OVERCOMING POWER SHORTAGE THROUGH U.I.

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(These are personal views of the author)

INTRODUCTION

India has a huge power shortage (unmet electricity demand), which is retarding the nation’s progress. Hence, we need to work simultaneously on all fronts to increase the availability of power. The mechanism of Unscheduled Interchange (U.I.), if properly deployed, can help in bringing more power into the electricity grids, enabling the utilities to meet additional consumer load, both short-term and long-term, and significantly reduce the quantum of load-shedding.

UI has generally been known as the third component of the so-called Availability Based Tariff (ABT), which was introduced in India at the regional level in 2002-03. Many have perceived UI only as a disciplining mechanism, whereas it is actually a multi-purpose tool for tackling many of the pressing problems of system operation. This paper seeks to describe the various possible applications of UI on stand - alone basis, which can help enhance the availability of power.

A detailed explanation of ABT and UI has been provided in “ABC of ABT – a Primer on Availability Tariff” written by the same author, and released by Power Grid Corporation of India in electronic form in July 2005. It has since been widely distributed through CDs and e-mails (< 500 kB), and has been published in two parts in the July - September 2005 and January - March 2006 issues respectively of “India Power”, the quarterly journal of the Council of Power

Utilities. It can also be accessed on “www.srldc.org/downloads.htm”. A reading of the above primer would be of much help in understanding the concept of UI.

SHORT – TERM MEASURES

Some benefits of UI, in addition to those accruing due to ABT, as realized by the more progressive utilities, are as follows:

- Online optimization of generation, particularly hydro: by backing down a station when its generation can be replaced by cheaper energy and maximizing its generation when there is shortage.
- Operation of pumped-storage plants (e.g. Kadamparai and Srisailam) to their full potential, enabling higher peak demands to be met.
- Mutual support in the event of unforeseen outage of generating units, and on special occasions when one or more utilities need to meet extra demand; e.g. Pulse Polio campaign, World Cup match.
- Inter-regional exchange of power on unscheduled basis, to replace costlier energy by cheaper energy, as also to conserve hydro energy for shortage periods.

Considerable emphasis has been laid on “Open access” and wheeling of Captive generation in the Electricity Act 2003, for enhancing power supply for the end consumer. For dispute - free operationalisation of these, the UI mechanism is essential, as explained in Chapter – J of the “ABC of ABT”. In addition to the above, UI can help harness the untapped idling capacity of Captive and Co-generation, as discussed below.

HARNESSING OF CAPTIVE GENERATION

Captive power plants (CPPs) have been installed by many industries and commercial establishments all over the country, and their aggregate capacity is estimated to be about 40,000 MW. Many of these plants have been set up to serve as standby sources of power (to run critical parts / services of the respective industrial unit / commercial establishment when grid supply fails or is cut off), and are, therefore, idling for considerable lengths of time. Many other

CPPs also operate on part - load for long durations, and have spare capacity. However, since these plants have been established primarily for self - use, in most cases, there is no structured commercial arrangement in place between CPP owners and host utilities to facilitate injection of the idling / spare capacity into the grid.

All regions of the country presently suffer from serious peak-hour shortages and load-shedding / rostering has to be resorted to. With the continued growth of consumer demand, and slow pace of generating capacity augmentation, the demand - supply gap is likely to persist for many years to come. This gap could be quickly bridged, at least partly, by harnessing the existing Captive generation. Realising its importance, considerable stress has been laid on it by Govt of India in the National Electricity Policy (NEP) issued in February, 2005. Relevant part of this policy is quoted in Annexure - 1 for easy reference.

In the Electricity Act, 2003, provisions regarding Captive generation mainly relate to wheeling of power from Captive generating plants to the associated industries (in case they are not within the same premises) through the transmission system under "open access". Encouragement to Captive generation has been provided in the Act by stipulating that "surcharge shall not be leviable in case open access is provided to a person who has established a captive generating plant for carrying the electricity to the destination of his own use."

The National Electricity Policy, however, goes beyond the wheeling aspect and specifically calls for harnessing of spare CPP capacity by the licensees (including the host utilities). The last part of section 5.2.26 of NEP quoted in Annexure - 1 is of special relevance in the present context. Since most CPPs would be connecting into the intra-State grid, the appropriate Regulatory Commission, which has to exercise regulatory oversight on the commercial arrangements between captive generators and licensee would be the concerned SERC. In fact, the NEP assigns to SERCs the responsibility of tariff determination "when a licensee is the off-taker of power from captive plant"

Following aspects of Captive generation have to be kept in view while dealing with this subject.

i) Quantum of surplus power available from a CPP for feeding into the grid would most often be uncertain. Since the primary objective of the CPP installation is to support the associated industry, any increase in the industry's load and / or any decrease in CPP availability would automatically bring down the power availability for the grid (which would be the second priority here). As a consequence, the CPP may not be in a position to supply power to a utility / licensee on a committed basis. In other words, the CPPs would not be able to supply power as per a firm schedule, but only on "as-and-when-available" basis. The concerned utility / licensee would generally be unwilling to pay a remunerative tariff for such infirm power.

ii) In many cases, power supply to the industries / commercial establishments is cut off during peak-load hours (as a regular rostering measure to restrict the State's over-drawal from the regional grid), and these industries / establishments have to run their Captive generation during such hours for continued operation. What this means is that availability of Captive generation for feeding power back into the grid would be much lower during peak hours (when its support is needed the most) and comparatively higher during off-peak hours (when the utility / licensee may be able to meet its own requirement with power available from other sources).

iii) Due to their smaller size and use of costly fuel, cost of generation at CPPs would generally be comparatively higher. On the other hand, the utility / licensee would be reluctant to pay to CPPs a price higher than what it pays for bulk supply on contracted basis from regular generating stations, particularly when the CPP power is of comparatively low reliability and low peak-hour availability. Consequently the price that a utility / licensee may be prepared to pay to a CPP on a contracted basis may not even cover the variable cost of the CPP.

Due to the above, it is very likely that the SERCs, in spite of their best intentions and efforts, may not be able to arrive at a tariff (based on the conventional tariff determination principles) which is acceptable to both the parties. Under such a situation, the following approach may be adopted as a viable alternative, for harnessing the available idling / surplus capacity of the CPPs.

PROPOSED APPROACH

Instead of trying to induct the surplus CPP capacity on a contracted basis, it may be absorbed in the grid on "as-and-when-available" basis, utilising the UI mechanism. Suppose an SEB, at a given time, is overdrawing 20 MW from the regional grid. The SEB would be required to pay UI charges for 20 MW, i.e. for 5000 kWh per 15 minutes at the UI rate for that 15 minute time block. Now suppose that this particular SEB starts getting 8 MW from a CPP. If the generation and consumer load within the State remain unchanged, the SEB's over-drawal from the regional grid would come down from 20 MW to 12 MW. As a consequence, the SEB would now have to pay UI charges to the regional pool account only for 3000 kWh per 15 minutes. It can, thus, be said that 2000 kWh (per 15 minutes) received by the SEB from the CPP has replaced the 2000 kWh of UI from the regional grid. The SEB can, therefore, pay the prevailing UI rate for CPP injection and still remain financially unaffected.

The UI rate would be comparatively low during off-peak hours, and the CPP may find it unattractive to inject its surplus capacity into the grid. This would automatically solve the problem of costly power coming into the grid when it is not really required. On the other hand, during peak-load hours, UI rate would be high, and the CPP owner would be induced to maximise his injection (at a time when it is needed the most). This extra input would add to total power availability in the grid and enable a corresponding additional consumer demand to be catered. The host SEB has the option of supplying extra consumer load within the State (in which case it would have to reconcile to paying the prevailing UI rate for this incremental power), or remaining unaffected (consumer load wise and financially) as described earlier. In the later case, the extra power (from CPP) would flow to some other SEB which would pay for it at the UI rate, and cater to extra consumer demand in its area.

In this whole scheme, all actions are voluntary and nobody is under any compulsion – contractual or otherwise. The CPP gets to know the prevailing UI rate online from a local frequency meter and decides whether to inject power into the grid or not, depending of how the UI rate compares with its variable cost. The local SEB also has the option, as described above, of meeting or not meeting extra consumer load, depending on how the UI rate compares with the highest permissible power procurement rate for supply of power to these consumers. Further, there would be no complications related to contracts / agreements, scheduling and dispatch, defaults and non-compliance. The SERCs too would not have to worry about judicious determination of tariff for the concerned CPPs.

In the foregoing discussion, transmission losses in the intra-State grid have been neglected and it is assumed that the SEB operates the scheme on a totally back to back basis. However, it may be reasonable for the SEB to expect a compensation for (i) extra efforts on its part, (ii) use of its transmission system, and (iii) any incremental transmission losses. This can be easily provided by stipulating that the payment to CPPs would be at, say 95% of the regional UI rate.

FIVE CATEGORIES OF C.P.P.s

In the present context, Captive generation can be categorized as follows:

i) Stand - alone, i.e. isolated from the grid
ii) Stand-by, i.e., normally idling
iii) Running, but separately
iv) Running in synchronism
v) Located away from the associated industry, and wheeling power through the utility network.

Each of these categories has a different connotation, and would need to be treated accordingly, for effectively bringing the surplus capacity into the utilities' network.

STAND - ALONE C.P.P.s

Poor quality of grid supply (low voltage, fluctuating frequency and frequent interruptions), high tariffs (much higher than actual cost of supply), unfair impositions (peak hour restrictions and unplanned load shedding) and unresponsive attitude of SEBs have forced many industries to isolate themselves totally from the State grid and be on their own. For a reliable operation of the industry, they necessarily have to have Captive generation with a redundancy. In other words, they have available a significant amount of surplus capacity.

To harness the above surplus capacity for increasing the availability of power in the grid, a pragmatic approach is required. The concerned SEBs / successor utilities have to realize that their own urge for harnessing such capacity is more pressing than the need of the CPP owner to get reconnected. In any case, the CPP owner cannot be expected to supply power if his net recovery is less than his variable cost. The utilities have to play their part, and this would include the following, at the utility's cost:

i) Constructing / restoring the line upto the industry's premises, for adequate grid connectivity.

ii) Providing necessary switchgear, transformers, etc., and the required metering equipment in the utility's system.

iii) Allowing the industry and CPP to run in synchronism with the utility's system.

iv) Agreeing on a reasonable commercial arrangement.

v) Promptly paying for the power supplied by the CPP.

On the whole, the SEB / utility should view the industry - CPP as a friend-in-need, and not as an adversary. Instead of throwing up problems and creating road blocks, the utilities should be more pro-active. The only aspect (though of paramount importance) which the utilities need worry about is that synchronizing of the previously isolated industry - CPP does not adversely affect them financially. As explained earlier, any energy supplied by the CPP can be taken by the utility at the UI rate, either for meeting extra consumer load or for passing on to other utilities. That only leaves the problem of the CPP owning industry occasionally drawing power from the utility's network to be tackled.

Once the industry (with its CPP) is synchronized with the grid, it is possible that in case of a tripping in the CPP, the industry starts drawing power from the utility's system. How should this be commercially handled? A reasonable and pragmatic approach would be to treat this also as UI, on the criterion of reciprocity. Once the industry has invested money in setting up the CPP, it would not be fair to ask it to pay again for the fixed cost of utility's system (in the form of demand charge, connection charge, standby charge, etc.). However, to discourage the industry from unduly leaning on the utility, a 10% differential could be specified between the rates at which energy is taken from and supplied to the industry. For example, if the industry is paid at 95% of the regional UI rate for energy it supplies, it may be charged at 105% of the regional UI rate for the energy it draws. This would automatically dissuade the industry from resorting to energy drawal from the grid in situations of over-all shortage. On the other hand, the industry would get the benefit of standby power, and would readily accept the provision. The local utility also should not feel aggrieved since the support actually comes from the large interconnection (the regional grid), and it gets a wheeling charge, though not by that name.

STAND - BY C.P.P.s

Many CPPs have been set up for standby supply only. These are kept off most of the time, when grid supply is available for running the industry, and are run only when grid supply goes off, or the industry is told not to draw power, e.g. in evening hours. In these situations, the industry would be drawing power from the utility as per applicable tariff. In order not to disturb the existing commercial arrangement, and the utility's base revenue from such industries, the following is suggested.

The typical daily power drawal pattern of the industry may be determined from the past data (with CPP on standby duty), and taken as the datum schedule. The industry should then be billed for power drawal as per this schedule, as per prevailing demand charge, energy charge, etc. as the datum. Any reduction in industry's drawal due to CPP's operation (during hours it has not been running earlier) would get reflected as UI, and could be paid for by the utility at 95% of regional UI rate. Any over-drawal (compared to the datum schedule) could be billed at 105% of regional UI rate. Running of the CPP in synchronism with the grid supply would be mutually beneficial technically as well.

SEPARATELY RUNNING C.P.P.s

For reasons similar to those listed above in case of Stand - alone CPPs, many industries have split their system, with one part operating on grid supply and the other on CPP. The two parts are operated separately due to historical considerations – technical and commercial. However, in the changed scenario, it is possible, and would also be immensely beneficial, if the two parts are synchronized. The commercial arrangement for the new configuration can be same as in case of Stand-by CPPs.

C.P.P.s RUNNING IN SYNCHRONISM

There are many large industries (steel plants, etc.) which have CPPs of substantial size running in synchronism with the grid, but only at part capacity due to one-sided contracts. The utilities apply industrial tariffs, which not only have high demand, energy and other charges but also have minimum charges. These force the industries to operate the CPPs in backed down mode even when the grid has an overall shortage. For power supplied back to the grid, either there is no rate, or the rate is too low to induce the industry to increase its CPP generation for that purpose. The industry is compelled to pay a high demand charge for obtaining standby support to safeguard against an outage in CPP, without any reciprocity. The result is that many large CPPs (some even coal-fired, and having a low variable cost) are being only partially utilized.

In other cases, because the local utility refuses to pay a remunerative price, the industry is forced to consider wheeling of surplus CPP capacity to a sister unit in another State, paying various inter-State "open access" charges. This also mostly gets bogged down in procedures and formalities. All such idling CPP capacity could be beneficially harnessed if the concerned utilities and SERCs open their systems for application of UI either as described above for Stand-alone CPPs, or as described for Stand-by CPPs.

C.P.P.s LOCATED AWAY FROM ASSOCIATED INDUSTRY

These are necessarily synchronized with the grid. Besides, the utility can separately record the injection of CPP and consumption of the associated industry, unlike other cases where only the net exchange with the utility can be metered. Still, existing commercial arrangements would be similar to those applicable for other industries with co-located CPPs. Here again, there would be idling CPP capacity, which could be brought into the grid through application of UI concept.

CO-GENERATION

Many industries (e.g. sugar mills) have Co-generation plants, in which steam is drawn from the plant for industrial process, and/or an industrial by-product (e.g. bagasse) is used as fuel in the plant. Power generation, therefore, gets directly linked to the operation of the industry (unlike a CPP where power can be generated even if the industry is shut off). Availability of surplus power for injection into the grid then becomes even more unresponsive to the grid requirement. In other words, it is difficult for a Co-generation plant to be scheduled according to the utility's requirement, and the utility has to accept surplus power on as-and-when-available basis only.

Environmental and efficiency considerations dictate that the grid / utility absorb all surplus energy of such Co-generation plants. In the past, this has been taken to also mean that the local utility must pay a remunerative price for such power. It is this stipulation by regulatory agencies which is a cause of friction. There are two problems. One is that of determining the remunerative price. Each Co-generation plant is unique in many ways, and a separate exercise would be required for each. Further, the cost of power depends on apportioning of total fixed and variable costs between power and process steam, and on transfer price of fuel. Subjectivity in these is inevitable.

The above problem can be tackled by specifying a per kWh rate based on MNES recommendations, and applying it across the board. One should then reconcile to letting some industries (with comparatively low cost of generation) making more profit than would normally be allowed, and other industries (with comparatively higher cost of generation) supplying power to the grid at below the cost, or not supplying power at all.

The other problem is that when a constant paise / kWh tariff is applied, the SEB/utility is saddled with a liability to pay that rate for energy which may be acceptable during peak-load hours but may not be welcome during off peak hours (when the SEB/utility would have to correspondingly reduce its drawal from other sources of a lower variable cost, in order to accommodate the Co-generation injection).

Both these problems can be overcome by treating the entire (net) injection of Co-generation owning industry as UI, and the SEB / utility paying for it at the regional UI rate. It has already been explained earlier that this would not cause any financial loss to the SEB / utility, compared to the situation in which there is no injection. The Co-generation can be encouraged (on larger environmental considerations) by specifying that the full (100%) regional UI rate would be paid for its injection, irrespective of its geographic location in a State, and any transmission losses would be to SEB / utility account. Any drawal of energy (on net basis) by the industry could be billed by the SEB/utility at 110% of the regional UI rate. It is also possible that instead of treating the total exchange of power entirely as UI, the deviations are determined with respect to a datum schedule, and commercial arrangement is on the lines described under standby CPPs.

LONG – TERM MEASURES

The ABT and UI mechanism already in place since 2002-03 has gradually brought about a realization among the SEBs / utilities in the following respects:

i) It is necessary for them to plan in advance for catering to the future load growth in their respective areas. In the past, they could overdraw from the regional grid during peak load hours and neutralize it by under-drawal during off-peak hours, or get away by paying a comparatively low price, since their liability to pay for Central generating station supply was dependent only on net energy drawal for the whole month. Now, with 15-minute wise energy metering and a full-fledged UI accounting, they have to pay for any misdemeanour.

ii) The States have to take full responsibility for their own action and inaction, and face the consequences, as enshrined in the federal structure of India. Indian Electricity Grid Code cautions the State entities as follows:

> "6.4.5 The SLDCs / STUs shall regularly carry out the necessary exercises regarding short-term and long-term demand estimation for their respective States, to enable them to plan in advance as to how they would meet their consumers' load without overdrawing from the grid".

iii) It is expected that all States would duly take care of the above, through advance action on new generating stations - their own, IPP's and CPSUs', thereby restricting power shortage in years to come. The mechanism also provides an in-built assurance that if power to which a State is entitled, is tapped off by another State, the former would at least get a high price as compensation from the latter.

The story does not end here. The UI is also a potent tool for leveraging private power plants, both under long-term PPAs and on merchant basis, and non-conventional renewable energy sources, as explained on the following pages.

FALL BACK MECHANISM FOR P.P.A.s

Private companies are expected to come forward and set up power plants in the country in a big way, to augment the generating capacity. One major concern of such private companies is what recourse would be available to them in case the State Government-owned or private entity, which signs the Power Purchase Agreement (P.P.A.) with them is subsequently not able to fulfil its obligations. Only certain financial instruments – revolving letters of credit, escrow accounts and State / Central Government guarantees – have been talked about so far. While these can temporarily address the problem of non-payment by a P.P.A. signatory, they cannot handle the situation of recurrent default in payment of dues, or the purchaser's inability / unwillingness to continue with P.P.A. provisions.

The effective recourse in the above mentioned situation would be to enable the power plant owner to sell the power plant's output to some other entity. For example, suppose an S.E.B. has contracted to buy 100% of the capacity of a power plant (of say 500 MW) for 20 years, but finds six years down the line that it can pay for only 60% of the plant's capacity. The power plant should then be able to sell 40% of its capacity to an entity in a neighbouring State. The original PPA itself should provide for this, stipulating that the signatory SEB shall enable transmission, scheduling and energy accounting of such capacity, and shall compensate the power plant owner for any shortfall in revenue arising out of the SEB's default. The scheduling, energy accounting and UI settlement mechanism required for the above is already in place at the inter-State level, but has to be kept going by the signatory SEB within the State.

A further fall back mechanism is available through UI. In case of a default by the signatory SEB, and the power plant owner not being able to find another purchaser on workable terms, the uncovered capacity of the plant can be, and should be allowed to be injected into the State grid as UI. The SEB should be obliged to facilitate this, by arranging appropriate metering, energy accounting and regular payment of applicable UI charges to the power plant. If this is provided for in the P.P.A., and the State / Central Governments undertake to enforce UI payment to the power plant owner from the State's UI pool account, there may not be any further need for escrow accounts and State / Central Government guarantees. Transmission system would generally not be a constraint, as it would already have been designed for absorbing the full output of the power plant.

MERCHANT POWER PLANTS

Enterprising private companies can even set up power plants without bothering to tie-up PPAs for full plant capacity at the financial closure stage. Depending on the prevailing situation, PPAs may subsequently be finalized, but not necessarily covering the entire plant capacity or expected life. The uncovered plant capacity from time to time would then be available for short-term contracting, as per market conditions. It would only have to be ensured that the transmission system, particularly in the plant's vicinity, has the requisite capacity to absorb and disperse the entire output of the plant.

The uncovered / surplus plant capacity at any time can also be accepted in the State grid at the prevailing UI rate, which is the spot price. There need be no apprehension about such merchant plant making disproportionate profits: both fixed and variable costs have to be recovered from the prevailing UI rate, which is capped by a regulator-specified ceiling rate and can never spike. On the other hand, the country would continue to have peak-hour shortages for many years to come, and UI rates would continue to be sufficiently higher than the variable cost, to generate adequate revenue for fixed cost recovery.

WIND POWER

As per a document of the Indian Wind Power Association, over 3000 MW of wind power capacity is already installed in India, and the gross wind energy potential in the country is estimated at 45000 MW. Wind power can therefore significantly contribute in meeting India's growing energy demand.

The wind power, when compared to other sources of electrical energy, has certain peculiarities. Its availability is entirely in the hands of the nature, and it has a daily pattern which generally differs from the consumer load pattern. Its variable cost is zero, but its installation cost is high, about Rs.4.5 crore per MW. With a typical PLF of around 24%, the average cost would be about Rs.3.50 per kWh (Rs.2.90 per kWh on levelized basis), ex-wind farm. And, it is difficult to be supplied under a power purchase agreement since it is not conducive to day-ahead scheduling due to unpredictable availability.

All the above mentioned aspects have to be taken into consideration for harnessing this "green" power. Because of its zero variable cost, all available capacity of wind generation should be brought into the grid, day and night. The pricing of wind power is thus a difficult issue: while it is necessary for the plant owner to recover the full cost of generation, the price has to be comparable to what an SEB would pay for replacement energy from another source, at any given time.

The UI approach provides a ready answer to this problem, from the SEB's angle at least, as explained above in detail for Captive power plants. To reiterate, the wind generation can be priced at the regional UI rate from time to time. As the rate would be low during off-peak hours, the SEB would have no reason for complaining about unsolicited energy being dumped into its system, or feel compelled to absorb the wind energy in a surplus situation. On the other hand, the high rate during peak-load hours should also not deter the SEB from accepting this energy, as it would pay for it the same rate as for replacement energy (UI) from the regional grid.

In case the SEB asks for a compensation for (i) extra efforts on its part, (ii) use of its transmission system, and (iii) any incremental transmission losses, it can be told by the SERC to treat these as its contribution for "green" power, and pay full (100%) regional UI rate for energy received from the wind farm.

The only question which would then remain unanswered is whether the wind farm owner would get adequate revenue through the above UI-based pricing scheme to cover the generation cost. For this, an exercise can be carried out in advance using the expected daily generation profile and the daily UI price profile. In case the expected revenue is inadequate, there would be a case for grant of a subsidy by the Ministry of Non-Conventional Energy Sources to bridge the gap and ensure financial viability of the concerned wind generation plant. Alternatively, the project may be proposed for carbon credit (CDM).

Let us consider an example. Suppose a 4 MW wind farm can be set up at a certain location at a capital cost of Rs.18.0 crore (Rs.4.5 crore per MW). Suppose the debt / equity ratio is 75:25, the interest rate is 10% and pre-tax ROE is 16%. Assuming a plant life of 20 years, the levelised annual cost would be as follows:

i)	Interest on loan =	1800 * 0.75 * 0.10 =		Rs.135.0 lakh
ii)	Return on equity =	1800 * 0.25* 0.16 =		Rs. 72.0 lakh
iii)	O & M @ 15% =	1800 * 0.015 =		Rs. 27.0 lakh
iv)	Amortization of loan part =	23.56 }		
v)	Amortization of equity part =	3.90 }		Rs. 27.46 lakh
			Total	Rs.261.46 lakh

Now suppose the wind farm is expected to have a PLF of 22%.
Then, annual generation = 4000 * 0.22 * 365 * 24 = 77.09 * 10^5 kWh.

And the levelised cost of generation = 261.46 / 77.09 = Rs.3.39 per kWh.

Suppose a study of the daily wind pattern over the year, and the pattern of UI rate based on past frequency pattern reveals that the weighted average UI rate which the farm's output would get is Rs.2.75 per kWh. It would mean that if the wind farm gets paid only through the UI mechanism, it would have a deficit of 64 paise / kWh. It can therefore apply to the Ministry of Non-Conventional Energy Sources for a subsidy of 64 paise per kWh for the initial years of operation. While agreeing to it, the MNES may stipulate that the above subsidy would be tapered down and subsequently withdrawn as the CERC raises the UI rate (consequent to rise in diesel generation cost to which ceiling rate of UI is linked) and the deficit accordingly goes down.

Also note that in case the interest rate was 8% instead of the earlier assumption of 10%, and expected PLF was 24% in place of 22%, the levelized cost of generation would only be Rs.2.86 per kWh, and subsidy requirement would be reduced to just 11 paise per kWh.

In the above approach, there would be no need to look into the cost of generation of each installation separately (for tariff fixation), and all similar supplies of energy at a particular time shall be paid at the same rate, e.g. the regional UI rate prevailing at that time. The biggest advantage of this approach is that all available wind energy can be assimilated in the grid without any reservation, as the SEB suffers no financial loss.

Other Non-conventional / Renewable energy sources (Mini - hydel, Solar, Bio-mass, etc.) are no different from Wind generation, in respect of the commercial and operational aspects discussed above. The same approach can, therefore, be applied to them as well.

METERING REQUIREMENT

For implementation of the proposed UI approach, it is essential to install the so called ABT meters on the interconnecting link between the SEB/utility and the concerned party, i.e., the CPP / Co-generation owning industry, Wind farm, etc. Proven meters of a standardized specification are readily available indigenously, at a reasonable price.

These meters have to be electronically read once a week, and the down-loaded data has to be transferred through a local PC to the concerned SLDC, for centralized weekly computation. The SLDC has to operate the State UI pool account (similar to regional UI pool accounts operated by RLDCs), and ensure timely collection/payment of UI charges to all concerned. These may not be too difficult to organize, once all parties realize that it is a win - win situation for all. In due course, this entire operation can even be decentralized to DISCOM level.

REACTIVE POWER

U.I. covers only the active energy (kWh). Reactive energy exchange also requires monitoring and pricing. The parties connecting into the grid have to be induced to supply reactive energy when the voltage at the interconnecting point is low, and to draw reactive energy when the voltage is high. The reactive energy charging scheme applied at regional level (and specified in the Indian Electricity Grid Code) is eminently suitable for this, and may be directly applied for all CPPs, Co-generation plants, wind farms, etc.

A PITFALL

As of now, there is no compulsion for timely payment of UI, except for the following stipulations in the Indian Electricity Grid Code:

"Regional energy accounts and the statement of UI charges shall be prepared by the RLDC on a weekly basis and these shall be issued to all constituents by Saturday for the seven-day period ending on the previous Sunday mid-night. Payment of UI charges shall have a high priority and the concerned constituents shall pay the indicated amounts within 10 (ten) days of the statement issue into a regional UI pool account operated by the RLDC. The agencies who have to receive the money on account of UI charges would then be paid out from the regional UI pool account, within three (3) working days."

"If payments against the above UI and VAr charges are delayed by more than two days, i.e. beyond twelve (12) days from statement issue, the defaulting constituent shall have to pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the constituents who had to receive the amount, payment of which got delayed. Persistent payment defaults, if any, shall be reported by the RLDC to the Member Secretary, RPC, for initiating remedial action."

Some States have continually defaulted in payment of UI, in spite of being cautioned by CERC periodically. This is a serious matter, and jeopardizes the whole scheme of ABT and UI, notwithstanding that as high an amount as Rupees 12,000 crore has been paid into and distributed from the regional UI pool accounts operated by the RLDCs over the past three years, without any dispute, and without even a Letter of Credit.

The entire discussion in this paper is premised on timely payment of UI charges by the SEBs / successor utilities to the suppliers of UI energy. Considering the present financial status of State utilities, and the fact that State Governments have to subsidize their operations even otherwise, it would only be logical to ask the respective State Government to guarantee timely UI payment. This is a pre-requisite and is most crucial for the success of the endeavour.

U.I. – DIFFERENT PERSPECTIVES

The Indian version of Availability Tariff comprises of three components: Capacity charge, Energy charge and UI charge. The conventional Availability Tariff (adopted in other countries) has only the first two components, since deviations from schedules are minimal, and have to be neutralized in kind. The third component is necessary and crucial for India because our utilities deviate from schedules perpetually, and are unable to neutralize the deviations in kind, for various reasons. Still, if a generating station delivers power strictly according to the given schedule, it would not have any UI charge, and it would effectively have only a two-part tariff, as is the case in other countries. Looked at from this angle, it can be said that UI is not a component of generation tariff, but a mechanism for handling and settlement of deviations from schedules, uniformly applied to all entities - both suppliers (generators) and recipients (SEBs).

Next, suppose an SEB has a schedule of 1000 MW import from the regional grid at a particular time, but it is actually importing 1120 MW. It would have to pay for the 1000 MW as per agreements which cover this scheduled supply, and for the 120 MW of over-drawal, it will have to pay as per the UI rate prevailing at that time. This is the settlement part mentioned in the previous paragraph. It is automatic, objective, precise and dispute-free. There is another aspect as well. If the SEB's import now increases by 25 MW, the SEB would have to additionally pay for this 25 MW at the UI rate. If, on the other hand, the SEB's import reduces by 25 MW, its payment liability would reduce by the UI rate applied on each unit of energy drawal reduction. Thus, the short-term marginal price, as actually seen by the SEB, is the regional UI rate at that time.

The situation would be the same even if the SEB had been under-drawing to start with. For example, if the SEB had actually been importing 900 MW against a schedule of 1000 MW, it would have to pay for the 1000 MW as per agreements which cover this scheduled supply, and it would receive payment for energy (corresponding to 100 MW) not drawn at the UI rate. With this position as the datum, an increase in import from 900 to 920 MW would mean net additional payment by the SEB for 20 MW at the UI rate.

The UI rate being same, at a given time, for all the SEBs / utilities, it is not only the short-term marginal price seen by the SEBs individually, but also effectively becomes the system marginal price. It is also equivalent to pool price, spot price and balancing market, the terms used in different countries. All players can see the same, on-line, through local frequency meters. UI is thus a very powerful tool.

STATUTORY SUPPORT FOR A.B.T. AND U.I.

The Electricity Act, 2003 lays considerable stress on "secure" and "economic" operation of the regional and State grids. Frequency of regional grids has dramatically improved after introduction of ABT, resulting in remarkable improvement in system security. Grid collapses are now a thing of the past. This is primarily because of the way in which UI discourages undesirable over-drawal and over-generation. The economy in system operation has come through the region-wide merit-order operation of generating stations which has been induced through separation of fixed and variable costs in ABT. It can, therefore, be rightly claimed that the ABT and UI have statutory sanction.

There is another angle. If one reads section 28(3) of the Act closely, it may appear that there is a contradiction. As per sub-section (a), the RLDCs have to schedule and dispatch the electricity "in accordance with the contracts entered into with the licensees or the generating companies operating in the region", whereas as per sub-section (e), the RLDCs have to ensure economic operation of the regional grid (which means scheduling the generation according to merit-order). What should an RLDC do if contractual arrangements require a generating station of high variable cost not to back down ? A simple solution to this dilemma is provided by UI under the ABT framework. The generating station should be scheduled by the RLDC in accordance with its contract or PPA, and then allowed to deviate from schedule on its own, to ensure economic operation of the regional grid. (Please see Chapter-E of "ABC of ABT" for a detailed explanation).

The following is stated in section 5.7.1(b) of the National Electricity Policy issued by the Ministry of Power, Govt. of India in February 2005.

"The ABT regime introduced by CERC at the national level has had a positive impact. It has also enabled a credible settlement mechanism for intra-day power transfers from licensees with surpluses to licensees experiencing deficits. SERCs are advised to introduce the ABT regime at the State level within one year."

As for utilization of UI for harnessing Captive generation, the following statement appears in section 6.3 of the Tariff Policy issued by the Ministry of Power on 6th January 2006 :

"Alternatively, a frequency based real-time mechanism can be used and the captive generators can be allowed to inject into the grid under the ABT mechanism."

As such, there is already a mandate to strengthen and take forward the framework of ABT and UI, and derive benefits of its potential to the fullest. However, continued success of ABT in India depends on timely payment of UI charges. It is necessary that a mechanism be placed in position to compel all overdrawing utilities to promptly pay the UI charges, to ensure that the incentives and disincentives provided by this mechanism continue to be effective. It is in this context that the Govt. of India may consider backing up the State Government undertaking to enforce UI payment (as mentioned earlier) by undertaking to resort to Central Plan Appropriation, in case of a continuing default.

ANNEXURE – 1

EXTRACT FROM “NATIONAL ELECTRICITY POLICY” ISSUED BY MINISTRY OF POWER, GOVT. OF INDIA ON 12.02.2005

“Captive Generation

5.2.24 The liberal provision in the Electricity Act, 2003 with respect to setting up of captive power plant has been made with a view to not only securing reliable, quality and cost effective power but also to facilitate creation of employment opportunities through speedy and efficient growth of industry.

5.2.25 The provision relating to captive power plants to be set up by group of consumers is primarily aimed at enabling small and medium industries or other consumers that may not individually be in a position to set up plant of optimal size in a cost effective manner. It needs to be noted that efficient expansion of small and medium industries across the country would lead to creation of enormous employment opportunities.

5.2.26 A large number of captive and standby generating stations in India have surplus capacity that could be supplied to the grid continuously or during certain time periods. These plants offer a sizeable and potentially competitive capacity that could be harnessed for meeting demand for power. Under the Act, captive generators have access to licensees and would get access to consumers who are allowed open access. Grid inter-connections for captive generators shall be facilitated as per section 30 of the Act. This should be done on priority basis to enable captive generation to become available as distributed generation along the grid. Towards this end, non-conventional energy sources including co-generation could also play a role. Appropriate commercial arrangements would need to be instituted between licensees and the captive generators for harnessing of spare capacity energy from captive power plants. The appropriate Regulatory Commission shall exercise regulatory oversight on such commercial arrangements between captive generators and licensees and determine tariffs when a licensee is the off-taker of power from captive plant."

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