PEG Comments on CEA's draft National Electricity Plan (Vol 1), 2022-27

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The National Electricity Plan prepared by the CEA is a crucial guiding document for the electricity sector. It serves as a reference for key sector trends and helps various stakeholders, such as generating companies, transmission utilities, and distribution licensees, with medium and long-term planning. Towards ensuring a robust NEP and enhancing transparency in the proposed guidelines, Prayas (Energy Group) has the following comments:

1. Need to revise draft NEP based on 20th EPS projections and finalise based on public consultation

Given that planning is essential toward ensuring the health of the electricity sector, especially in light of the fast paced changes it currently faces and is poised to face, the NEP must be a robust document. Since the publication of the draft NEP, there have been several developments, such as the finalisation of the 20th EPS, which merits revision of the draft NEP itself. Owing to the impact the NEP has on the decision making process of stakeholders across the sector and to ensure transparency of process, the revised draft of the NEP must also be subject to public consultation and review before finalisation. The CEA has also recognised the importance of such consultative processes, and provided time for the submission of stakeholder comments.

2. Transparency in modelling studies and scenarios considered:

Energy models are a good, and increasingly necessary, tool for demand and supply projections in the electricity sector. The draft NEP includes the use of models such as ORDENA and PLEXOS for generation expansion planning. While this is a step in the right direction, there are several measures to be taken toward improving the efficacy of the modelling exercise. This can be considered while revising the draft NEP.

a. Open source modelling: It is understood that such modelling exercises contribute to important decision making. This makes it necessary to develop transparent models, where all the steps in the process are open to public scrutiny, so that stake holder participation and public review is ensured. Thus, open-source tools with public documentation on model formulation, along with the methods and algorithms utilised are preferred over black box models.
b. Public availability of input parameters: The modelling studies are only as good as the input data and assumptions. Hence, it is important that these inputs can be vetted carefully by all stakeholders. The input data used and the assumptions made for all the scenarios involved should be clearly elaborated and made available to the public.
c. Broader scope of scenarios considered: Currently, four scenarios are considered for generation expansion planning. Three of the four scenarios account for variation in deployment of capacity and one deals with projections on account of variation in demand. However, to better represent likely ground realities in the face of dynamic changes on several fronts within the sector, the scenarios represented must cover a broader scope. The NEP must expand its considerations and include projections for

scenarios that account for variations in cost of technology, differing changes in demand, and variations in deployment of capacity.

Public availability and consultation of the models, input assumptions and scenarios is necessary toward assessing whether the proposed capacity mix for the years considered is optimal. Once such information is made public, the NEP should go through another round of public consultations, as discussed in comment #1.

3. Demand estimation

Currently, the demand projections considered in the draft document assumes a 6% CAGR for electricity requirement in both the five year periods (from FY22-FY27 and FY27 to FY32). In the 20th EPS, the growth rate of electricity requirement till FY27 is 7% and for FY27 to FY32 is 5%. As proposed in section 4.3 of the draft document, the projections of electricity demand should be revised to reflect the finalised 20th EPS demand projections. The growth rates in both the 20th EPS and the draft NEP are higher than the demand growth rates generally seen in the past. Therefore, as discussed above, it is important to run scenarios with lower demand to account for this possibility.

In addition to this, such revision of demand estimation will allow for accounting of the impact of several crucial sector changes on demand projections. For instance, several DISCOMs are seeing increasing sales migration through the open access and captive routes. Currently, the demand estimation used in the study does not include the impact of captive and open access capacity. Sales migration will have significant impact on DISCOM demand especially over a 5-10 year timeframe.

There are also proposals to introduce time-of-day tariffs to more consumers with the increasing penetration of smart meters, which could result in changes to demand profile. Simultaneously, schemes such as PM-KUSUM and other state level schemes results in increased solarisation of agriculture and demand shifts towards day time. Shifts in load are also likely to be caused by penetration of electric vehicles, push for uptake of green hydrogen, changing cooling demand, encouragement of induction-based cooking, behind-the-meter rooftop generation, and other such factors.

These factors affect demand differently and planning must include these impacts. It appears that the current models assume a demand shape that is similar to the current load shape – this may not be the case. A case in point is the 500 TWh additional new demand from green hydrogen as estimated by 20th EPS. The load shape of such a high new demand would be crucial towards generation planning. Therefore, the NEP models should be run for demand scenarios that account for these changing factors. Since these are significant changes, the NEP should go through another round of public consultations after its projections are revised based on the suggestions above, as discussed in comment #1.

In addition, CEA is in the process of finalising Resource Adequacy Guidelines, which requires utilities to estimate their demand on a regular basis. Therefore, this leads to two different methods of estimating demand and supply for the country. It is not clear how these two will be reconciled.

Further, as per table 3.3, the energy savings for utility and non-utility in the year FY27 ranges between 213-285 BU (moderate-ambitious scenario), the same for FY32 is 304-404 BU. However, the figures for projected energy savings in the major highlights section is 398.49 BU and 590.53 BU for FY27 and FY32 respectively. In addition to this discrepancy, the demand estimations discussed in the draft report should be net of these savings. However, it is unclear if this is indeed the case.

4. Fund and fuel requirement

Some aspects pertaining to fund and fuel requirement projections require clarification or further elaboration. These are as follows:

a. Model cost and CUF assumptions: It is not clear if the cost assumptions used in the modelling exercise (Annexure 5.1) are in real terms or in nominal terms. If they are nominal terms, assuming a flat cost trajectory for coal, nuclear, hydro and pumped storage may not be appropriate as they would increase with time. Similarly, it seems that a constant CUF has been assumed for solar and wind installations over the years, though CUFs have been steadily going up and are likely to further go up in future. In particular, the wind CUF assumed seems quite low.
b. Variation in capital cost per MW: Capital cost per MW has been tabulated for different generation sources in Annexure 5.1 as part of the financial parameters assumed for the modelling exercise. This, however, differs from the cost per MW assumed for estimating the capital cost of power projects in Annexure 8.1, as part of the fund requirement calculation. The reason for such varying consideration has not been discussed in the draft document.
c. Escalation considered for fund requirement: As per section 8.1.2, the estimation of fund requirement has been carried out by escalating the standard cost per MW estimates for various generation sources in FY22 at 2.65% p.a. With capital cost for BESS going from Rs. 8.75 Crore/MW in FY23 to Rs. 6.46 Crore/MW in FY30 and Rs. 6.81 crore/MW in FY32 (annexure 8.1), it is clear that these escalation rates have not been applied to BESS. This is in keeping with observed trends and literature on the reducing trend of capital cost for BESS. However, the cost escalation has been applied to solar and wind capacity, with the costs assumed to go from Rs. 4.57 Crore/MW to Rs. 5.33 Crore/MW for solar projects and from Rs. 6.16 Crore/MW to Rs. 7.79 Crore/MW, between FY23 to FY32. The assumptions behind such escalations are unclear, and are inconsistent with observed trends. Further, the financial parameters assumed in Annexure 5.1 include the capital costs of solar plants uniformly reducing from Rs. 4.5 Crore/MW in FY 22 to Rs. 4.1 Crore/MW in FY30, and remaining the same till FY32.
d. Variations in Specific Coal Consumption (SCC): The SCC for FY22 as calculated from Exhibit 7.6 of the draft is 0.69 kg/kWh. This worsens to 0.73 kg/kWh in FY23 (Table 7.3), 0.76 kg/kWh in FY27 (Exhibit 7.6), and 0.81 kg/kWh in FY32 (Exhibit 7.6). The reasons for assuming such high SCC are unclear, and the trend of rising SCC is puzzling, since older and more inefficient plans will retire and newer and more efficient plants would generate more. Rising SCC is also inconsistent with the discussion in chapter 10 about improving efficiency of coal-based generation leading to reduced emission factors for it.

e. Discrepancy in coal requirement calculation: As per item 9 of table 7.8 in the draft, the coal requirement is said to be calculated at a SCC of 0.67 kg/kWh plus 1% transportation loss. Using these parameters and the coal generation tabulated as item 1 of the same table, the coal requirement comes to 766.7 MT and 881.7 MT for FY27 and FY32 respectively. However, the values captured in the table are much higher at 871.5 MT for FY27 and 1058.2 MT for FY32. This overestimation in coal demand needs to be corrected.

5. Treatment of RE

RE is set to account for more than 50% of the total installed capacity and over 30% of likely gross generation by FY30. This growing role of RE is supported by economic and policy levers alike, and is in line with broader national targets for the power sector. Most of the new capacity addition (and incremental generation) would be coming from RE sources. Despite this, it is still treated differently from conventional sources in the draft NEP.

For instance, in chapter 2 of the draft NEP, capacity addition from RE from FY17 to FY22 is considered separately. Also, while the slippage and commission of conventional capacity in FY17 to FY22 is tracked, the same is not carried out for RE capacity. Likewise, in Chapter 10, the weighted average CO2 emission rate from grid-connected stations is given without considering renewables – though emissions reduction is one of the factors driving greater adoption of RE.

RE is an integral part of the power system, and its role is only going to grow. In order to assess the sector as a whole and allow for comprehensive planning, RE must be integrated with other generation sources, instead of being separately assessed. This comment also broadly applies to all CEA reports – including monthly generation reports etc. - in which RE is not reported at all, or reported as a footnote.

6. Missing data and discrepancies

In addition to points discussed above, there were the following lacunae in the draft NEP:

a. In section 5.5 it is stated that "*The peaking availability, auxiliary power consumption, heat rate for several types of generating units, as considered in the expansion planning studies are given in Annexure 5.1*". However, annexure 5.1 does not carry these details.
b. As per section 2.5, the reasons for delay of individual hydro and coal projects are elaborated in annexure 2.4. But project wise slippages are discussed in annexure 2.3 and the individual project delays are not captured in either annexure.
c. Section 10.5 discusses carbon emissions from the power sector, which should ideally deal with emissions of all GHGs. But it is unclear whether the section deals with the CO_2 equivalent of all GHG or emissions of CO_2 alone.
d. In Section 10.5, it is stated that "*The CO2 emission from gas based power stations is almost half of that is generated by coal based power stations*". This is not correct and what was perhaps meant was that the *CO2 emission factor* of gas-based stations is half of coal.
e. Some aspects of the draft NEP need to be updated to reflect recent changes. For example, the 2022 amendment to thermal power plant emission norms have been finalised. Also, BEE is already in the process of developing a mandatory carbon market.