etc.*</u>

5.7 Distributed grid connected renewables

Para 5.26 outlines the importance of supporting distributed RE like rooftop solar. States should have the right and prerogative to decide state-specific regulatory and accounting mechanisms for rooftop solar and the new draft amendment to the Consumer Rules, 2021 which abides by this jurisdictional freedom. States, SERCs and DISCOMs also need to revise their rooftop solar regulations.

Para 5.26 maybe modified as follows:

'...One way of promoting solar PV systems, particularly in household applications and small industries is through net metering. ~~The Electricity (Rights of Consumers) Rules, 2020 provide such metering for loads up to 10 kW.~~ <u>Where possible, along with virtual net metering options,</u> State Governments <u>can</u> ~~should~~ consider installing solar PV system in office & school buildings, panchayats and other public service institutions. <u>DISCOMs and ERCs should operationalise a more balanced risk and reward sharing framework for rooftop solar which allows and retains consumer choice over accounting frameworks (net/gross metering; net-billing, behind the meter systems etc.) but also values DISCOM services (such as energy banking, reliability etc.) appropriately.'</u>

Similar provisions should also be part of the National Tariff policy.

5.8 Framework for environmental clearance for large renewable energy projects

Investment in low cost renewable energy will achieve two of the stated objectives in the draft NEP, namely i) promotion of clean and sustainable generation of electricity and iii) revitalisation of DISCOMs. However, RE projects, especially large RE projects are resource intensive and in the absence of appropriate governance frameworks, development of RE could result in non-optimal resource allocation and adverse socio-environmental impacts, leading to sub optimal development of RE sector. To address this, the NEP should stipulate the requirement for socio-environmental impact assessment and environmental clearance process for large RE projects.

It is suggested that **Para 14.8 be added to the NEP:**

Large RE projects should be initiated after appropriate environmental clearance. To facilitate this, technology specific frameworks for impact assessment and clearance should be developed in consultation with communities and relevant stakeholders within a year of notification of the policy.

6 Transmission and grid operation

Planning and approval of projects are dealt with in Paras 6.1 to 6.6. CEA is to prepare short term (5 years) and perspective (10 years) plans, while CTU/STUs are to prepare implementation plans (5 years). Approval of ISTS projects is to be done by National Committee on Transmission and InSTS by similar State arrangements. CTU has been carved out of POWERGRID only recently and all STUs are still part of the state transmission companies. For optimisation of resources and ensuring reliability, it is better to have a single national agency to undertake ISTS and InSTS transmission system planning, including implementation plan.

Separate National Agency for transmission planning: Paras 6.1 to 6.7 have suggested that CEA be responsible for transmission planning. **Given the requirement for coordinated, agile planning, a separate national authority, which coordinates with Ministry of Power, Ministry of New and Renewable Energy, CTU, STUs and other transmission grid stake holders can be considered.** In addition to preparing the plan, the agency should conduct mid-term reviews, prepare implementation plans and provide inputs to national and state committees for approval. To facilitate this, a national transmission data base, with planning and operational data should be prepared and maintained by this national agency.

Promotion of Competitive bidding: **Para 6.8** suggests that approved projects could be executed through Section 62 or 63 of the E Act. Since the cost and efficiency advantages of Section 63 (competitive bidding) have already been demonstrated, we suggest NEP should give a clear signal that all major projects should be executed through competitive bidding. This could be by providing a financial limit (of say Rs.100 Cr) beyond which, all projects should be under Section 63 as suggested below. Any essential exemptions to this could also be specified in the National Tariff policy.

The transmission projects as approved by the appropriate government(s) ~~would~~ shall be executed ~~either~~ through ~~regulated tariff mechanism under Section 62 of the Act or through~~ tariff based competitive bidding under Section 63 of the Act, if the capital cost is greater than Rs.100 crores.~~as to be notified by the respective government,~~ in accordance with the Tariff Policy of Government of India.

Uniform transmission pricing framework: **Para 6.9** mentions the CERC mechanism and suggests that "as far as possible", the InSTS mechanisms needs to be consistent with this. To encourage a fair development of the transmission system across the country, we strongly suggest a uniform transmission pricing framework for ISTS and InSTS. This principle could be stated in NEP and more details can be provided in the Tariff Policy.

Revision of guidelines for compensation for RoW: Suggestions on minimising RoW through higher voltages or conductor upgradation in **Para 6.10** are welcome. Since there are many pending cases in Courts and with regulatory commissions on this issue, NEP could suggest revision of the 2015 MoP guidelines for compensation for RoW[13] and its adaptation by all States, especially in areas like prior permission, estimating compensation and speedy grievance redressal.

Target year for separation of LDCs: Separate entity to operate NLDC, RLDCs and SLDCs were part of Sections 26(3), 27(2) and 31(2) of the EAct in 2003, but it has been taken 14 years to achieve this, in 2017 for NLDC and RLDCs.

NEP, in **Para 8.7** should provide a target year for setting up separate state company or corporation for SLDCs, say by 2023.

7 Distribution

7.1 Managing Agricultural demand and supply

It is crucial to have measures to reduce the cost of supply to agriculture and ensure sustained day-time power supply as envisaged in the solar feeder approach under KUSUM. Given the financial and social benefits, the policy should target universal coverage[14] of agriculture by solarizing agricultural feeders by 2030. Such an approach will not only provide quality power supply to farmers but also improve DISCOM financial viability. Universal coverage would contribute 75 GW to solar capacity, facilitate better grid integration by shifting demand to day time and through distributed deployment provide growth in rural jobs.

While 100% agricultural consumer metering is a desirable goal, there has been little progress despite repeated policy emphasis. It is critical to ensure energy accounting for the DISCOM is based on metered data from consumers or AMI on feeders and DTs. This is especially the case when even in states like

[13] https://powermin.gov.in/sites/default/files/uploads/RoW_Guidelines_15102015.pdf

[14] The weighted average price discovery at Rs 3 /kWh for solar feeder projects is significantly less than the APPC for DISCOMs, ~ ₹4/kWh. Hence there ₹1/kWh saving, translating to ~ Rs 13000 crore/year in avoided costs by 2030. This is without considering the additional savings from transmission charges of ₹0.4/kWh, avoided 9% losses (state transmission losses + 33 kV wheeling losses) and future APPC escalation. The fixed levelised tariffs under the solar feeder program lowers DISCOMs cost of supply, reduces the need for government subsidies and cross subsidies. This is crucial for the long term financial viability of DISCOMs.

Maharashtra (based on a study by a working group constituted by the regulatory commission[15]), meters were present only on 27% of agricultural consumers which were said to be metered as per DISCOM records. Further, where meter readings could be validated, more than 50% were found to be incorrect. Given this predicament, the focus of the policy should be on agricultural DT and feeder metering and rigorous assessment methodologies for unmetered and agricultural demand. This will provide a clearer picture of the extent of distribution losses[16]. Challenges of electricity supply to agriculture cannot be met by electricity sector actors alone, but requires an integrated approach, involving water, agriculture and electricity sectors. Factors like agro-climatic variations, irrigation efficiency, pumping efficiency and agriculture markets need to be taken into account[17].Towards this end, the following changes are suggested:

Amendment to Proposed Para 7.6

Further, increasing the solarization of agricultural pumps such as under PM-KUSUM scheme, <u>especially from solarised feeders under Component A and C</u> will not only help improve the quality of life of farmers by enabling irrigation during the day time but will also help in reducing the subsidy burden of State Governments. <u>Therefore, states should aim to provide power to 100% of grid connected farmers using solar feeder approach by 2030.</u> There are various modes of feeder segregation and each state should adopt a model best suited to it based on a cost-benefit analysis for implementation within the time frame. <u>However, priority should be given to feeder segregation capital works to enable feeder level solarisation under KUSUM Component A and C. While these measures address some concerns regarding electricity supply to agriculture an integrated approach is needed to meet the state specific challenges of agriculture supply by joint efforts of stakeholders in electricity, agriculture and water sectors.</u>

Amendment to Proposed Para 7.16

Despite the repeated emphasis on metering, Discoms are yet to achieve hundred percent metering of all consumers. The achievement in the agricultural sector is not satisfactory and requires attention on priority basis. Discoms should take necessary steps to achieve 100% <u>AMI</u> metering of <u>all agricultural feeders</u> ~~consumers~~ within one year of the notification of this Policy. <u>Estimation and approval of agricultural demand by the SERC should be based on sound analytical methods using agricultural feeder/ DT level AMI data and based on field surveys. The data used should be from within a three year time period, representative and from a large enough sample size. SERCs should also ensure complete transparency in estimation of AG sales by making all assumptions and data regarding this available on SERC website for public information and use.</u>

Similar amendments would be required in **Para 7.19**

[15] Maharashtra Electricity Regulatory Commission (MERC) formed a working group (WG) to study agricultural consumption in the state. As part of this study, working group undertook field survey of 1.33 lac agricultural consumers and detailed analysis of AMR / MRI feeder meter data of about 500 agricultural feeders. These observations are based on the survey results. The report is available here: https://www.prayaspune.org/peg/publications/item/457

[16]The report of the Maharashtra Electricity Regulatory Commission's (MERC) Working group (WG) for agricultural consumption study demonstrates that feeder AMI data can be used effectively by state regulators to re-state agricultural demand and distribution losses in the state. More details are available here: https://www.prayaspune.org/peg/publications/item/457. In fact, MERC relied on the analysis of the WG to re-state distribution loss from 14.7% to 20.54%.

[17] For more details please see: https://www.prayaspune.org/peg/publications/item/395-understanding-the-electricity-water-and-agriculture-linkages.html

7.2 Promoting Retail Competition and Consumer choice

Para 7.7 of the proposed NEP mentions various PPP models to improve efficiency, enhancing consumer satisfaction and improving efficiency. Given the limitations of cost-plus regulation, it is unlikely that a mere transfer of ownership would be sufficient to result in improvement of quality of supply, reduction in AT&C losses and reasonable pricing of electricity. The experience in Delhi[18], Odisha[19] and Mumbai[20] is particularly instructive in this regard. To foster efficiency improvement and protect consumer interests, it is critical to promote retail competition and consumer choice. Given that it would be impractical and unrealistic to introduce carriage and content separation as well as sub-licenses or delicensing distribution and bringing in multiple distribution companies, without necessary clarity in the legal, policy and regulatory framework, it is suggested that the policy provide impetus to promotion of sales migration through open access, captive and grid connected solar options. In FY19 about 18%[21] of energy consumption in large states in India was from open access and captive sales. With a framework to foster competition and protect DISCOMs from undue risk, consumer choice for all large consumers is possible.

Therefore, it is suggested that the existing Para 7.7 be replaced by the following:

Consumers with connected load greater than 1 MW currently have the option to choose their supplier either through open access or through investment in captive options. With increasingly economic viability of modular and scalable RE technologies, consumers are able to realise significant gains from switching supply source but this is limited to large consumers. Lack of clarity in processes, uncertainty in charges and lack of adequate compensation to the DISCOMs for facilitating retail competition has been constraining such choice. With concerted efforts from States and incentives from the Centre, it would be possible to meet 100% of demand from consumers above 100 kW through market options such as open access, captive, group captive and behind the meter generation (net metering or otherwise) by the year 2030. To facilitate this SERC' should:

Reduce open access threshold from 1 MW to 500 kW within six months of notification of the policy with further reduction in a phase-wise manner to 100 kW by 2025.

Cap and fix cross subsidy surcharge and additional surcharge to a sum of Rs. 2.5/unit for 5 years after which the surcharge should be gradually phased out, taking into context the state realities.

Stipulate frameworks to equitably compensate DISCOMs for services provided to kW scale grid connected rooftop solar systems, and ensure registration, and light regulatory oversight of behind the meter systems.

Further, State Governments should consider to increase levy of electricity duty on captive systems such that it is at par with the levy of cross-subsidy surcharge and additional surcharge on open access consumers. These funds should be used to compensate DISCOMs for losses.

[18] https://www.prayaspune.org/peg/publications/item/144
[19] https://www.prayaspune.org/peg/publications/item/118
[20] https://www.prayaspune.org/peg/publications/item/333
[21] Based on open access and captive data from regulatory filings and CEA reports for eight states in India.

Procedures and regulations for group captive consumers should also be stream lined to optimise generation costs and allow greater flexibility and choice for captive consumers.

Similar provisions should also be part of the National Tariff policy.

7.3 Role of demand aggregators

Para 9.4 mentions the creation of demand aggregators to allow those with load less than 1 MW to access markets. It is important to ensure that demand aggregators are not the only route for access to markets for small and medium consumers. Therefore, the eligibility limit for open access should be reduced in a phase-wise manner to ensure consumers have choice. Further, if demand aggregators are combining consumer demands and procuring power on their behalf, which is then supplied to consumers, the aggregator is performing the role of a trader. Thus, this activity should be licensed and regulated. However, if the aggregator merely performs the function of providing information to enable consumers to procure power and take on associated risks, it is acting as an OTC platform as specified in the CERC Power Market Regulations 2021 and should be recognized as such. Para 17.5 mentions that electric vehicle PCS can also use demand aggregators to purchase RE using open access. It should be clarified that in a few years such consumers can avail open access themselves with reduction in the eligibility limit for open access and that such consumers can also use virtual net metering options to procure RE.

Para 9.4*: A new entity called aggregators may be created to aggregate demand, renewable power generation, demand response, micro-storage etc. to help small consumers, prosumers and producers reach the market. Such entities would have to register as a trading licensee or an OTC platform as per prevailing regulations depending on services provided. While eligibility limits for open access should reduce over time, ~~T~~this would also help in promotion of open access in the interim ~~which is presently allowed for consumers with a load of only 1 MW and above~~.*

Para 17.5: *Full potential of environmental benefits of electric mobility will be realized when use of renewable energy for charging is maximized. To facilitate this, aggregators may be allowed to aggregate demand of several PCS to purchase renewable energy using open access. Virtual or aggregate metering options can also be availed by such consumers.*

7.4 Time of day (ToD) tariffs and demand response

Para 7.18 details the need for incentives for demand response measures for smart meter consumers. While incentives and framework for demand response is necessary, it is crucial that signals are provided to shift load even before full-scale roll out of smart meters takes place. Towards this end, the NEP could support levy of ToD tariffs for all consumers with connected load > 10 kW by 2023. NEP itself recognises the importance of time of day tariffs in Para 17.2 in the context of new loads such as EV charging. With costs of meters with ToD capability reducing substantially, the shift can take place without significantly burdening the DISCOM or consumers. Further, SERCs should specify ToD based incentives and penalties that vary on a seasonal basis. Such signals for load shifting to will greatly aid integration of renewables in the system and reduce impact of new demand sources such as cooking, EVs etc.

Para 7.18: *All consumers with connected load > 10 kW will be subject to Time of Day (ToD) tariffs by 2023. SERCs shall approve ToD incentives and penalties which vary seasonally to account for change in load and supply profile. In addition, incentives for demand response also shall be notified by all SERCs.*

Similar provisions should also be part of the National Tariff policy.

7.5 Smart, Prepaid Metering for consumers

Para 7.17 emphasizes the need for universal smart pre-paid consumer metering. However, there has been no comprehensive evaluation of impact of the existing smart metering adoption efforts on billing costs, meter reading expenses, collection efficiency, distribution losses, change in consumer complaints, response time to failure and implementation issues (such as the challenge of establishing sustained communication with rural locations). Universal roll out at this stage without incorporating learning from pilots runs the risk of investments not bearing fruit. Instead, it is suggested that the policy should provide for several pilots in various geographies and consumer profiles to enable learning and smooth rollout in the future. Para 17.17 stipulates that all meters (whether smart or not) be pre-paid within 3 years of the notification of the policy, presumably FY24. While there are possible operational and financial benefits of switching to a pre-payment, it is not clear if pre-payment would be the best mode of operation for all consumers (say, an HT consumer with 100% collection efficiency). To ensure smooth implementation and realize the ultimate goal of better collection efficiency and accurate energy accounting, the policy should provide a more flexible framework. Deployment of pre-paid smart meters can be prioritised in high loss areas. As most pre-paid smart meters retain the technical feasibility of operating in pre-paid/ post-paid modes, consumers with good bill payment histories can be given the option to switch to post-paid on request. Given the investment requirement for smart-metering efforts and the multiple parties involved, SERCs should specify a framework for cost-recovery from tariffs, scheme evaluation and for ensuring security and privacy of smart meter data.

Para 7.17: *The use of automation and smart metering can play a pivotal role in bringing the positive transformation in the distribution sector. Smart meters have advantages of remote metering and billing, implementation of peak and off-peak tariff and demand side management through demand response. To assess benefits, DISCOMs should ensure multiple pilots in their supply area in various locations and across consumer categories with documentation of implementation issues within 2 years of the issuance of this policy. The pilots should be large enough to cumulatively cover at least 5 to 10% of the consumer base in the state. Deployment of pre-paid smart meters can be prioritised in high loss areas of the DISCOM. The shift to the pre-paid system ~~will~~ can possibly address ~~do away~~ ~~with all some~~ problems associated with meter reading, billing, collection and disconnection in case of non-payment. Consumers with good bill payment histories in the area with pre-paid systems can be given the option to switch to post-paid on request. ~~All new electricity connections should be released with smart pre-paid meters/simple pre-paid meters. Further, existing meters should also be replaced with pre-paid meters in a phased manner so as to achieve 100% pre-paid metering within 3 years from the date of issuance of~~*

~~this policy.~~ <u>Smart meter rollout in any form should take place after approval is provided by the State Commission. Before any rollout, the SERC must specify a framework to assess benefits against costs and investments incurred which can be the basis for cost passthrough in tariffs.</u> The State Commissions should also put in place an independent third-party meter testing arrangement <u>and framework for privacy and security of smart meter energy consumption data.</u>

Similar provisions should also be part of the National Tariff policy.

7.6 Demand forecast and power procurement planning

Para 7.13 and 7.14 regarding demand forecast and power procurement planning should be reviewed on a periodic basis and the rolling plan should be approved by the State Commission. As RE and new technologies will play a significant role in shifting demand in the future, this should also be accounted for in the plan.

Para7.13: *Demand forecasting by the distribution utilities should be done under various time horizons and also on season-wise basis to decide on long-term, medium terms and short-term power procurements. <u>The forecast should be based on load duration curves, capacity value of RE in each time block and potential contribution of electric vehicles, sales migration, rooftop solar, solarisation of agriculture and high load residential appliances like air conditioners and water heaters.</u> After analyzing the expected load curve, procurement decisions regarding base load capacity and peaking capacity should be taken. The distribution utilities should acquire technological tools of load forecasting, portfolio management etc. for operational planning. <u>The demand forecast and the power procurement plan must be approved by the State Commission.</u>*

Para 7.14: *The State Commissions need to ensure that Distribution licensees tie up adequate supply to meet anticipated demand <u>for the next five years</u>, which ~~may~~ <u>shall</u> be reviewed as an Annual process <u>with public consultation. There should be a review of capacity in the pipeline in this process where the requirement of pipeline projects (especially those in the planning stage and obtaining approval stage) is reconsidered and evaluated based on alternate options and prevailing demand supply scenario.</u> Distribution licensees shall prepare a power portfolio management policy <u>(including RE and storage, short-term power procurement strategies, management of surplus capacity)</u> and get it approved by the State Commissions.*

7.7 Distribution planning and operations

Para 7.9, details the need for a Distribution System Operators. With increased decentralization and proliferation of RE systems, focus on distribution operations is paramount. Circle level distribution SCADA systems will enhance real time operations of the DISCOM and should be provided government support. Such a system would need to be in sync with meter data management efforts under smart metering and would be required even if there is no carriage and content separation. Support would also be necessary to continue to efforts of consumer indexing and mapping after IPDS. Para 7.13 specifies that five year distribution plans should be prepared in consultation with CEA. Given that the regulatory commission has processes for investment planning and cost approval, it would be appropriate if the plans are prepared in consultation with the state government, state transmission utility and other DISCOMs in the state, approved by the state commission and shared with CEA.

Para 7.9*~~: Distribution System Operator (DSO) for real-time operation of the Distribution System needs to be introduced.~~ Circle-level Distribution SCADA systems must be implemented by the utilities as a tool ~~with the DSO~~, on a priority basis, to facilitate creation of network information and customer data base and to help in the management of load, improvement in quality, detection of theft and tampering, customer information, manage distributed generation, embedded consumers and also for prompt and correct billing and collection, grid security. Support under central government programmes will be provided to enable this. ~~The DSO would play a major role in dealing with distributed generation resources like roof- top solar PV power connected to the grid, to ensure security and reliability of supply to consumers as well as the security of the grid. DSO may be made a separate and independent entity if separation of carriage and content takes place.~~*

Para 7.10: *The Government of India is providing support for the same to the states through information technology based systems under the IPDS program and will continue to do so in future programs.*

Para 7.13: *Discoms should prepare their distribution plan for next five years in consultation with the state government, STU and other DISCOMs in the state. Such plans accounting for capital investments, demand growth, retirement and replacement of assets, technology adoption and shall be approved by the SERC and shared with CEA.*

7.8 Periodic Energy audits

While metering is given significant importance, it is equally critical that periodic submission of energy audits takes place. The NEP, in a similar process as suggested in the draft Bureau of Energy Efficiency (Manner and Intervals for Conduct of Energy Audit (Accounting) in electricity distribution companies) Regulations, 2021 could stipulate that DISCOMs conduct an annual energy audit which is certified by an accredited BEE empaneled energy auditor and approved by the State Commission.

To this effect, Para 7.19 should be re-worded:

"...As the metering of all Distribution Transformers is essential for accurate energy auditing & accounting, efforts should be made by all Discoms to complete the metering of distribution transformers within next 3 years' time. Each distribution company shall submit energy audit for every financial year within five months of the completion of the financial year to the SERC for approval. The audit submitted must be certified by an empaneled BEE energy auditor. There shall not be a gap of more than 12 months between two annual energy audit submissions. In addition, quarterly and annual audits must be submitted to CEA, MoP, BEE, the State Commission and be available on the DISCOM's website..."

7.9 Quality of Supply and Service to consumers

Para 7.12 mentions the SoP regulations by SERCs and the recently announced Electricity (Rights of Consumers) Rules, 2020 to facilitate quality of supply and service to consumers. Having well intentioned rules and regulations are good first steps, but proper implementation requires clear direction and regular follow up. Quality of supply should also include prevention of electricity accidents, considering that the number of human fatalities due to electrocution has nearly doubled from 6,336 in 2003 to 13,432 in 2019. [22] Currently, CEA formulates the safety regulations. The State Electrical Inspectors along with DISCOMs are expected to ensure implementation. This arrangement provides limited transparency and participation, and no regulatory oversight. The NEP should suggest that SERCs are also involved in formulation and oversight of safety regulations, considering safety also as an important parameter in quality of supply.

Based on our recent submissions to Ministry of Power and MERC[23], we suggest the following addition to **Para 7.12.**

In order to gather consumer feedback, periodic surveys and special public hearings on quality of supply should be conducted. Instances of deterioration of quality due to force majeure events should be reported in detail for better accountability. Smart meter and smart grid data should be used to gather supply and service quality information, and implement automatic compensation. SERCs should periodically revise SoP regulations based on third party verification of SoP performance reports and ensure that the performance benchmarks are tightened and compensation raised, on a periodic basis. SERCs should set similar quality of supply and service benchmarks for rural and urban consumers by 2024. All state commissions shall be consulted in the drafting of CEA Safety Regulations, which shall have a defined role for Commissions in ensuring compliance.

7.10 Affordability for small consumers

With the average cost of supply at Rs. 7/unit, rising at 6% per annum, DISCOM tariffs are uncompetitive as compared to alternate options[24]. Large consumers especially commercial and industrial consumers are able to exercise choice and reduce their dependence on the DISCOM. However, small residential consumers and enterprises would have to continue to rely on the relatively high cost power supplied by the DISCOM to meet demand. With sales migration, the expenses to be recovered from the remaining pool of consumers would increase and many would be unable to pay for supply at cost. This is a major concern as domestic tariffs have been rising significantly in many states. Thus, it is critical to ensure tariff support is provided to small consumers who cannot pay for power at cost of supply.

Towards this, NEP can specify the following in Para 7.22, 7.23 and 7.24:

7.22 All consumers using less than 360 units per year should avail concessional tariffs at less than or equal to 50% of the average cost of supply. Concessional tariffs can be provided if the annual consumption in the previous year was less than 360 units to ensure consumers do not lose concessions due to increased consumption in some months.

[22] For more details, please see: https://ncrb.gov.in/sites/default/files/accident03.pdf, https://ncrb.gov.in/sites/default/files/ADSI_2019_FULL%20REPORT_updated.pdf
[23] https://www.prayaspune.org/peg/publications/item/469 , to MERC December 2020: https://www.prayaspune.org/peg/publications/item/482.html
[24] https://www.prayaspune.org/peg/publications/item/377

7.23 Domestic consumers using less than 100 units per month and LT commercial, industrial consumers using less than 200 units per month should have average tariffs less than the average cost of supply.

7.24 LT commercial or industrial consumers with connected load less than 10 kW using less than 2400 units per year (200 units per month on average) can be charged the same tariffs (fixed and energy charge), increasing telescopically as domestic consumers. This will protect small, home-based enterprises from undue harassment due to unauthorized use.

Similar provisions should also be part of the National Tariff policy.

7.11 Subsidy provision through DBT

Para 7.21 mentions that all subsidies should be through direct benefit transfer (DBT). Owing to the far-reaching impacts of DBT to consumer bank accounts, large and varied pilots should be undertaken before mandating universal adoption. Toward this end, the scheme should be implemented in a phase-wise manner over five years, and in the interim, DBT pilots, with emphasis on learning and addressing various implementation challenges should be encouraged.

Further, **the NEP in Para 7.21**, can also clarify that the DBT is to consumer accounts with the DISCOM rather than their bank accounts.

If the State Government desires to grant any subsidy to any consumer or class of consumers in the tariff determined by the SERC, the same shall be in the form of Direct Benefit Transfer (DBT) to the consumer's account with the DISCOM. For DBT to the consumer's bank account, DISCOMs should ensure multiple pilots in their supply area in various locations and across consumer categories with documentation of implementation issues within 2 years of the issuance of this policy. The pilots should be large enough to cumulatively cover at least 5 to 10% of the consumer base in the state.

Similar provisions should also be part of the National Tariff policy.

7.12 Accountability for DISCOM's financial performance

Timely recovery of costs, transparent accountability for short-term borrowing and time-bound resolution of accumulated losses and pending dues (including subsidy payment) are critical to ensure financial viability of the DISCOMs.

Towards this end, the following change in Para 7.8 is suggested:

The regulatory commissions should ensure that all the reasonable and legitimate costs are accounted for in the tariff without taking recourse to regulatory assets. Any regulatory asset or cumulative revenue gap approved by the Commission in a year should be resolved (either through state government take-over, grants, tariff increase etc.) within three years of its creation or addition, failing which it is to be disallowed by the regulator. ~~Tariffs determined by Regulatory Commissions should be able to finance necessary CAPEX to be undertaken by Discerns for improving the quality of supply.~~ The Regulatory Commissions should ensure that tariff petitions are filed in time and processed expeditiously so that new tariffs could be made applicable w.e.f. the very first day of the following financial year, enabling the *utilities to recover full revenue during each financial year. Regulators should also specify framework for timely recovery of fait accompli charges through fuel surcharge mechanism. The levy of surcharge should be ensured in every billing cycle by the DISCOM. Trueing up of accounts of the utilities should be done at the earliest possible to ensure that unnecessary carrying costs are not allowed to inflate tariffs. Pending subsidy payments along with interest due to delays should be accounted for separately by State Commissions such that the payment due along with interest charges are adjusted with future subsidy payments. SERCs should notify regulations for annual submission of crucial and critical data by utilities every year independent of the tariff process. This will ensure performance accountability even if there is no tariff petition filed by the licensees and will also ensure adequate data with the Commission to initiate suo motu tariff determination and true-up processes. The data submitted on an annual basis should be made public and also be shared with the Ministry of Power and Central Electricity Authority.*

Similar provisions should also be part of the National Tariff policy.

8 Strengthening Regulatory Governance

With technology-led disruptions and structural changes in the sector, regulatory commissions will need to play a prominent role in ensuring accountability of utilities, protecting consumer welfare and facilitating equitable risk sharing. Towards this end, Para 2 and Paras 10.1. 10.2 and 10.3 should strengthen the mandate of the regulator rather than weaken the institutions' ability to safeguard consumer interest and promote sector reform. Given the rise in cost of supply at 6% per annum and the non-competitiveness of DISCOM tariffs, it is also crucial that regulatory frameworks move away from the cost-plus paradigm towards inflation and efficiency linked cost escalations, performance linked RoEs and norm-based cost-passthrough.

The following changes are suggested in Para 2 and Paras 10.1 to 10.3:

Para 2: *(vi) Move ~~towards light touch regulation~~ away from cost plus regulation towards better performance accountability*

Para 10.1*: Regulatory Commissions should adopt regulatory process consistent with the policy of gradually moving away from cost-plus regulation towards incentive based regulation and price cap regulation ~~towards light touch regulation~~. As more and more power, especially renewables is procured on competitive basis either through power exchange or through bidding, the burden of regulatory Commissions in tariff ~~setting~~ determination would come down. Even in cases where tariff is to be ~~fixed~~ determined by the regulatory Commission, they should follow performance based cost of service regulations with multi-year tariff (MYT) where there are incentives and penalties to ensure timely completion, prevent cost-over-runs and reduce inefficiencies ~~as laid down in the Tariff Policy~~. The performance and cost benchmarks for evaluation of cost plus projects shall be adopted from performance of competitively bid projects. The Regulatory Commissions should also focus ~~more~~ on ~~emerging~~ tasks such as market monitoring and surveillance, ensuring resource adequacy, balancing, tariff design challenges, accountability for supply and service quality, demand response etc.*

Para 10.2: *Forum of Regulators may evolve procedures for move* ***<u>away from cost plus regulation towards incentive based regulation</u>*** *~~towards light touch regulation~~. For example, <u>O&M costs can be linked to inflation, cost passthrough for crucial performance heads shall be norm based, a proportion of RoE shall be allowed conditional to achieving performance milestones.</u> ~~certain pass-through costs may be get added to tariff after calculations are carried out based on pre-defined formula or algorithm and shared with stakeholders in a transparent manner.~~*

Para 10.3: *Wherever power or transmission service is being procured based on guidelines issued by the Central Government under Section 63 of the Electricity Act, 2003, the role of Appropriate Commission is primarily <u>to approve changes to bidding process, scrutinise and approve discovered tariff and</u> ensure <u>enforcement of contract</u> ~~compliance to the process~~. It needs to be ensured that regulations framed by Appropriate Commission are aligned to the aforesaid guidelines or Standard Bid Documents issued thereunder. ~~In such cases, only those claims or disputes that do not get settled in accordance with the provisions of the contract, should be referred to the Appropriate Commission.~~*

Similar provisions should also be part of the National Tariff policy.

9 Enhancing informed consumer participation in regulatory process

Decision making in the sector, especially before the Regulatory Commission needs to be agile and clear in the face of uncertainties due to various disruptions in the sector. However, this should not be at the cost of public participation. Regulatory Commissions should have a clear mandate to increase transparency and informed public participation. In order to improve the participation of consumers in improving the quality of service, we suggest that a new paragraph on capacity building of consumer groups, similar to Para 5.13.4 of NEP (2005) be inserted.[25] This paragraph can also strongly encourage Regulatory Commissions to set up the institution of Consumer Representative as per Section 94(3) of E Act, and already implemented by some Commissions.

In this regard, the following provisions should be added to the NEP **after Para 10.3**:

<u>10.4 State Commissions should conduct a separate process to review compliance to Standards of Performance regulations and review status of metering and billing, supply hours and other supply and service quality related parameters. Based on this annual review, the Commission should provide directions, disallow costs or levy penal provisions as appropriate.</u>

<u>10.5 In addition to tariff processes and grant of licence, public consultation including public hearings shall be undertaken by state commissions for approval of power procurement plans and tariff adoption for projects under Section 63. Public hearings should be conducted for annual review of supply and service quality (compliance to SoP regulations, CEA safety regulations and service related directives), major capital investment, franchisee agreements as well as modification or revocation of licence.</u>

[25] Section 5.13.4 of NEP (2005): "The Central Government, the State Governments and Electricity Regulatory Commissions should facilitate capacity building of consumer groups and their effective representation before the Regulatory Commissions. This will enhance the efficacy of regulatory process."

10.6 The Central Government, the State Governments and Regulatory Commissions should facilitate capacity building of consumer groups and their effective representation in regulatory proceedings. Section 94 (3) of the Act provides for appointment of authorised consumer representatives, to enable representation of public and consumer interest in all proceedings of the Commissions. Commissions should prepare suitable regulations for selection of consumer representatives, detailing their role in contributing to regulatory proceedings and appoint representatives within six months of notification of the policy. The Commission can also stipulate a separate fund for training and capacity building of consumer representatives.

Many crucial proceedings where consumer interests should be represented take place before the APTEL where consumer access is limited due to prohibitive fees and lack of permanent functioning benches. Pl. refer Prayas paper "Amicus Populi? A public interest review of the Appellate Tribunal for Electricity"[26]

To protect and represent consumer interest before the tribunal, the **NEP can specify in Para 10.7 that**:

Along with regulatory commissions, the appellate tribunal for electricity should also protect consumer interest in matters before it. The tribunal must ensure operation of its regional benches. In matters where there is potential impact on a large number of consumers, the tribunal must appoint amici curiae and empanel a few experienced and public-spirited advocates to specifically represent the interests of consumers and the public at large in specific cases. For small, individual consumers and consumer organisations APTEL should dispense with fee requirements or specify a nominal fee similar to the fee of High Courts so as not to deny access to proceedings before it.

10 Energy Conservation and Energy Efficiency

The state governments, DISCOMS and central agencies need to work together towards improving the efficiency in the sector. Necessary incentives and equally necessary monitoring and verification mechanisms will make energy efficiency an important strategy in reducing demand.

Para 13.1*: The SERCs must mandate utility driven DSM programme and customer engagement as a means of peak load management, energy conservation and saving cost of power. Forum of Regulators (FoR) published model Demand Side Management (DSM) Regulations in 2010. Several SERCs have adopted these regulations. However, neither the model regulations nor the state regulations have been updated over the time. Furthermore, only few states have regulations to assess cost effectiveness of the DSM programme and no state regulation have provisions for evaluation, monitoring, verification (EV&M) of DSM programmes. FoR shall publish revised model DSM regulations which includes provisions for assessing cost effectiveness and EVM of DSM regulations. SERCs should adopt the same.*

Para 13.2*: As of 2020, the programme covers 26 appliances out of which 10 are under the mandatory regime and the remaining 16 under the voluntary regime. BEE should provide a timeline for shifting 16 appliances under the voluntary category to the mandatory category. BEE should also continue to provide the timeline for the revision of standards. Any deviation from the timeline should be supported by data*

[26] https://www.prayaspune.org/peg/publications/item/393-amicus-populi-a-public-interest-review-of-the-appellate-tribunal-for-electricity.html

and evidence that justifies the delay. This should be made public on BEE's website. The credibility of the Standards and Labeling Programme is dependent on consumer trust. In order to build trust, BEE should publish an annual report on the compliance with the standards as observed through surveys and random check testing of the appliances.

11 Other issues

11.1 ICT and Cyber security

With the increasing role of smart metering and power trading, the need of integrating such technological advancements in the distribution system is gaining importance. In fact, a recent ransomware attack on the US gas pipeline operator, Colonial pipeline forced the United States Government to declare a state of emergency[27]. This highlights the urgent need to invest in cyber security for the entire system. Similar incidents have taken place with WBSEDCL[28] (2017), TSSPDCL (2019)[29] and some RLDCs/SLDCs (2021)[30] which calls for action in this regard. All utilities shall prepare a plan and define procedures to ensure detection of different types of security events in real time. Such plans should be submitted for regulatory approval on a periodic basis. Utilities should also prepare a cyber-security Standard Operating Procedure (SOP) which will include details such as periodic checks/audits, threat tracking and assessment protocols as well as information sharing guidelines.

11.2 R&D institution and financing

There is a need to develop a Power Sector R&D wing in the state power department which shall work with DISCOMs, LDCs, EDA, STU and other state-specific stakeholders. As R&D is important for future power sector innovation, all companies in the sector, rather than just large profit making companies (as mentioned in Para 11.6) should ensure budgetary allocation and staff for R&D.

11.3 Skill Building and Human Resource Development

Draft NEP highlights the need to strengthen training in the field of electricity distribution, regulation, trading and power markets. It also calls for reviewing the skill set of personnel in statutory bodies like CEA, CERC, STUs, CTU, LDCs, etc. to align with new requirements.

While we appreciate this, some important stakeholders have been left out, which are consumers and consumers' representatives and Consumer Grievance Redressal Forums (CGRF and Ombudsman). Reskilling and capacity building of such an important stakeholder at a wider scale is very important to strengthen the public participation in policy making and other key areas.

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[27] https://www.cnbc.com/2021/05/10/biden-prepared-to-take-additional-steps-after-colonial-pipeline-ransomware-attack.html

[28] https://www.reuters.com/article/cyber-attack-india-idINKCN18B1NE

[29] https://timesofindia.indiatimes.com/city/hyderabad/ts-power-utilities-websites-hit-by-ransomware-restored/articleshow/69173216.cms

[30] https://www.livemint.com/industry/energy/chinese-state-sponsored-red-echo-group-targeted-india-s-power-infra-govt-11614597716939.html

11.4 Disaster risk reduction

Given the proliferation of unprecedented disasters, especially driven by climate change, the need of all licensees and generating companies to comply with CEA's Disaster Management Plan for Power Sector[31] (Jan 2021) seems adequate. However, the need for disaster resilient infrastructure and reducing disaster risks and the need for state-specific strategies cannot be neglected.

Hence, Para 19.3 can be reframed:

All the licensees and generating companies must comply to the provisions of Disaster and Crisis Management Plan prepared by the Central Electricity Authority. <u>*States should develop Disaster Management Plans for the Power sector with public consultation within a year of notification of this policy. For this, they may refer to the Disaster Management Plan for the Power Sector prepared by the Central Electricity Authority. The plans prepared by the state should be complied by all licensees and generating companies within the state. All other licensees and generating companies should comply with the Disaster Management Plan for the Power Sector prepared by the Central Electricity Authority.*</u>

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[31] https://cea.nic.in/wp-content/uploads/page/2021/01/DMP_January_2021.pdf