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Two-stage algorithm for efficient transmission expansion planning with renewable energy resources

Subir Majumder[1] ✉, R. M. Shereef[2], Shrikrishna A. Khaparde[3]
[1]*Department of Energy Science and Engineering, Indian Institute of Technology Bombay, Mumbai, India*
[2]*Department of Electrical Engineering, College of Engineering Trivandrum, Kerala, India*
[3]*Department of Electrical Engineering, Indian Institute of Technology Bombay, Mumbai, India*
✉ *E-mail: subirmajumder@iitb.ac.in*

Abstract: In this study, a ‘two-stage’ deterministic algorithm an for efficient transmission expansion planning with renewable energy (RE) resources under the assumption that existing conventional generators provide the reserve to mitigate RE generation forecast error has been proposed. Zero-RE penetration has been considered as a ‘reference scenario’, as well as cost-minimisation objective has been considered as a planning criterion in *Stage 1*. In the proposed algorithm, *Stage 2* is required to be solved only if the network performance degrades in relation to the reference scenario. In *Stage 2*, congestion cost is also incorporated as a sub-objective. Here, the locational marginal prices of the unit scheduling problem obtained from the solution of *Stage 1* have been used to calculate the congestion cost. In addition to being computationally tractable, the proposed algorithm guarantees performance improvement in the network. The planning horizon is divided into smaller blocks to facilitate delayed investment. When implemented on an IEEE 24-bus reliability test system, the proposed algorithm generated minimum cost plan with better performance.

Nomenclature

i, j	index representing the bus numbers; $i, j \in \{1, 2, \ldots, N\}$
m, n	index representing the planning blocks; $m, n \in \{1, 2, 3\}$
t	index representing time intervals; $t \in \{1, 2, \ldots, T\}$
$A_{\mathbb{C}}$	consumers' electricity charge attribute
$A_{\mathbb{P}}$	power loss (PL) attribute
$A_{\mathbb{T}}$	total congestion cost attribute
$A_{\mathbb{V}}$	absolute deviation in the voltage profile attribute
C_{ij}	cost of transmission line (TL) connected between node i and j
C_{sw}	cost of spilled renewable energy (RE) generation
d	discount rate to calculate Net Present Value of investment
$F_{i,j,t}$	active power flow between nodes i and j during interval t
$F_{i,j}^{\max}$	active power capacity rating of a TL between nodes i and j
$\mathrm{lmp}_{i,t}^{\mathrm{old}}$	active power pseudo locational marginal price (LMP) at node i during interval t
N_{ij}	proposed number of TLs connected between nodes i and j
$N_{ij}^{\max}$	maximum number of TLs connected between nodes i and j
OC_m	operational cost recovered within planning block m
$\mathrm{OC}_{\mathrm{NPV}}^{\mathrm{total}}$	total operational cost recovered within the planning horizon
$P_{i,t}^{D}$	active load at bus i during interval t
P_t^{N}	capacity penetration of RE generator during interval t
$P_{u,i,t}$	active power generation from generator type u, at bus i, during interval t
$P'_{u,i,t}$	active power generation with reserve from generator type u, at bus i, during interval t
$P_u^{\max}$	maximum active power generation capacity of generator type u
$P_u^{\min}$	minimum active power generation capacity of generator type u
$P_{\omega,i,t}$	active power generation from RE generator ω, connected at bus i, during interval t
$P_{\omega,i,t}^{\max}$	maximum RE generation from RE generator type ω, at bus i, during interval t
PL	total PL in the network
PL_{base}	total PL in the network with reference scenario
$Q_{i,t}^{\mathrm{D}}$	reactive load demand at bus i during interval t
$Q_{u,i,t}$	reactive power generation from generator type u, at bus i, during interval t
$Q_u^{\max}$	maximum reactive power generation capacity of generator type u
$Q_u^{\min}$	minimum reactive power generation capacity of generator type u
T_{I}	number of hours in a sub-interval
TC_m	cost of TLs recovered within planning block m
$TC_{\mathrm{NPV}}^{\mathrm{total}}$	total cost of TLs recovered within the planning horizon
$V_{i,t}$	voltage magnitude at node i during interval t
V_R	reference voltage throughout the network
V_{spec}	specified voltage at the slack bus
$w_{(\cdot)}$	relative weight of an attribute obtained through Analytical Hierarchical Process (AHP)
W	weight of ‘pseudo congestion cost’
$\beta_{(\cdot)}$	linear component of the cost function of a generator
$\gamma_{(\cdot)}$	quadratic component of the cost function of a generator
$\delta_{i,t}$	phase angle of node i during interval t
$\Delta\mathbb{C}$	relative change in customer electricity charge compared with ‘reference scenario’
$\Delta\mathbb{P}$	relative change in PL compared with ‘reference scenario’
$\Delta\mathbb{T}$	relative change in congestion cost compared with ‘reference scenario’
$\Delta\mathbb{V}$	relative change in absolute voltage deviation compared with ‘reference scenario’
σ	weight of ‘cost of TLs’
Φ	set of decision variables for transmission expansion planning (TEP) in *Stage 1*
Φ'	set of decision variables for TEP in decision making stage
Φ''	set of decision variables for TEP in *Stage 2*
κ	standard deviation of forecast error in RE generation

1 Introduction

Transmission expansion planning (TEP) is a major function of transmission network (TN) planners to facilitate electricity trade [1] at minimum investment [2]. Often, planners work with limited budget, and every possible right of way (ROW) has a limited number of corridors. Responding to the growing concerns over climate change, a number of countries have embarked on a mission to reduce greenhouse gas emissions by increasing the share of renewable energy (RE) in their total energy matrix [3]. Installation of more transmission lines will pave way for the introduction of newer RE technologies into the electricity grid [4].

Much of the research on TEP considers the static nature of transmission planning horizon. Of note, the authors [5, 6] provide a comparative study of various mathematical models of TEP. A congestion-driven TEP for a deregulated market has been described in [7]. A bi-level model for TEP within a market environment to minimise network investment cost has been described in [1]. A flat locational marginal price (LMP) approach in TEP to ensure fair and competitive electricity pricing is presented in [8]. Tor *et al.* [9] proposed a multi-year TEP model considering transmission line (TL) congestion and impact of generation investment cost. Zhao *et al.* [10] presented a flexible TEP model based on differential evolution algorithm for cost minimisation while meeting reliability and security criteria. Torre *et al.* [11] described a mixed-integer linear programming model of TEP for competitive electricity pricing.

Research on the integration of RE resources into the TN is notable. Morales *et al.* [12] analysed the impact of wind production on LMP in a pool-based electricity market. Lin [13] presents evidence that a significant improvement in solar energy penetration can provide economic benefits to all the system participants. The impact of wind generators' control strategy, location, and penetration level on electricity pricing and total generation cost has been studied by El-Fouly *et al.* [14]. In [15], using an explicit LMP formulation into the network-constrained unit commitment problem, the impact of demand response and wind generation on LMP has been evaluated.

Yu *et al.* [16] used Taguchi's orthogonal array testing algorithm to present various scenarios of TEP problems taking into consideration load and uncertainties in RE generation. A two-stage solution method based on genetic algorithm and Monte Carlo simulation for a flexible transmission planning with uncertainties in RE generation is presented in [17]. A Markov Chain-based technique for reliability worth/cost analysis with increasing wind penetration level is described in [18]. In [19], the interaction between large-scale wind integration and transmission planning based on coordinated generation and TEP is described.

Khodaei and Shahidehpour [20] proposed a microgrid planning strategy for optimisation of generation and TEP. A probabilistic TEP for investment and loss-of-load minimisation taking into consideration load and wind power uncertainties is described in [21]. A stochastic programming-based tool for adaptive TEP under market and regulatory uncertainties is presented in [22]. The impact of wind generation penetration on transmission system voltage profile and voltage security is described in [23].

The above studies suggest that the primary objective function of TEP could be minimisation of investment for planners, on the other hand, maximisation of welfare for both customers and generators, while maintaining system-level performance parameters like LMP and network voltage level. Although an optimisation problem could be designed to handle several other sub-objectives in addition to cost minimisation while keeping same solution space of the optimisation problem, minimal cost plan may not be achieved.

This study describes a 'two-stage' algorithm on TEP, and has been used to study the impact of various RE penetration levels on TEP. In the first stage, the solution of a TEP problem with objectives of minimisation of cost of new TLs, cost of total energy generation, and spillage of RE is presented. The performance of the network is measured and compared with that for a similar network with zero RE penetration level. It is called as 'reference scenario'. Performance improvement after the addition of RE generators, expressed in terms of composite performance index (CPI), is calculated with respect to the reference scenario. If CPI is inadequate, the second stage of the TEP problem with congestion cost added to the objective function will have to be solved. For calculating the congestion cost, LMPs obtained from the cost minimisation unit-scheduling problem, based on the number of TLs along existing ROWs obtained using *Stage 1* of the algorithm is fixed, are considered. The planning horizon is divided into smaller blocks, and planning for each block is done in a sequence [24]. As a result, this approach is expected to generate a cost minimisation plan, while improving the network performance.

The remaining of this paper is organised as follows. Details of the two-stage TEP are presented in Section 2. Section 3 describes the application of the case study on an IEEE 24-bus reliability test system (RTS), at different penetration levels and locations of RE generators. Section 4 presents the conclusion.

2 TEP algorithm

The level of RE penetration can be defined as the ratio of maximum-capacity of RE-based generators to maximum loading in the network within a planning block [25]. With the addition of RE generators into the TN, network performance may either improve or degrade in comparison to the reference scenario. Thus improvement in network performance is measured with respect to the reference scenario. It is also important to study the impact of different penetration levels of RE resources on transmission expansion, but optimal penetration of RE resources is a different problem, and is not addressed in this work.

The following assumptions are considered in defining the problem:

1. Historical RE generation data is used for transmission planning.
2. TLs are expected to be added only along existing ROWs of a test system.
3. Capacity expansion of RE generators is *decided* in advance.
4. The addition of conventional generators in view of load demand and reserve requirement is fulfilled to mitigate RE generation uncertainty.
5. Under-generation will be met by dispatching conventional generators up to 'one standard deviation' of RE generation forecast error. Over-generation will be curtailed.
6. The location of RE and conventional generators is identified ahead of planning.
7. Annual load growth is equal at all load buses.
8. Six percent loss of load will also be met from the existing generators as a spinning reserve.

Generally a TEP objective function may not contain system performance-related terms. Thus, it cannot be expected that a feasible TEP would generate a 'better performance plan' compared with a reference scenario. Nevertheless, a TEP that incorporates system performance related terms into the objective function will always be costlier. Therefore, system performance-related terms should only be included into the objective function (and thereby optimising it) when the system-level performance of a feasible TEP significantly degrades from a corresponding reference scenario. Therefore, a TEP with two stages is designed. *Stage 1* can be called 'cost minimisation plan' and *Stage 2* as 'better performance plan'. Output of *Stage 1* optimisation problem is essential for the decision-making process. *Stage 1* of the optimisation problem, the decision-making process, and *Stage 2* optimisation problem are elaborated in the following subsections.

2.1 Cost minimisation plan: Stage 1

Stage 1 of the TEP is formulated as a mixed-integer non-linear programming problem for cost-minimisation. The sub-objectives include (i) minimisation of cost of new TLs (planning cost), (ii and iii) minimisation of energy generation cost (maximisation of social welfare), and (iv) maximisation of utilisation of available RE generation (minimisation of spilled RE). Thus, the perspectives of transmission and generation companies and independent RE generators are incorporated into the TEP problem. Spilled RE refers to curtailed energy from RE sources due to insufficient transmission capacity or congestion [26]. The reserve to mitigate RE generation forecast error will be supplied from conventional generators. Therefore, in sub-objective (ii), instead of only minimising generation cost, total dispatch from conventional generators will be minimised to meet load demand and reserve requirement. *Stage 1* of the planning algorithm is formulated as follows:

$$
\begin{aligned}
\min_{\Phi} \quad & \underbrace{\frac{\sigma}{T_I} \cdot \sum_{\substack{i,j \\ i>j}} C_{ij} N_{ij}}_{\text{(i) Cost of new transmission lines}} \\
+ \quad & \underbrace{\sum_{u,i,t} \beta_u P'_{u,i,t} + \gamma_u P'^2_{u,i,t}}_{\text{(ii) Cost of generation from conventional sources}} \\
+ \quad & \underbrace{\sum_{\omega,i,t} \beta_\omega P_{\omega,i,t} + \gamma_\omega P^2_{\omega,i,t}}_{\text{(iii) Cost of generation from RE sources}} \\
& \underbrace{+ C_{sw} \sum_{\omega,i,t} (P^{\max}_{\omega,i,t} - P_{\omega,i,t})}_{\text{(iv) Cost of spilled RE}}
\end{aligned}
\tag{1}
$$

where

$$\Phi := \{N_{ij}, P_{u,i,t}, Q_{u,i,t}, P'_{u,i,t}, P_{\omega,i,t}, V_{i,t}, \delta_{i,t}\} \quad \forall u, \omega, i, j, t$$

subject to,

(a) Set of constraints to dispatch available RE generation

$$\sum_u P_{u,i,t} + \sum_\omega P_{\omega,i,t} - P^D_{i,t} = \boldsymbol{P}^{\mathbf{bus}}_{\boldsymbol{i,t}} \quad \forall i, t \tag{2}$$

$$\sum_u Q_{u,i,t} - Q^D_{i,t} = \boldsymbol{Q}^{\mathbf{bus}}_{\boldsymbol{i,t}} \quad \forall i, t \tag{3}$$

$$\sum\nolimits_\omega P_{\omega,i,t} \le \min\left(\sum\nolimits_\omega P^{\max}_{\omega,i,t}, \sum\nolimits_j F^{\max}_{i,j}\right) \quad \forall i, t \tag{4}$$

$$Q^{\min}_i \le Q_{u,i,t} \le Q^{\max}_i \quad \forall i, u, t \tag{5}$$

$$\left|F_{i,j,t}\right| \le \left|F^{\max}_{i,j}\right| \quad \forall i, j, t \tag{6}$$

$$0 \le N_{ij} \le N^{\max}_{ij} \quad \forall i, j \tag{7}$$

$$0.95 \le V_{i,t} \le 1.05 \quad \forall i \setminus i: \text{slack}, t \tag{8}$$

$$-\frac{\pi}{2} \le \delta_{i,t} \le \frac{\pi}{2} \quad \forall i \setminus i: \text{slack}, t \tag{9}$$

$$V_{i,t} = V_{\text{spec}} \quad i: \text{slack}, \forall t \tag{10}$$

$$\delta_{i,t} = 0 \quad i: \text{slack}, \forall t \tag{11}$$

(b) Set of constraints to meet the reserve to mitigate uncertainty in RE generation by 'one standard deviation' limit

$$\sum_u (P'_{u,i,t} - P_{u,i,t}) = \kappa P^N_t \quad \forall i, u, t \tag{12}$$

$$P^{\min}_u \le P_{u,i,t} \le P'_{u,i,t} \le P^{\max}_u \quad \forall i, u, t \tag{13}$$

The number of TLs ($N_{ij} \in \mathbb{Z}$) to be added along each possible ROW is of primary interest to the planner. The objective function (1) to be minimised is the sum of planning and operational costs incurred within the planning block of the network. Since all the generators are assumed to be scheduled to dispatch, constant parts of generators' cost function are ignored from the objective function. Minimising the cost of spilled RE generation aims to maximise the utilisation of RE-based generation. The amount of spilled RE for all intervals at each bus is calculated using maximum RE generation and evacuation capacity.

TLs have finite lifetime, and the revenue requirement to build these TLs will be recovered throughout its lifetime. A planning block constitutes of multiple intervals *t*; within each interval, the scheduled RE generation and load remains constant. If each of these intervals is constituting of T_I hourly intervals, multiplication of the factor, T_I with the operational cost calculated for each time interval will obtain total operational cost for that block. Similarly, σ is the factor that is used to calculate the revenue requirement within a planning block. Therefore for a given planning block, the weighting factor 'σ/T_I' makes marginal operational (ii)–(iv) and planning costs (i) in the objective function comparable. Sub-objectives can be further weighted to obtain a plan customised to planner's requirements.

Constraints are of two categories based on their purpose: (A) to provide optimal dispatch of conventional and available RE generation to minimise the operation cost, and (B) to meet the reserve from existing conventional generators without violating the ratings of conventional generators. Therefore, in sub-objective (ii), the total costs of generation to meet load demand, network losses and scheduled reserve to be dispatched are jointly minimised. Hence, they are not at their independent minimum level.

Constraints (2) and (3) represent AC power flow to meet the load demand for each interval when RE generators are dispatching power at the level depicted by evacuation capacity and RE generation schedule. $\sum_j F^{\max}_{i,j}$ represents the maximum power a generator can inject without violating the line limit. It is called the 'evacuation capacity' of a bus. Therefore, total RE generation is limited by maximum RE generation available at a time slot and evacuation capacity of the bus at which the RE generator is connected and is presented in (4). In addition, RE generators must operate at unity power factor. Constraint (5) represents maximum and minimum reactive power generation from each conventional generator. Constraint (6) represents the line flow limit of each row corridor. Constraint (7) represents the limit on the maximum number of TLs ($N^{\max}_{ij}$) that can be possibly installed along a ROW. Constraints (8) and (9) impose limits on voltage magnitude and angle at each bus. Constraints (10) and (11) fix voltage magnitude and angle at the reference or slack bus.

Uncertainty in RE generation can be significantly reduced by providing reserve from existing conventional generators. Assuming error in RE generation forecast follows a normal distribution with standard deviation κ, the total reserve provided from all generators is given by one standard deviation (suitably chosen by the planner). The total cost of reserve will be minimised if total reserve power to be provided is supplied from all the generators, instead of from one specific generator, and is depicted in constraint (12). In addition, all conventional generators must operate within their maximum and minimum active power generation limits. Constraint (18) depicts generation limits from conventional generators. Both these equations ensure that if RE generators produce below the schedule, reserve power will be supplied by conventional generators. If RE generators produce above the schedule, excess generation will be curtailed (or spilled).

Consumer demand will be met from existing conventional generators, because they should not be subjected to risk because of limited transmission capacity. However, in the absence of this criterion, the objective function (1) may include such objectives as cost of 'load not served' or cost of 'price-responsive loads'.

2.2 Calculation of LMPs

The marginal cost of the generators obtained by solving the TEP problem is not the actual LMP of generators. To calculate the LMPs, an optimal dispatch problem has to be solved, using the number of TLs obtained after solving the TEP problem. Reserve power to be dispatched from conventional generators to meet either spinning reserve requirement or RE generation uncertainty does not leave any impact on LMPs. The optimisation problem described below is expected to calculate the minimum operational cost and therefore is used to obtain the LMPs of all intervals. A total number of TLs are kept constant.

$$\begin{aligned}\min_{\Phi'} & \sum_{u,i,t} \beta_u P_{u,i,t} + \gamma_u P_{u,i,t}^2 \\ & + \sum_{\omega,i,t} \beta_\omega P_{\omega,i,t} + \gamma_\omega P_{\omega,i,t}^2 \\ & + C_{sw} \sum_{\omega,i,t} (P_{\omega,i,t}^{\max} - P_{\omega,i,t})\end{aligned} \tag{14}$$

where

$$\Phi' := \{P_{u,i,t}, Q_{u,i,t}, P_{\omega,i,t}, V_{i,t}, \delta_{i,t}\} \quad \forall u, \omega, i, j, t$$

subject to

$$\sum_u P_{u,i,t} + \sum_\omega P_{\omega,i,t} - P_{i,t}^D = \boldsymbol{P_{i,t}^{bus}} \quad \forall i, t \tag{15}$$

$$\sum_u Q_{u,i,t} - Q_{i,t}^D = \boldsymbol{Q_{i,t}^{bus}} \quad \forall i, t \tag{16}$$

$$\sum\nolimits_\omega P_{\omega,i,t} \le \min\Big(\sum\nolimits_\omega P_{\omega,i,t}^{\max}, \sum\nolimits_j F_{i,j}^{\max}\Big) \quad \forall i, t \tag{17}$$

$$P_u^{\min} \le P_{u,i,t} \le P_u^{\max} \quad \forall i, u, t \tag{18}$$

$$Q_i^{\min} \le Q_{u,i,t} \le Q_i^{\max} \quad \forall i, u, t \tag{19}$$

$$|F_{i,j,t}| \le |F_{i,j}^{\max}| \quad \forall i, j, t \tag{20}$$

$$0.95 \le V_{i,t} \le 1.05 \quad \forall i \diagdown i: \text{generator}, t \tag{21}$$

$$-\frac{\pi}{2} \le \delta_{i,t} \le \frac{\pi}{2} \quad \forall i \diagdown i: \text{slack}, t \tag{22}$$

$$0.95 \le V_{i,t} \le 1.05 \quad \forall i \diagdown i: \text{slack}, t \tag{23}$$

$$-\frac{\pi}{2} \le \delta_{i,t} \le \frac{\pi}{2} \quad \forall i \diagdown i: \text{slack}, t \tag{24}$$

LMPs are essentially the Lagrange multipliers corresponding to (15) and (16) for all buses at all intervals. Hence, LMP values are *the dual variables of the generation cost optimisation problem, considering transmission plan obtained from Stage 1 or Stage 2 of TEP algorithm.* Since a lossy model of network is considered in this problem, the marginal costs at all buses cannot be the same. In addition, because of congestion in TLs and finite capacity of generators, LMPs throughout the network will not be uniform.

2.3 Decision making using CPI

TL congestion signifies a bottleneck in the flow of electricity to the consumers. The effects of TL congestion are visible in terms of the large values of differential LMPs across the network. System performance is considered to be poor, if there are increases in congestion cost, consumer prices, power losses (PLs) and deviations in voltage profile. Since the cost implications of all these performance attributes are different, these attributes can be combined to calculate a single index, CPI, to determine the performance of the network. In this work, no-RE penetration corresponding to each of the planning block is considered as reference scenario. However, the planner has complete flexibility in choosing an appropriate reference scenario for each planning block.

CPI describes the performance of the network with respect to the reference scenario. It is calculated by combining the weighted normalised values of worst-case performance-related attributes. The weights are obtained by using the Analytic Hierarchy Process (AHP) [27]. These attributes are described below.

2.3.1 Performance attributes: LMPs obtained using the method described in Section 2.2 after fixing the number of TLs to be added along each ROW for that planning block are used to calculate these economic and system performance attributes.

(a) Total congestion cost (TCC): The computation of TCC [28] and its improvement compared with the reference scenario is as follows:

$$\Delta\mathbb{T} = \sum_{\substack{i,j,t \\ i>j}} \left|\text{lmp}_{i,t}^{\text{old}} - \text{lmp}_{j,t}^{\text{old}}\right| \cdot \left|F_{i,j,t}\right| \tag{25}$$

$$A_{\mathbb{T}} = \frac{\Delta\mathbb{T}_{\text{ref}} - \Delta\mathbb{T}}{\Delta\mathbb{T}_{\text{ref}}} \tag{26}$$

(b) Consumer electricity charge (CEC): Assuming that consumers purchase electricity at LMP of that bus, CEC and its improvement compared to the reference scenario is computed as follows:

$$\Delta\mathbb{C} = \sum_{i,t} \text{lmp}_{i,t}^{\text{old}} P_{i,t}^D \tag{27}$$

$$A_{\mathbb{C}} = \frac{\Delta\mathbb{C}_{\text{ref}} - \Delta\mathbb{C}}{\Delta\mathbb{C}_{\text{ref}}} \tag{28}$$

(c) Power loss (PL): With the location and increasing penetration of new generators, the pattern of power flow and thus PL in the network changes. PL and relative reduction in network loss are computed as follows:

$$\Delta\mathbb{P} = \sum_{i,j,t} F_{i,j,t} \tag{29}$$

$$A_{\mathbb{P}} = \frac{\Delta\mathbb{P}_{\text{ref}} - \Delta\mathbb{P}}{\Delta\mathbb{P}_{\text{ref}}} \tag{30}$$

(d) Average voltage deviation (AVD): The average of absolute voltage deviation around a reference voltage at all the buses defines AVD. The computation of AVD and its relative reduction is as follows:

$$\Delta\mathbb{V} = \sum_{i,t} \left|\frac{(V_R - V_{i,t})}{V_R}\right| \tag{31}$$

$$A_{\mathbb{V}} = \frac{\Delta\mathbb{V}_{\text{ref}} - \Delta\mathbb{V}}{\Delta\mathbb{V}_{\text{ref}}} \tag{32}$$

2.3.2 Finding CPI: TL congestion reflects the system performance better compared with other attributes considered. Thus, reduction in congestion cost is given more weight compared with other attributes. The comparison matrix and relative weights calculated using AHP are presented in Table 1.

The equation depicting calculation of CPI is presented as follows:

$$\text{CPI} = w_1 \cdot A_{\mathbb{T}} + w_2 \cdot A_{\mathbb{C}} + w_3 \cdot A_{\mathbb{P}} + w_4 \cdot A_{\mathbb{V}} \tag{33}$$

Table 1 Comparison matrix and relative weights of attributes

Attributes	TCC	CSW	PL	VD	Relative weights, w
TCC	1	4	9	7	0.6224
CSW	1/4	1	6	4	0.2445
PL	1/9	1/6	1	1/3	0.0438
VD	1/7	1/4	3	1	0.0894

2.4 Better performance plan: Stage 2

If the CPI or the performance of the network has degraded with respect to the 'reference scenario', *Stage 2* of the proposed methodology will need to be solved. Therefore, *Stage 2* could be neglected if CPI is positive or approximately zero. The objective function used in *Stage 2* of the optimisation problem is as follows:

$$\begin{aligned}\min_{\Phi''} \ & \frac{\sigma}{T_{\mathrm{I}}} \cdot \sum_{\substack{i,j \\ i>j}} C_{ij} N_{ij} \\ & + \sum_{u,i,t} \beta_u P'_{u,i,t} + \gamma_u P'^2_{u,i,t} \\ & + \sum_{\omega,i,t} \beta_\omega P_{\omega,i,t} + \gamma_\omega P^2_{\omega,i,t} \\ & + C_{sw} \sum_{\omega,i,t} (P^{\max}_{\omega,i,t} - P_{\omega,i,t}) \\ & + \underbrace{W \sum_{\substack{i,j,t \\ i>j}} \left| \mathrm{lmp}^{\mathrm{old}}_{i,t} - \mathrm{lmp}^{\mathrm{old}}_{j,t} \right| \cdot \left| F_{i,j,t} \right|}_{\text{(v) Weighted pseudo congestion cost (PCC)}} \end{aligned} \tag{34}$$

where

$$\Phi'' := \{N_{ij}, P_{u,i,t}, Q_{u,i,t}, P'_{u,i,t}, P_{\omega,i,t}, V_{i,t}, \delta_{i,t}\} \quad \forall u, \omega, i, j, t$$

subject to

$$\text{Equations } (2) - (18)$$

Marginal cost of 'minimisation of operating cost' is used to calculate the LMP ($\mathrm{lmp}^{\mathrm{old}}_{j,t}$), which is then used for computing the congestion cost (as depicted in the objective function). Therefore, the sub-objective (v) that has to be minimised along with the optimisation problem (1) is not the actual congestion cost, but the *sum of absolute value of weighted active power flow through all the TLs*. This modified system congestion cost can be called as pseudo congestion cost (PCC). Weight, W is suitably chosen by the planner to weight congestion cost against rest of the sub-objectives for suitable improvement in performance. In addition, planning cost being the operational cost, it is treated suitably so that investment and operational cost are comparable. The set of constraints in this stage remains the same as described in *Stage 1*. However, *Stage 2* can only be solved after a solution has been obtained from *Stage 1*.

2.5 Discussion

The present work simultaneously views the optimisation problem from different perspectives. A flowchart depicting the proposed method is shown in Fig. 1.

A complete time-horizon is divided into equal smaller blocks. Beginning with the first, an optimal TEP for each block is obtained and then used for finding the TEP of next planning block to utilise the benefit of a delayed investment strategy.

The choice of 'σ', 'C_{SW}', and 'W' is a matter of economic judgement of the planner. The solution space when performance-related terms are used in the optimisation problem, is a subset of solution space of *Stage 1* of the optimisation problem; therefore the total cost of planning and cost of TLs will be higher than before. Since congestion cost is the main performance improvement attribute, PCC is used as a sub-objective in *Stage 2*, along with the objective function from *Stage 1*.

The introduction of this PCC will result in a simplistic planning strategy, because the congestion cost is calculated using LMP values obtained from the previous stage. Hence the calculation of PCC eliminates the need for solving the 'bi-level' problem [1], where power flow equations are assumed to be linear. In addition, solving both the stages sequentially as a part of proposed algorithm will result in reduced cost compared to solving *Stage 2* only.

With increasing penetration of RE generation, the existing generators will require dispatch of reserve depending upon the forecast uncertainty and capacity of RE generators. A TN planning strategy with conventional dispatchable generators providing the reserve into the network is described in [19]. In a deregulated environment, electricity price is decided based on bids of generators and bulk customers, and reserve price is calculated separately using co-optimisation. If the active power is sold to the electricity market at LMPs, provision of reserve from conventional generators must not affect the price.

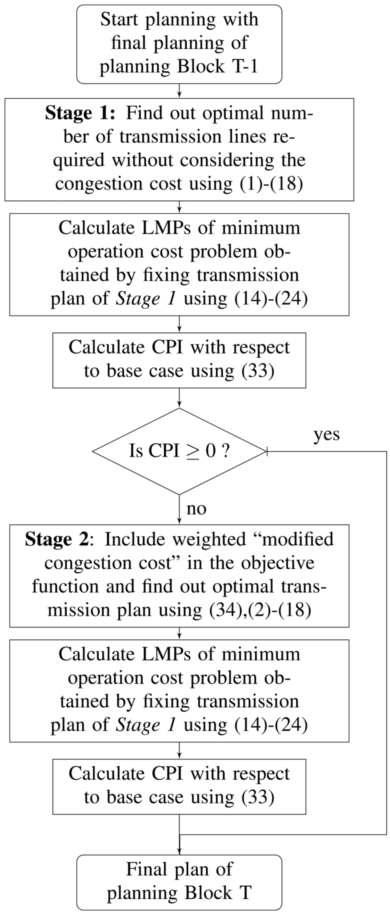

Fig. 1 *Flowchart of two-stage TEP algorithm*

In the proposed method, the total costs of dispatching power to the market and providing the reserve are considered as a part of *Stage 1* and *Stage 2* of the optimisation problem, although generators are not always required to dispatch to provide the reserve. However, in *Stage 1* and *Stage 2* reserve power is not considered a part of power flow equation. In this regard, the total cost of generation to meet load demand is calculated from the unit scheduling problem as described in Section 2.2.

3 Case study

The impact of RE generation on transmission planning based on the proposed methodology has been tested on an IEEE 24-bus RTS [29]. A planning horizon of nine years, consisting of three equally divided planning blocks, is considered. As a part of deterministic planning, each of these three blocks is further broken down into 36 time-intervals to capture the behaviour of RE generation and load growth. A TEP thus obtained for a block must satisfy all the constraints at all time-intervals for a given block. Each stage of the objective function is solved using a standard branch and bound [30] as root-solver and CONOPT [31] as sub-solver, based on a General Algebraic Modelling System [32]. As reported by the solver, the proposed formulation is non-convex, and hence the initial conditions for solving the optimisation problem are varied over a wide range to ensure that the optimal solution obtained is not a local optima. For solving the optimisation problems, a Windows-based system with one Core i3 processor clocking at 2.27 GHz and 4 GB of RAM is used.

A wind turbine generator, assumed to be a typical RE generator, is considered in this work because the analysis can be done independent of the type of RE generator in the network. In addition, the wind generation pattern is independent of wind generation sites chosen and planning year. Historical wind data

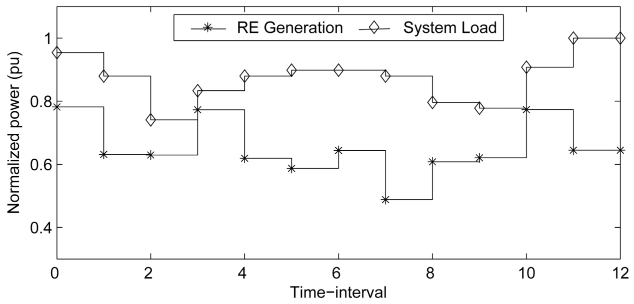

Fig. 2 *Normalised system load and RE generation for 12 time intervals (representing 1 year) out of 36 intervals in a planning block*

from [33] is considered for analysis. A typical normalised wind generation pattern for a year is depicted in Fig. 2. In the beginning, the system had generation capacity of 3405 MW from conventional generators, zero wind energy penetration, and a total connected load of 2850 MW. A typical load pattern for all planning years with recurring 6% annual load growth at all load buses is considered and obtained from [34]. These patterns are depicted in Fig. 2.

Three different cases are presented as a part of this case study. Table 2 shows the schedule of addition of wind and conventional generators. The bus number at which conventional generators are added and their sizing are shown in column three of the table. The addition of conventional generators is done in such a way that, load-generation balance at all the intervals is satisfied. Since conventional generators provide the reserve to mitigate RE generation uncertainty, and spinning reserve, the addition of conventional generators must also account for the reserve requirement. For the purpose of 'one standard deviation limit', the factor κ is selected as 0.13 [35].

No RE generators are added in the 'reference scenario' as shown in Table 2. For consistency, the location and sizing of future addition of conventional generators are assumed to be independent of different penetration levels and location of RE generators. Two different sets of locations of wind generators constitute two cases. In a specific scenario, a wind generator of a specific capacity is added at specific buses. The capacity addition of wind generators in scenario 1 is 175 MW and in scenario 2 is 300 MW. A gradual addition of RE generators is considered. Therefore, in case 1, and scenario 1 at the beginning of 2nd, 3rd, 5th, 8th, and 9th planning year, at bus numbers 3, 4, 6, 10, and 5, respectively, wind generators of 175 MW are added. Therefore, at the end of the planning period, total capacity addition of wind generators is 875 MW. Similarly, in case 2, and scenario 2 at the beginning of 2nd, 3rd, 5th, 8th, and 9th planning year at bus numbers 13, 11, 16, 8, and 12, respectively, wind generators of 300 MW are added. At the end of planning horizon, the system has a load of 4815 MW, generation of 5102 MW from conventional generators and generation of 875 MW for scenario 1 (or 20% wind penetration) and 1500 MW for scenario 2 (or 30% wind penetration) from wind generators.

The new TLs have a life of 35 years, and the investment made or the revenue requirement will be recovered throughout its lifetime at an annual discount rate of 3%. Therefore, in the optimisation problem, the discount rate, d is selected as 3%, to calculate the net present value (NPV) of the investment. Since each planning block constitutes three years; σ is calculated as 0.13 to account for the cost of new TLs recovered in three years. However, choosing different values of σ will significantly affect the planning. Each smaller instance in a block represents a month to account for monthly variation in wind generation and load. Assuming each month constitutes of 30 days, or 720 h, T_I is selected as 720 to account for the total cost of energy. C_{SW} is chosen as \$400/MWh, which is approximately four times the average marginal cost of all generators. This high value ensures minimum wastage of wind energy because of limited evacuation capacity. In *Stage 2* of transmission planning, W is arbitrarily selected as 100.

The cost of additional TLs and cost function of existing conventional generators are taken from [36]. Conventional generators of similar capacity and rating are pre-selected for expansion planning, and their cost function is similar to that of existing generators.

Apart from maintenance cost, there could be no variable cost component in renewable generation installation. The marginal cost of RE generation is obtained by dividing total power generation from RE generators by the NPV of installation and annual maintenance cost. Therefore, in order to recover the investment cost, the RE generators must adjust their tariff. In contrast to conventional generators, where marginal cost of generation is a function of fuel consumed or generation during that hour, the marginal cost of RE generators is constant. In the absence of any special tariff rate imposed by the regulator to promote integration of clean energy into the grid, the tariff of renewable generation will be solely dictated by installation and maintained cost, and capacity factor of renewable generation at that specific site. Therefore, instead of wind energy generators, if other types of generators were to be considered, the procedure for calculation of marginal cost of RE generation will remain the same with associated changes in marginal cost. addition of wind generators with constant and negligible marginal cost [37], will significantly modify the transmission plan.

Investment in TLs will be recovered over their lifetime. For simplification, we assume that recoverable investment within a planning block is received at the beginning of a planning block. Similarly, the operational cost is incurred at the beginning of a planning period. Therefore, NPV of recoverable investment and NPV of operational costs during the planning horizon are calculated as follows:

$$TC_{\text{NPV}}^{\text{total}} = \sum_{m=1}^{3} \sum_{n=m}^{3} \frac{1}{(1+d)^{3\cdot(n-1)}} TC_m \tag{35}$$

$$OC_{\text{NPV}}^{\text{total}} = \sum_{m=1}^{3} \frac{1}{(1+d)^{3\cdot(m-1)}} OC_m \tag{36}$$

Similarly, NPVs of recoverable investment and operational costs are calculated for all possible cases and scenarios for comparison.

Table 2 Siting and capacity addition of conventional and wind generators

Planning horizon	Planning year	Conventional generator addition	Wind generator addition		
			Scenarios 1 and 2 (wind generators of different sizing)		
			Reference	Case 1	Case 2
Block 1	1	—	–	–	–
	2	—	–	3	13
	3	13 (197 MW)	–	4	11
Block 2	4	18 (400 MW)	–	–	–
	5	—	–	6	16
	6	18 (400 MW)	–	–	–
Block 3	7	23 (350 MW)	–	–	–
	8	—	–	10	8
	9	13 (350 MW)	–	5	12

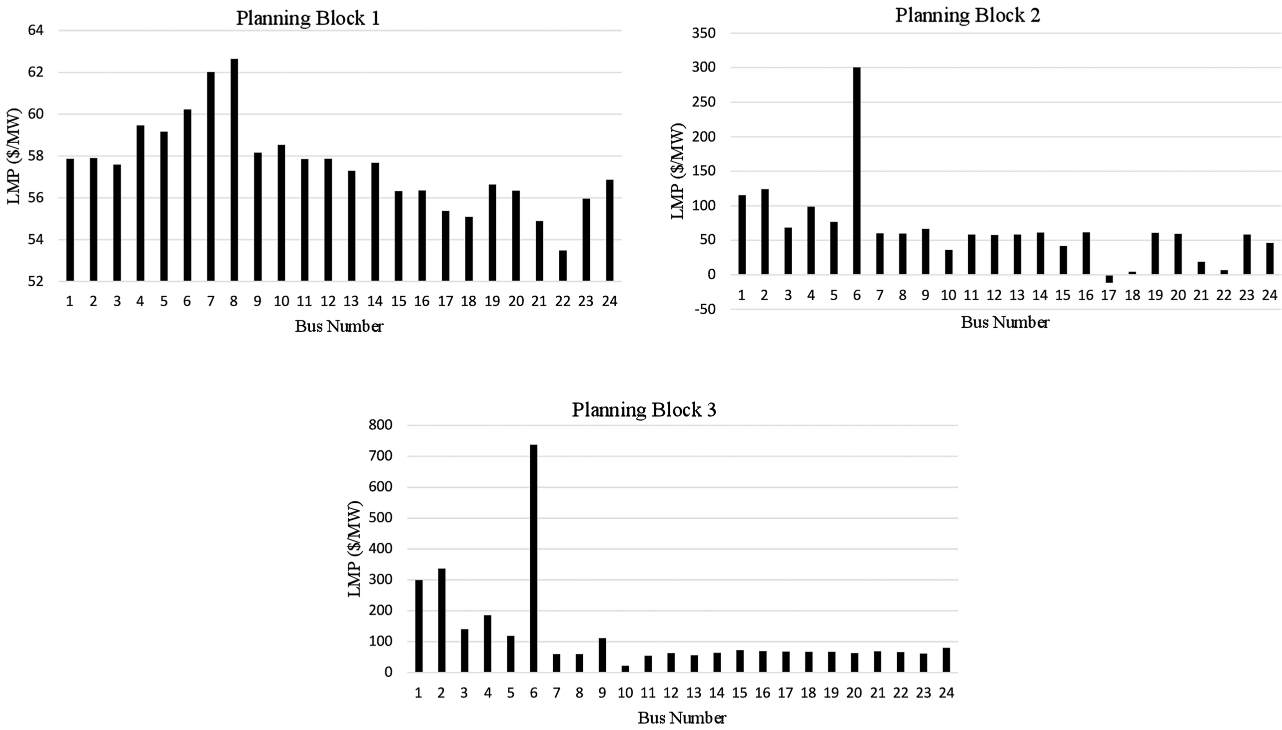

Fig. 3 *LMPs at all buses at* 36th *time-interval of each planning block in the reference scenario*

3.1 Reference scenario

Without the addition of RE generators, the economics of TEP, so obtained in this scenario is shown in Table 3. The investment cost of TLs presented in the table is the total cost of TLs, or the total revenue requirement. The cost of generation of conventional generators is the generation cost of each block. Total cost incurred during the planning horizon is calculated using (35) and (36). Similarly, the economics of transmission planning in other scenarios is also presented for analysis.

As load demand increases, conventional generators have to dispatch more, leading to an increase in the cost of generation. Although the load demand is rising at a constant rate, since the coefficients of cost function of all conventional generators are different, the cost of generation of conventional generators does not increase uniformly.

The LMP values of 36th time-interval of each block are the worst among all intervals in a planning block. The LMP values of 36th time-interval for all three planning blocks are presented in Fig. 3 for comparison. According to the figure, the LMPs at different buses of a particular block are not constant, and also there is a wide variation in LMP values for the given time-intervals in all three blocks. Non-uniform LMP values at 36th time interval, can be attributed to the highest load demand among all time intervals leading to a network congestion. With an increase in the number of TLs, congestion may reduce, thereby further reducing the total generation cost. Therefore, the higher congestion cost can be attributed to increase in the marginal TL investment cost compared to the marginal cost of decrease in generation cost from conventional generators.

There can be a provision to improve network performance further by selecting appropriate reference scenario, and the proposed methodology. However, in this work, no RE scenario is selected as a reference for a comparative analysis with increasing wind energy penetration. Hence, a network that is performing better than a reference scenario is always desirable.

Table 3 Economics of reference scenario of TEP

Planning horizon	TL plan	TL investment cost, M$	Conventional generation cost, M$/block	CPU time, h
Block 1	11–13(3), 12–23, 15–24(2)	238.00	123.64	0.92
Block 2	15–21	34.00	140.80	2.18
Block 3	2–6, 4–9, 5–10, 7–8(3), 8–10, 11–13(6), 12–23, 13–23, 15–16, 15–21, 15–24	598.00	146.60	3.50
	Total cost	158.02	375.26	

Table 4 Improvement in system performance attributes, if Stage 2 is solved along with Stage 1, and associated change in ROW cost with respect to the reference scenario

Planning horizon	Planning scheme	$A_{\mathbb{T}}$, %	$A_{\mathbb{C}}$, %	$A_{\mathbb{P}}$, %	$A_{\mathbb{V}}$, %	Relative TL cost
Block 1	Stage 1 only	19.02	29.50	−8.00	−5.20	−0.75
	Stage 1 + 2	60.94	29.50	49.00	26.50	−0.43
Block 2	Stage 1 only	21.03	42.70	7.00	−5.00	0.97
	Stage 1 + 2	96.33	52.70	82.00	27.30	52.74
Block 3	Stage 1 only	39.37	37.50	26.00	5.80	−0.41
	Stage 1 + 2	98.45	48.00	85.00	27.90	2.32

3.2 Improvement in performance attributes at Stage 2

Performance attributes and relative increase in the cost of new TLs to be added in scenario 2 of case 2 are presented in Table 4. The decision making stage to obtain an optimal TEP is ignored in this regard. In 'Stage 1 only' planning scheme, optimal TEP corresponding to each of the planning block is obtained by solving only Stage 1 of proposed methodology; and optimal TEP of subsequent block is calculated considering TEP obtained in the previous block. Hence, Stage 2 of the optimisation problem is not solved in this regard. In 'Stage 1 + 2' planning stage, optimal TEP corresponding to each of the planning block is performed by considering Stage 1 of the proposed methodology. Independent of the value of CPI, *Stage 2* is solved. TEP of the subsequent block is calculated considering the TEP obtained from *Stage 2* of the previous block.

The table shows a comparison of improvement in performance attributes in 'Stage 1 + 2' and 'Stage 1 only' planning schemes. Since, *Stage 2* is compulsorily solved in the 'Stage 1 + 2' planning scheme, and PCC is a part of the optimisation problem in *Stage 2*,

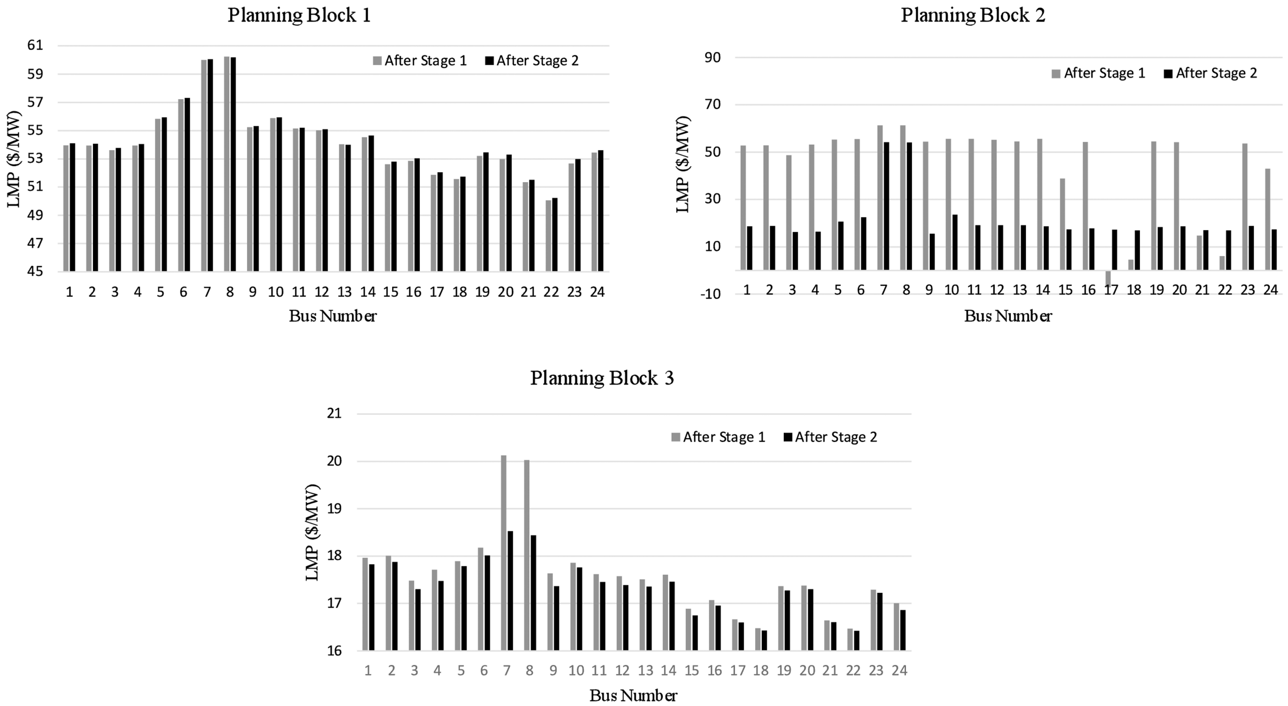

Fig. 4 *Comparison of LMPs at all buses at* 36th *time-interval of each planning block in case 1 of scenario 1 when both Stage 1 and Stage 2 are sought*

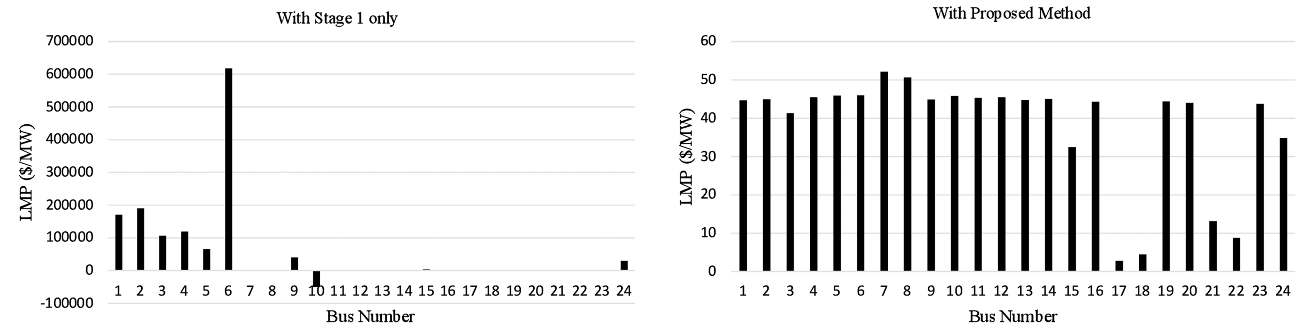

Fig. 5 *Improvement in LMPs at* 36th *interval in block 2 of scenario 2 of case 2 of the case study, where CPI after Stage 1 of planning process is negative*

improvement in congestion cost is significant compared to other attributes. Improvement in $A_{\mathbb{T}}$ indicates that differential LMPs among the buses are further minimised compared with 'Stage 1 only' planning scheme; and improvement in $A_{\mathbb{C}}$ indicates that LMPs at the buses at which customers are connected are comparably reduced. LMPs at all the buses, in 'Stage 1 only' and 'Stage 1 + 2' planning schemes for 36th time interval (worst case) for all three planning blocks are presented in Fig. 4. The figure demonstrates that worst-case LMPs at all buses are improved and uniformised if PCC is a part of the optimisation problem, which is to be solved in the second stage of optimisation problem.

Improvement in $A_{\mathbb{V}}$ indicates that voltage at all the buses is more uniform compared to the reference scenario. However, the improvement in performance attributes is obtained at a cost of increase in the cost of TLs. If a marginal reduction in modified congestion cost with the addition of an extra TL is higher compared with an increase in the total cost of TLs, the additional investment cost in TLs is justifiable. A maximum possible reduction in congestion cost is also subject to the maximum number of possible TLs. An improvement in performance attributes is also subject to the weight (W), which is selected at planner's discretion. Moreover, notably, for a marginal performance improvement, an increase in transmission cost can be very high. Thus, *Stage 2* of the TEP is considered only when the performance of the TN is degraded in comparison to a reference scenario.

3.3 Improvement in LMP with two-stage planning

The proposed two-stage planning strategy is implemented on each of the planning blocks for all two scenarios of two cases. When the CPI was negative, TEPs with better system performance were obtained by solving *Stage 2* of the proposed methodology. In this work, *Stage 2* was required to be solved only in block 2 of scenario 2 of case 2. Improvement in LMPs and differential LMPs at 36th time-interval is presented in Fig. 5.

In this problem, the CPI is found to be improved from −184.99 to 0.67 when *Stage 2* was solved as well. The TEP of block 3 is obtained using the TEP obtained from *Stage 2* of block 2. Since the CPI obtained in *Stage 1* of block 3 is positive, *Stage 2* is not required to be solved. Therefore, as explained in the earlier subsection, since *Stage 2* is required to be solved only in block 2 of scenario 2 of case 2, total planning cost is significantly reduced.

3.4 Impact of different wind energy penetration levels on transmission planning

New line addition with *Stage 1* for different scenarios and cases are calculated using the proposed algorithm, and are shown in Table 5 for analysis. A comparative analysis of the economics of transmission planning is also presented in Table 6. The following results of the TEP problem signify the impacts of increased wind-energy penetration level on the number of ROWs and total cost of generation: (i) economics of *Stage 1*, (ii) associated CPI, (iii) economics of *Stage 2* (if required), and (iv) CPI of *Stage 2* (if *Stage 2* is solved). All these results are summarised in Tables 5 and 6 for comparison.

With increasing penetration level of wind generators, the requirement for reserve increases. Since the sub-objective is so selected that the total dispatch from conventional generators is minimised, the cost of generation from conventional generators is significantly higher compared with generating cost to balance the load demand only. The total operational cost of generators considering energy and reserve alike is presented under 'Generation and Reserve cost' of Table 6. The cost of generation to meet the load demand can be calculated from the method described in Section 2.2.

Table 5 shows that, in planning block 1 of case 2, with an increase in RE penetration level, the CPI gets degraded. Therefore, it is evident that an increase in wind penetration does not guarantee an improvement in system performance.

Simulation results show that *Stage 2* of the TEP is not required to be solved in most of the cases because the CPI may be either positive or close to zero. This implies that congestion in most of the cases is comparatively smaller than the 'reference scenario'. In other words, the transmission plan is being benefited from reduction in cost because of delayed investment.

With similar penetration levels of wind generation, with different location of wind generators the costs of reserve differ. Incremental cost of TLs leads to line congestion, resulting in the under-utilisation of generating resources, thereby increasing the total cost. In some cases, without the introduction of new TLs, the system is able to cater to the load demand. However, in general, the evacuation of RE generation from source to load will require additional TLs. It is also evident that TL investment cost is independent of penetration level of RE generator.

Table 6 shows that increasing penetration of RE generation will reduce the cost of total power production, given the decrease in generation cost is higher compared with increase in cost of TLs. Reduction in the total cost is also depending on location of RE generators. Therefore, insufficient evacuation capacity (even-if *Stage 2* of the algorithm is solved) can cause spillage of wind generation.

That the solution of the TEP obtained using the DC optimal power flow algorithm will be AC-feasible cannot be assured. The incorporation of AC load flow equations will lead to a rise in the complexity of the problem and increase the simulation time. Nevertheless, given that the problem of interest is a planning problem, an average simulation time of 2 h is reasonable. Although a conventional optimisation technique is used for solving both the stages of the optimisation problem, other techniques (such as heuristics) may also be used, provided they generate the dual variables to calculate $\text{lmp}(i, t)^{\text{old}}$.

Representation of reduction in the cost of TLs because of delayed investment strategy requires a base line. A possible modification of the steps of the algorithm that provides the base-line to obtain additional information on the benefits or adversities of increasing RE penetration is described below:

i. Calculate the number of possible TLs to be added for the complete planning horizon for the reference scenario. Solve *Stage 2* as well, which will guarantee better performance of the reference scenario.
ii. Calculate the number of possible TLs to be added sequentially for the reference scenario. Solve *Stage 2* as well. Total number of TLs to be added along a ROW will be limited by the total number of TLs as calculated in step (i).
iii. Calculate the number of possible TLs to be added for the complete planning horizon for all the cases and scenarios. Solve *Stage 2* as well, which will guarantee better performance for those individual cases and scenarios.

Table 5 TEP for all the cases under scenarios 1–3. Improvement in CPI with Stage 2 of the proposed algorithm, change in ROW plan and simulation time are presented in bold

Planning horizon	Planning stage	Transmission line plan	CPI	CPU time, h	Transmission line plan	CPI	CPU time, h
			Case 1			Case 2	
Scenario 1: Capacity penetration of 875 MW from RE generators							
Block 1	Stage 1	13–23(1)	0.18	1.12	8–10(4), 11–13, 14–16(2)	0.26	0.99
Block 2	Stage 1	12–23(1)	0.23	2.50	2–4, 15–24	0.40	1.70
Block 3	Stage 1	8–10(6), 12–23, 19–20	0.35	1.28	1–3(1), 2–6(4), 12–13(3)	0.25	2.14
Scenario 2: Capacity penetration of 1500 MW from RE generators							
Block 1	Stage 1	8–10(1), 13–23	0.29	1.67	—	0.08	0.52
Block 2	Stage 1	—	0.46	2.33	17–18, 19–20, 20–23	−184.99	5.55
	Stage 2	—	—	—	**1–3, 2–6(6), 4–9(3), 5–10(6), 8–10, 14–16, 15–24(6), 17–18(5), 19–20, 20–23**	**0.67**	**1.11**
Block 3	Stage 1	7–8, 8–10, 12–23(2)	0.49	1.40	2–4, 5–10, 7–8(3), 8–10(3), 11–14(2), 12–23(3), 16–17	0.70	3.17

Table 6 Economics of TEP problem under different cases and scenarios

Planning horizon	Planning stage	Conventional generation cost, M$/block		Renewable generation cost, M$/block		Spilled renewable cost, M$/block		Generation and reserve cost, M$/block		TL investment cost, M$	
		Case 1	Case 2	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
Scenario 1: capacity penetration of 875 MW from RE generators											
Block 1	Stage 1	114.72	114.27	0.61	0.61	0.00	0.00	116.00	115.57	60.00	259.00
Block 2	Stage 1	121.01	120.07	1.59	1.59	0.00	0.00	124.03	122.07	67.00	69.00
Block 3	Stage 1	132.72	131.29	2.38	2.38	0.00	0.00	133.40	131.32	352.50	354.00
total cost		336.61	334.10	4.06	4.06	0.00	0.00	341.23	337.26	75.11	146.94
Scenario 2: capacity penetration of 1500 MW from RE generators											
Block 1	Stage 1	110.22	110.53	1.04	1.04	0.00	0.00	117.99	112.25	103.00	0.00
Block 2	Stage 1	110.99	113.77	2.72	2.71	0.00	2.71	113.24	115.89	0.00	52.50
	Stage 2	—	111.83	—	2.12	—	2.72	—	215.56	—	725.50
Block 3	Stage 1	117.88	111.74	4.08	4.08	0.00	0.00	120.16	115.73	193.00	510.00
total cost		310.51	306.45	6.95	6.40	0.00	2.27	322.25	406.44	57.57	220.71

iv. Calculate the number of possible TLs to be added sequentially for each case and scenario. The total number of TLs to be added along a ROW will be limited by the total number of TLs as calculated in step (iii), corresponding to that case and scenario.

4 Conclusion

This study proposes a two-stage TEP algorithm and discusses the utility of this algorithm to study the impact of different penetration levels and locations of RE generators on transmission planning. A strategically selected sub-objective is included in *Stage 2* along with the usual cost-minimisation objective function, based on the network performance indices. *Stage 1* of the objective function minimises weighted cost of TN, total cost of generation and reserve, cost of RE generation and cost of curtailed or spilled RE generation. The reserve is provided to minimise the RE forecast uncertainty, and to supply spinning reserve. A CPI is used to determine network-performance improvement for solving *Stage 2*. Network performance attributes such as congestion cost, consumer prices, network loss, and averages of absolute voltage deviations are considered for calculating the CPI. Since an improvement in network performance will increase the total cost, the proposed two-stage algorithm ensures an optimal cost plan for the network with different RE penetration levels and locations of generators.

The proposed methodology is tested on an IEEE 24-bus RTS. PCC is used as a sub-objective in *Stage 2*. The simulation results show that PCC can effectively reduce network congestion, and improve CPI. Different scenarios and cases are solved using the proposed algorithm, suggesting a reduction in generation cost in comparison to 'reference', and '*Stage 1 only*' scenario. The case studies also show that transmission planning is influenced by various levels of RE generation and their locations. The proposed methodology can provide a useful decision support for the transmission planners and with varying levels of RE penetration. A possible modification to utilise the benefit of delayed investment strategy is also proposed in this paper, which remains to be verified in a future study.

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