BEFORE THE ANDHRA PRADESH ELECTRICITY REGULATORY COMMISSION

IN THE MATTER OF:

ARR Filings for Tariff Proposals submitted by APEPDCL and APSPDCL for FY2020-21

Submissions of Prayas (Energy Group), Pune

The Commission vide its public notices dated 6th December 2019 sought comments on the petitions filed by APEPDCL and APSPDCL regarding ARR and tariff determination for FY21.

Prayas (Energy Group)'s comments and suggestions in this submission are limited to the prayers and submissions of the DISCOMs with respect to variable renewable energy in their Aggregate Revenue Requirement and Tariff Proposal for the Retail Supply Business for FY: 2020-21 dated December 2nd 2019.

We request the commission to allow us to make additional submissions on this issue and other issues with respect to the current process before the State Advisory Committee meeting scheduled for the 13th of January 2020.

1 Need to ensure scheduling, forecasting and approval of VRE in ARR

The DISCOMs in their petition state that:

In view of variable nature of generation with a character of non-dispatchability, the availability from VRE sources has not been considered for Power Purchase Cost calculations. The energy from VRE sources cannot be scheduled for day ahead or week ahead planning. The generation from these sources is considered as inadvertent/infirm in nature. As such the generation from VRE sources will be used subject to its availability as per grid code.

The DISCOMs claim that renewable energy procurement is difficult to project as the generation is infirm and variable in nature. APERC has notified the APERC Forecasting, Scheduling and Deviation Settlement of solar and wind generation regulations in August 2017. Its stated objective is to, *'facilitate large scale grid integration of solar and wind generating stations while maintaining grid stability and security as envisaged under the state grid code through forecasting, scheduling and deviation settlement of these generators'.* Thus it is clear that wind and solar generation has been mandated to be forecast and scheduled on a day-ahead basis along with revisions on a 1.5 hour basis and appropriate penalties for deviation settlement also are in place.

In fact, APERC was first Commission in India to ensure that a framework is in place to ensure forecasting and scheduling of wind and solar resources. Many states have since notified similar regulations based on the model regulations notified by the Forum of Regulators. These regulations have also been implemented in Andhra Pradesh with compliance from wind and solar generators. Therefore the contention that it is not possible to schedule renewable energy power raised by the DISCOMs is not tenable.

The objective of the aggregate revenue requirement (ARR) and tariff process is to provide a reasonable estimate of aggregate costs and revenue to ascertain increase in tariff and subsidy required. This is to be done while holding the DISCOMs accountable for performance improvements and reducing cumulative and current revenue gaps. In order to ensure this estimate is reasonable and prudent, it is vital to account for all possible costs in the projections. This imperative is reiterated in the Tariff regulations and the order of long-term tariff principles notified by the Commission.

To ensure reasonable estimates, projections are made for various cost and performance heads knowing that there could be variation in the actual cost head at the time of true-ups. Despite severe challenges in projecting unmetered agricultural consumers the DISCOMs and the Commissions use specific consumption norms to project agricultural sales. Similarly, DISCOMs continue to forecast HT Industrial and Commercial sales despite the dynamic changes in open access and captive prices making such projections challenging. In addition, challenges with fuel availability would also make projection of generation from thermal sources difficult in the current context. However, over the years, both the DISCOMs and the ERC treat such projections as crucial part of the ARR estimates.

Further, on an annual basis, the projections for NCE and Renewable energy approved by the Commission based on the DISCOM's estimates have varied only between -5% to 1% from the actuals for the years FY17, FY18 and FY19. In sharp contrast, the variations between the approved estimates and the actuals for State and Privately owned thermal and hydropower plants is much higher. This is shown in Table 1.

Source of Power Purchase	FY 17	FY 18	FY 19
Andhra Pradesh Power Generation Corporation Limited (Thermal)	-32%	65%	13%
Andhra Pradesh Power Development Company Limited	-22%	-32%	-35%
Andhra Pradesh Power Generation Corporation Limited (Hydro)	-32%	-16%	-17%
Central Sector Generating Stations	-2%	5%	-12%
Andhra Pradesh Gas Power Corporation Limited	-25%	16%	78%
Gas based Independent Power Producers	30%	546%	31%
Other Independent Power Producers	-61%	-16%	-20%
Non-Conventional Energy	**-5%**	**-5%**	**1%**

Source: True-up petitions by the DISCOMs for FY17, FY18 and FY19.

Despite variations, costs estimations of thermal and hydropower plants are considered in the ARR as power purchase accounts for majority of the costs incurred by the DISCOMs. It is vital that a similar treatment be given to renewable energy power which seems easier to project than other sources.

As per the true-up filings of the DISCOMs for FY19, about 21% of the power purchase was due to non-conventional energy (NCE) sources, predominantly renewable energy sources. The share of NCE in previous years was also substantial at 17% of total energy purchased in FY18 and 9% in FY17. Given the commitment to increasing RE adoption and keeping in mind the RPO targets of the DISCOMs, purchase from renewable energy sources will continue to increase. Not accounting for this power along with its costs would severely underestimate power procurement costs and consequently revenue gaps. These costs would eventually be incurred during the year when must-run renewable energy power is used. The incurred costs would be then recovered from consumers subsequently in the form of higher revenue gaps during true-ups along with avoidable carrying cost burden. To ensure this does not occur, the Commission should insist on ensuring projections for purchase from RE sources are accounted for in the current process as well as future tariff processes.

2 Need for clarity on VRE integration costs proposed by the DISCOM

As per the petition, *'The VRE integration costs are calculated based on CEA Reports on optimal energy mix in power generation (page 20) and Optimal location of various types of balancing energy sources (page 13).'* It is made up of three parameters (adequacy, balancing and grid integration costs).

2.1 Tenability of adequacy costs and issues with its estimation methodology

*The **adequacy cost** is computed as a differential cost between Weighted Average RE Tariff and the weighted average Thermal variable Cost.*

Procurement of renewable energy capacity is expected as per the mandate under the Electricity Act (2003), the APERC RPO regulations and in line with state wind and solar policies. Regulator has allowed cost passthrough for all prudent expenses and this includes costs due to RE procurement. Therefore the treatment of such costs with respect to revenue recovery through tariffs, subsidies and regulatory assets should be the same as other costs passed through by the ERC. The CEA report quoted by the DISCOMs also states that *"even after including the financial implication on account of variable renewable generation, it would still be cheaper in the future to set up renewable generation capacity, as compared to coal-based capacity".*

Therefore the relevance of quantifying such transient opportunity costs is unclear, especially when new wind and solar capacity is available at less than Rs. 3/ unit.
The DISCOM in order optimise power procurement can take proactive steps to sell surplus power (VRE and thermal) using medium and term and short-term options as applicable. Therefore, there is no requirement for additional dispensation in the name of adequacy costs.

In addition, there are certain methodological issues with estimation of adequacy costs as described in the petitions. The term 'adequacy cost' is not defined in the petition. Even if one were to interpret this as the higher cost due to backing down cheaper coal with lower variable cost and dispatching higher cost must run renewables (point 4, table (TN Summary), pp. 15 in the CEA report[1], there are several methodological issues with the proposed calculation.

a. First, one would have to establish that there was spare available coal generation capacity which was backed down specifically to integrate VRE. Backing down can take place due to a variety of reasons including expected changes in diurnal and seasonal load and unexpected changes in load (due to sales migration, change in consumption patterns), weather etc. One would also have to establish that such coal capacity procurement was justified for reasonable load growth expectations based on scientific demand assessments.

b. Second, the highest variable cost coal generation at the margin (as per MoD) would be backed down first and hence instead of using the '*weighted average Thermal variable Cost',* one would have to consider VC of the actual unit being backed down. The calculation considers *'The actual pooled variable cost is considered as Rs 3.2/Unit for H2 of FY 2019-20 and Rs 3.54 /Unit for FY2020-21.'* However, as per the DISCOM submission in the current petition, there are various plants with higher VC for FY 2020-21 (RTPP – 4.25/kWh, VTPS – 3.67/kW, NTPC Simhadri – 3.71/kWh, Vallur – 4.15/kWh, Kudigi – 4.38/kWh etc.). Therefore using the weighted average variable cost of capacity whose backing down is attributable to VRE generation would be methodologically correct.

2.2 Using CERC methodology for levy of balancing costs

The petitions state that:

The ***balancing cost*** *is due to increase in specific coal consumption and increased oil consumption while operating in ramped down condition; and reduced coal plant life etc. due to frequent ramp up/ramp down or start/stop operations.*

Firstly, the calculation of 0.53/kWh as the balancing cost is not explained in the petition.

There is certainly a valid increase in cost for coal generation due to part load operation. This needs to be accounted for and compensated promptly. The fourth amendment to the IEGC by CERC in 2016 has already put in place a comprehensive mechanism for CGS and ISGS plants to compensate them for higher heat rates, higher auxiliary consumption and higher oil consumption. Specifically, as per 6.3B (3)

> *Where the CGS or ISGS, whose tariff is either determined or adopted by the Commission, is directed by the concerned RLDC to operate below normative plant availability factor but at or above technical minimum, the CGS or ISGS may be compensated depending on the average unit loading duly taking into account the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis duly supported by relevant data verified by RLDC or SLDC, as the case may be.*

[1] Report of The Technical Committee On Study of Optimal Location of Various Types Of Balancing Energy Sources/Energy Storage Devices to Facilitate Grid Integration of Renewable Energy Sources and Associated Issues

In line with the CERC framework, APERC should make amendments in their grid code to adequately compensate state coal generators for this purpose.

2.3 Need for detailed studies before attributing grid integration costs

As per the DISCOM petitions:

Grid integration cost *is due to the wasted evacuation and network infrastructure created for the < 25% PLF VRE plants. 75% of evacuation infrastructure remains under utilized and the fixed cost is paid unnecessarily by APTRANSCO and to PGCIL by way of PoC charges. The APTRANSCO charges are not included in the network expenditure.*

The methodology and assumptions used for the calculation of 0.41/kWh as the grid integration cost is not explained in the petition.

While it is certainly true that CUFs for wind and solar plants are much lower than coal power plants, the proposed calculation is too simplistic in its formulation.

Firstly, transmission is built for reliability (under N-1, N-2) conditions and hence is always underutilised to some extent. Its usage is never 100%. A significant number of ISTS lines have very low loading in the range of 30-40%(ref). Also, the 25% CUF applied for wind and solar plants is valid only for the last mile dedicated connectivity to the pooling sub-station after which it is impossible to attribute usage of transmission lines specifically to any generation plants or loads without load flow studies. Hence while this is a valid point, detailed load flow studies need to be carried out to actually find the true incremental cost of wind and solar. Therefore, before such costs are levied, the Commission should commission such studies for the Andhra Pradesh context.

2.4 All instances of backing down and operational inefficiency in thermal generation currently attributed to VRE

While calculating the total integration costs, (adequacy, balancing and grid integration costs) they are implicitly assumed to **fully** apply to all 13,193 MU of wind and solar power being considered. This would mean that for each instance of wind and solar generation, there was spare and cheaper (VC) coal generation available which was backed down and that coal was operating at part load with higher heat rate, oil consumption and auxiliary consumption for every instance of wind and solar generation. This is highly unlikely and has not been demonstrated through any serious and comprehensive modelling exercise.

In addition, principles used for levy of adequacy cost and balancing cost are valid not only for RE but for backing down and part load operation of coal for other reasons including load shapes, low demand, sales migration etc. It also needs to be clarified if such costs would be calculated and attributed for such instances.

3 No regulatory approval for VRE/MRI subsidy

The DISCOMs have proposed the levy of a Variable Renewable Energy (VRE) or Must-Run Incentive (MRI) subsidy to be given by the state government to renewable energy developers. This subsidy is to be provided to compensate the renewable energy developers for payment to DISCOMs for the adequacy costs and balancing costs incurred for utilisation of the VRE asset.

The issues with the complex arrangement proposed by the DISCOMs as well as the estimation of the various costs to determine the subsidy is discussed in the previous section of this submission.

The must run status provided to renewable energy generators follows the economic principle of merit order dispatch as these generators have no variable costs. Therefore there is no requirement for a must-run incentive. Naming this proposed subsidy on renewable energy tariffs a *'must-run incentive'* is therefore misleading.

With regulatory approval, the methodology, the principle and the mechanism for the levy will come into question and given the current ambiguity in the estimation and attribution of costs could also lead to complex legal tussles increasing the regulatory uncertainty in the sector.

Given methodological issues, lack of clarity in operationalising such subsidy provision and uncertain impacts of such a dispensation in the future, we urge the Commission to not approve such a subsidy.

If the state government wants to provide a subsidy, it can operationalise this through a government order.

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