Cost-Effectiveness of Emission Control at Fossil-Fuel Units for Different Cumulative Load Patterns

S. Roy, Member, IEEE
Department of Electrical Engineering
Indian Institute of Technology
Delhi, INDIA.

Abstract- This paper describes a method to recommend allocation of generating units, with a view to achieve cost-effective control of particulate and gaseous emissions over a specific energy scenario. Definition of relative cost and relative emission, with respect to corresponding base-case values, allows one to develop a model that describes cost and emission aspects of the chosen scenario. Optimisation of this model, by any appropriate linear-programming software, yields the allocation levels to be recommended.

The emphasis of this paper is on the way in which results of the said optimisation model reflect the effect of demand patterns on the allocation levels. Depending on the demands, required generation levels from each individual unit may differ. This affects the overall generation cost, and simultaneously the emissions from the thermal units, both relative to respective base values. Since the optimisation algorithm attempts to reduce both the relative quantities, its results always reflect the changing generation vs. emission tradeoff for utilities vis-a-vis different demand patterns.

keywords: Emission control, economic evaluation, demand patterns.

I. INTRODUCTION

It has been generally recognised for some time [1], that given an energy scenario inclusive of installed emission-control technologies at fossil-fuel units, significant reduction may be achieved in levels of particulate and gaseous emissions at system-operation level. A considerable degree of investigation has been made into the possibility of minimising emissions, vis-a-vis increase in operational costs thereby incurred [1-3]. An obvious question that emerges from all such approaches to the problem, concerns the extent to which reduction in emissions may be economical for the participating utilities. The answer to this question can be highly subjective because of two reasons. Firstly, while the emission/cost tradeoff is itself rather well accepted, it is difficult to compare the two factors mutually owing to incompatible units of measure. Secondly, the said tradeoff will depend significantly on the energy demand of each participating utility of the scenario, together with certain associated cost factors such as transmission and wheeling costs, startup costs of fossil-fuel units, and availability of each unit in the scenario.

Some approaches to overcome the first bottleneck are described in [1]. In [4] a new approach to the optimisation problem has been introduced, that employs a novel method to make the reduction in emissions and corresponding increase in overall cost mutually comparable. Because of this important feature of the method, the effect of demand patterns on the cost/emission tradeoff and the allocation schedule of individual units becomes obvious and easy to follow. The optimal results can therefore be traced down to utility demands, as well as generation and emission from fossil-fuel units, for any type of demand pattern over the scenario. The objective of this paper is study the last mentioned feature of the approach, and to establish interpretations of the optimal results in practical terms such as unit startup, Total Emission Levels of utilities, and peak- and base-energy demands.

For illustration purposes, the algorithm has been executed for different demand schedules of a fifteen utility scenario, that has been developed from a certain section of the existing power network of India. The discussions included in this paper refer to two time-spans of three months each, namely: Q1- April, May, June; and Q2- July, August, September. These two quarters are found to differ significantly in load and emission patterns, and are adequate to explain the dependence of the emission control algorithm on the same. Within each individual
quarter, the 182 hours of maximum MW loading constitute the "peak" period, the 622 hours of minimum MW loading are defined as the "base" period, and the remaining 1304 hours of MW load are included in the "intermediate" period.

II. RELATIVE COST / RELATIVE EMISSION OPTIMISATION ALGORITHM

Given the installed emission control technologies at fossil-fuel units in an energy scenario, under what conditions may one consider a reduction in emissions to be cost-effective? At the outset, considering the situation when no fossil-fuel unit is controlled for emission, the optimal total generation cost for the scenario assumes a certain minimal value, that may be defined as the base-case generation cost. Corresponding to this situation, the fossil-fuel units of the scenario produce an amount of emission that is in no way restricted by the emission-control technologies. This quantity of emission will be henceforth referred to as base-case total emission. It is important to realise, that the participating utilities would attempt to reduce the total emission from its base-case value, and would correspondingly expect an increase in the total cost over the base-case value of the latter. The optimisation algorithm is therefore formulated as a tradeoff between a relative cost (the total generation cost normalised by the base-case generation cost) and a relative emission (the total emission normalised by base-case total emission). The analytical description of the algorithm is summarised below.

The following variables are defined at the outset:

\(a_i\): Total generated energy from the \(i\)-th unit. For \(k\) periods of operation (base: 1, intermediate: 2, peak: 3):

\[
Ci(\{x\}) = \sum_{i=1}^{3} \sum_{r=1}^{M} \text{Ci} (r, i, k)
\]

\(Ct(\{x\})\): The cost of generating the total energy supplied by the \(r\)-th unit. If the cost of generating one kWhr is given as \(c_r\), then \(Ct(\{x\}) = \sum_{r=1}^{M} \text{Ci} (r, i, k)
\]

\(UC_{s, k}^r\): The cost of energy deficit in the \(s\)-th utility in the \(k\)-th period. If the cost per kWhr of generation in the \(k\)-th period is given by \(sc^r\), then \(SC^r = \sum_{k=1}^{M} UC_{s, k}^r\)

\(p_r\) : Weightage according to regulatory priority for the \(r\)-th emission (Ash: 1, fly-ash: 2, SO\(_x\): 3, NO\(_x\): 4, CO\(_2\): 5), assigned values by mutual agreement of the central authority (to be discussed subsequently) and the utilities. These are as stated in Table I [5].

\(e_{r, y}\): The emission coefficient (kg/kWhr) for the \(r\)-th emission at the \(ir\)-th generating unit.

\(S\): Total number of utilities in the scenario.

\(M_i\): Total number of units in the scenario.

\(M_e\): Total number of emissive units within the scenario.

\(iV\): Number of units optimised for emission.

It should be understood that the usage of the energy deficit \(UE_{s, k}^r\) allows for the fact that, in many utilities of developing regions, rapid growth of energy demand may occasionally lead to a situation where demand exceeds supply temporarily. The cost per kWhr of deficit energy \(kgt\) is usually assigned very high values, so that the tendency of the optimisation process is to reduce the energy deficits as far as possible. Within the formulation of the algorithm, negative energy deficits represent situations where energy available exceeds demand (and can be exported from the concerned utility), and changes in energy deficits are possible as emission is increasingly controlled at the fossil-fuel units.

### Table I

<table>
<thead>
<tr>
<th>Emission</th>
<th>Priority</th>
<th>kg/kWhr</th>
<th>No. of emissive units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ash</td>
<td>0.25</td>
<td>0.04-1.31</td>
<td>70</td>
</tr>
<tr>
<td>Fly-ash</td>
<td>0.30</td>
<td>0.01-0.05</td>
<td>34</td>
</tr>
<tr>
<td>SO(_x)</td>
<td>0.25</td>
<td>0.00111-0.013399</td>
<td>72</td>
</tr>
<tr>
<td>NO(_x)</td>
<td>0.10</td>
<td>0.00129-0.01206</td>
<td>80</td>
</tr>
<tr>
<td>CO(_2)</td>
<td>0.00</td>
<td>0.48-2.59</td>
<td>80</td>
</tr>
</tbody>
</table>

For the base-case, the overall generation cost-function, defined as:

\[
J_1^0 = \sum_{i=1}^{M} C_0^0(x_i) + \sum_{k=1}^{M} \left( \sum_{i=1}^{3} \sum_{r=1}^{M} UC_{s, k}^r \right)
\]

is minimised for the whole scenario as a linear programming problem [6]. The optimal value of the objective function \(J_1^0\) is taken to be the base-case generation cost. The base-case total emission is then computed as:

\[
J_2^0 = \sum_{i=1}^{M} p_r^2 e_{r, 1} x_i
\]

The relative cost-emission penalty function that is to be minimised for a particular number of units (IV) under emission control (0 ≤ IV ≤ Me), is now defined as:

\[
J_2^1 = \sum_{i=1}^{M} p_r^2 e_{r, 1} x_i
\]
\[ j_s = j_L + J_{\text{em}} \tag{3} \]

where \( J_{\text{em}} \) is a generation cost term defined as:

\[ J_{\text{em}} = \sum_{j=1}^{M} C_{N,j}(x_j) + \sum_{k=1}^{3} \left( \sum_{i=1}^{M} SC_{N,k,i}(x_{k,i} - x_{k-1,i}) \right) \]

and \( J_{\text{em}} \) is the total emission term defined as:

\[ J_{\text{em}} = \sum_{i=1}^{N} E_{N,i}(x_i) = \sum_{k=1}^{3} \left( \sum_{i=1}^{3} UC_{N,k,i} \right) \tag{4} \]

The base-case problem defined by eqn.(1), and the subsequent penalty minimisation problem defined by eqns.(2-5), are to be solved subject to certain constraints. These are described in detail in [4], and also stated briefly in Appendix 1.

III. LOAD AND EMISSION PATTERNS

The scenario studied in this paper consists of fifteen utilities, A through O, that are interconnected by 110kV, 220kV, and 440kV transmission lines [5]. Each utility has a demand schedule in each quarter, as well as a certain number of fossil-fuel and hydro units, whose capacities and availability factors are known. The utilities are free to mutually trade energy over the available transmission lines [4]. The scenario has a central authority as an additional participant, that may be viewed as a collective organisation of all the utilities. The central authority owns large generating units of its own, from which utilities are free to purchase energy to meet their demands. It also decides certain generally applicable regulations, such as setting the minimum share of each utility in the energy generated by the centrally owned units, and setting the emission priorities (\( p_r \)). It is obvious that that the central authority essentially acts as a "utility without demand"; and in scenarios where such organisations do not exist, the algorithm described above may be applied by simply setting the number of centrally owned units to zero [4].

The variation of load levels for individual utilities is best studied in terms of "peak-to-base" and "intermediate-to-base" ratios, when these are plotted against the respective base load levels. The said plots for the quarters Q1 and Q2 are illustrated in Figs.1a and 1b.

In order to similarly study the emission patterns, the Total Emission Level (in the \( c \)-th period) for an utility may be defined as the anticipated contribution (in kg/hr) of total prioritised emission due to the utility, without any consideration of inter-utility energy transfer. Thus \( TEL^*_a \) for the \( a \)-th utility can be defined as:

\[ TEL^*_a = \frac{EC_a}{GC_a}D_{olor} \tag{6} \]

where:

\[ EC_a = \sum_{i=1}^{\text{Nr}} \text{XP}_i & \text{fr}_{i,a} + 1 + \sum_{i=1}^{\text{Nr}} \text{Pr}_{i,a} \]

Fig.1a Demand level ratios for Q1. (solid line: peak/base; dashed line: intermediate/base)

Fig.1b Demand level ratios for Q2. (solid line: peak/base; dashed line: intermediate/base)
IV. COMPARISON OF PREDICTED RESULTS FOR Q1 AND Q2

which may be referred to as the emission contribution level and generation contribution level, respectively, of the \( s \)-th utility; while \( D_s \) is the demand of the \( s \)-th utility in the \( fc \)-th period. Further, \( M_s \) and \( M^* \) are the total number of generators owned by the \( s \)-th utility and the central authority respectively; \( f_{ir} \) and \( a^* \) are respectively the installed capacity and availability factor of the \( t \)-th generating unit; and \( y_c \) is a coefficient that determines the minimum fraction of the energy generated by the \( i \)-th centrally owned unit, that must be utilised by the \( s \)-th utility (refer Appendix 1).

Figs. 2a and 2b show plots of the intermediate-to-base and peak-to-base ratios against the base level of TEL, for Q1 and Q2 respectively.

A comparison of the demand level ratio patterns and emission level ratio patterns for the two quarters can now be carried out on the basis of the above figures. It is observed that of all the utilities constituting the scenario, A, D, E, G, and K are expected to have the most significant influence on the overall generation cost by the demand ratios; while E, F, I, and J are significant due to their base-level demands. Similarly by emission considerations, A, B, E, and F affect the optimal performance by the TEL ratios; while A, B, E, and J influence the same by the base-level TEL’s.

In view of the utility demand patterns in Q1 and Q2, one may now study the cost and emission results predicted by the algorithm on a comparative basis. In order to do so, it is helpful to obtain a tabulated chart of the number of units of each utility that are brought under emission control for increasing values of \( N \). Table II provides this information for quarters Q1 and Q2, respectively.

Figs. 3 and 4 illustrate the variation of relative cost, and relative emission for Q1 and Q2. The variations are plotted against different values of \( N \), the number of generating units brought under emission control. These results are now discussed vis-a-vis Table II.

Emission control at 10 units: The base demand for utility I is 2.2GW in Q1 as compared to 1.8GW in Q2. This makes it necessary for I to generate more in Q1, thereby resulting in a much higher level of base TEL (2300 kg/hr) in the same quarter, as compared to 2000 kg/hr in Q2. A large unit of I therefore figures in the list of the ten most emissive units of the scenario in Q1, as against an unit of G in Q2. Individually however, the generating units of I are much less emissive (and hence more expensive to generate from), than those of G. Because of this, control of emissions at ten units in Q1 leads to a lower overall cost than that obtained by a similar control in Q2. Correspondingly, the improvement in emission is marginally lower in Q1 than in Q2.

Emission control at 20 units: The very large base demand of utility K in Q1 (about 3.4 GW), as compared to that in Q2 (about 3.0 GW); accounts for the fact that the base TEL of K has a value of 2900 kg/hr in Q1, as compared to 2600 kg/hr in Q2. A major emissive unit of K therefore qualifies for emission control in Q1, as
TABLE II
NUMBER OF UNITS IN EACH UTILITY
BROUGHT UNDER EMISSION CONTROL FOR Q1/Q2.

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
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<tr>
<td>10</td>
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<td>3/3</td>
<td>3/3</td>
<td>3/3</td>
<td>4/4</td>
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<td>20</td>
<td>2/2</td>
<td>3/3</td>
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A: (Hydro units only)

<table>
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<tr>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
<th>J</th>
<th>K</th>
<th>L</th>
<th>M</th>
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<tr>
<td>1/0</td>
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<td>2/2</td>
<td>2/0</td>
<td>2/2</td>
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C and D evidently affect the optimisation process only by their respective demand schedules, while the others become effective through both demand and TEL levels.

The demand features that introduce significant differences between Q1 and Q2 are (i): peak/base ratios of A and F (A higher for Q1, F higher for Q2); (ii): base level, peak/base ratio, and intermediate/base ratio for E, all three being higher for Q1; and (iii): a very high peak/base ratio for C in Q1. Likewise the emission features of importance are (a): a high peak/base TEL for Q1; (b): high peak/base ratio for B in Q1, but a higher base TEL for B in Q2; and (c): a very high peak/base ratio for E in Q1, together with a high base TEL in Q2.

Emission control at 30 units: Units that belong to A, B, E, and F, are sufficiently emissive for them to figure in the ranking list, whenever control is to be imposed on thirty or more units. (The single exception to this trend is G, which has sufficiently high generation for some of its more emissive units to occur in the lists for $N = 10, 20$).

against a centrally owned unit of L in Q2. With almost negligible increase in cost, this introduces some improvement of emissions in the latter. However the large demand for energy in K forces excessive generation (and hence emission) for K in Q1, so that there is actually an increase in overall emissions.

Emission control at 50 units: In this case, the units that are brought under emission control are the same for Q1 and Q2, so that the generation in Q1 can now shift to the more emissive generators in order to handle the greater demand for energy. This clearly permits the overall cost to fall once more, with a corresponding rise in emission level.

Emission control at 70 units: For emission control at fifty or higher number of generators, the ranking of emissive units is dominated by the units of I and K in Q1, and those of B in Q2. It is noted that I and K have base demand levels of 2.2 GW and 3.4 GW respectively in Q1, as against 1.8 and 3.0 GW in Q2. Correspondingly, I and K have base TEL levels of 2300 and 2900 kg/hr in Q1, as against 2600 and 2600 kg/hr in Q2.

As against this, B has a base demand of about 0.75 GW in Q1, and 1.0 GW in Q2. Corresponding base TEL

![Fig.3 Variation of total cost in Q1 (solid line) and Q2 (dashed line).](image1)

![Fig.4 Variation of emission in Q1 (solid line) and Q2 (dashed line).](image2)
levels are 1250 kg/hr in Q1, and 1600 kg/hr in Q2 respectively. However since in general the base TEL takes low values for B, the influence that this has on the cost-emission tradeoff in Q1 is moderate as compared to the effect that I and K have on Q2. Because of this the net rise in relative cost for $N = 50$ is substantially greater in Q1 than in Q2, with a corresponding improvement in emission.

**Emission control at 60 units:** At this level one observes the entry of a few units of K, as well as more units of I, that actually have low generation costs. The result is a significant improvement of cost in Q1, with a corresponding rise in prioritised emission. A similar trend is observed in Q2, though in this case the same is less severe, being influenced largely by the excess demand in B.

**Emission control at 10 and 80 units:** For very large clusters of thermal power units, virtually all the units introduced have very low capacity. Therefore units with low generation cost, as well as low emissions (mostly from I, K, and M), are seen more frequently. Since I and K have high demand levels in Q1 (and hence base TEL's as well), the net effect of controlling emission from their units is to increase the overall generation cost of Q1, simultaneously bringing down the emission levels significantly. With the inclusion of the last ten emissive units, the cost is moderated at the expense of emission, and the reversal of trend is noticed.

The effect of $N = 70$, 80 on Q2 cost/emission is the reverse of Q1, since Q2 is more influenced by the low levels of demand in utility B. Also because of the same reason, the changes in cost vis-a-vis emission are less severe.

**V. CONCLUSIONS**

The economic viability of imposing emission control on a thermal power generating unit is indirectly dependent on many factors, including (a) cost of generation at neighboring units (particularly non-emissive units in the neighborhood), (b) variation in peak, intermediate and base loads in the concerned and neighboring utilities, and (c) a very complicated dependence of transmission losses on generation/loads. This paper has attempted to highlight the effect of some of the above mentioned factors on the cost-effectiveness of emission control at thermal units.

**VI. REFERENCES**


**APPENDIX 1**

**Generation constraints:**

1. The generation by each generating unit, in any operating period, is limited by the available generating capacity of the unit for the period.

2. For each centrally owned generating unit, the total energy generated in a particular period limits the total energy that all utilities may obtain from it.

3. For each generating unit, the generation level in the peak period must be greater than or equal to the corresponding level in the intermediate period. A similar relation also holds between the generation levels in the intermediate and the base periods.

**Energy transaction constraints:**

4. The energy purchased by an utility from a particular centrally owned generating unit, in a particular period of operation, must exceed a minimum fraction of the total energy generated by the unit in that period; the said fraction being specified by the central authority.

5. The total energy deficit for each utility, in any period of operation, is limited by a limit stipulated by the central authority.

6. The energy traded between utilities (in any period) over individual transmission lines is limited by the capacity of the particular line.

**Demand-supply constraints:**

7. This is a set of constraints that equates for each individual utility, the sum of generation, shares of central generation, energy imports (negative for exports), and energy deficit, to be greater than or equal to the total demand for the utility in the particular operating period.

S. Roy (M' 1989) did his B. Engg. (Electrical) from the University of Roorkee, Roorkee, India, in 1985; his M. Engg. (Electrical) from the Indian Institute of Science, Bangalore, India, in 1987; and his Ph. D. from the University of Calgary, Calgary, Canada, in 1991. He currently holds the position of an Assistant Professor at the Indian Institute of Technology, Delhi, India. His areas of research interest include energy systems modeling and optimisation.
DISCUSSION

Subir Sen, Aijaz Ahmad and D.P. Kothari (Centre for Energy Studies, Indian Institute of Technology, New Delhi, India): The author is to be commended for his valuable work on emission control for different cumulative load patterns at fossil-fuel units. This subject is timely since there is a recognised need for controlling emissions from fossil-fuel units in large power systems like India. However, we would like to seek the author’s clarification on the following points:

1. Author has classified the loading within each individual quarter (3 months) in three periods. 182 hrs of loading as 'peak' period, 622 hrs as 'base' period and remaining 1304 hrs as 'intermediate' period which makes total 2108 hrs. Whereas for three months total no of hrs would be 2160. Please clarify.

2. In Table-I, the priority of CO\(_2\) emission should be 0.1 instead of 0.0 as shown in the paper because it is logical that \(E_{p_1} = 1.0\) otherwise the overall analysis would yield illogical results.

3. In section-III, author has mentioned that considered utilities (in India) are interconnected by HOKV, 220kV and 440kV transmission lines. However, in India, at present the highest voltage transmission is at 400kV level. Further, the utilities in India are also interconnected by 132kV links.

4. It would have been better if the authors would have presented the unit characteristics (cost & emission) of each utility in an appendix. This would enable better understanding of the analysis made in the paper for emission control at different number of units. For example, emission control at 30 units, it is apparent from analysis that units in utility G are less emissive. Whereas from Table-II, it seems that units in utility J and K are also less emissive but there is no idea about their cost w.r.t units in utility G. It would have been welcome if the author furnishes those units characteristics which would help further researchers in this area.

5. Has the author considered the inter-utility transmission capacity limits (which is important from steady-state as well as dynamic stability point of view)? Otherwise the results will be different and the emission control may be achieved at the price of higher fuel cost.

6. Mixing of fuels with different pollution rates and the capability of burning different fuels together in multi-fuel thermal units must be exploited in order to meet environmental constraints as well as fuel availability limitations. We would like to know whether this aspect has been taken into account or not.

7. It would have been better if other six months of the year October to March could also have been included in the discussion. That way one could compare the emission control achieved in summer with that of winter.

Finally, we would appreciate the author’s comments on the above observations and congratulate him on his excellent work and look forward to his further investigations in the field.

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S. Roy: The author would like to thank the discussers for their interest in the paper. The answers to the clarifications sought by them are as follows:

The case study presented in the paper uses three-month periods, in each of which the necessary data has been compiled for 2108 hours. The remaining fifty two hours have been left out after every three-month period for better and more distinct definition of the quarters, (such as Q1 and Q2). The algorithm described can be applied equally well to sets of data where the periods are defined differently.

The discussers have somehow failed to interpret the priority levels mentioned in Table I correctly. The author would like to emphasise that the value \(p_r\) has absolutely no resemblance to probability of any kind. They therefore need not sum up to unity, as interpreted incorrectly by the discussors. The priority levels are weighting factors that reflect the relative importance of each emission, and are decided by policy for the scenario. In the present case, the fact that \(p_r = 0.0\) for carbon dioxide is not "illogical", as the discussers seem to think. It simply indicates that emission of carbon dioxide is not given any importance as compared to the other elements of Table I. The weight could be assigned on the basis of economic as well as environmental considerations. For details on this, the discussers are requested to refer to [4] and [5] mentioned in the paper.

It is true that in reality, the Indian transmission system currently uses 400 kV and 132 kV links. The case study presented in section III (and subsequent sections), is not an exact copy of the existing Indian system. It has been developed from only a section of the Indian system, so as to make it more suitable as an illustrative example. The fact that the scenario is a developed one is clearly mentioned in the Introduction of the paper. It should be very clear to the discussers that the objective of the author is only to highlight the various features of the algorithm in question, and not to analyse any practical system.

The scenario presented in the paper involves fifteen utilities, divided into three power pools. Two of these utilities are totally hydro-based, and one is a wheeling utility. The scenario has a total of 192 generating units, of which eighty are emissive. It should be obvious from the complexity of this scenario, that it is virtually impossible to provide an appendix that illustrates the unit characteristics of each individual utility. The author would however be eager to discuss the same with anyone who may be interested.

Considerations of inter-utility transmission capacity limits have been included in the model described, as should be evident from constraint 6 in Appendix 1 of the paper. For details on these, the
interested reader is requested to refer to [4], as mentioned in the paper. However, mixing of fuels has not been taken into consideration, because this does not affect the generality of the algorithm studied in any way. Mixed fuels would merely lead to a change of cost of generation of unit kWhr ($c_i$), and emission coefficients ($e_{ij}$) at the concerned thermal units, and could also lead to a change of the startup cost per kWhr ($sc_{km}$) to some extent. However, it is obvious that the algorithm in question has a definition that is broad enough to include any such variation without any additional computational burden.

The discussors have correctly pointed out that the analysis for the remaining six months of the year brings forth some very interesting results, particularly with reference to seasonal variations of loads. Research in this direction is currently in progress, and the author intends to report the same in some subsequent publication.

Finally, the author would like to thank the discussors for their encouragement, and valuable suggestions regarding future research in this area.

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