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Transmission Expansion Planning Considering Power Losses, Expansion of Substations and Uncertainty in Fuel Price Using Discrete Artificial Bee Colony Algorithm

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ABSTRACT Transmission expansion planning (TEP) is an important part of power system expansion planning. In TEP, optimal number of new transmission lines and their installation time and place are determined in an economic way. Uncertainties in load demand, place of power plants, and fuel price as well as voltage level of substations influence TEP solutions effectively. Therefore, in this paper, a scenario based-model is proposed for evaluating the fuel price impact on TEP considering the expansion of substations from the voltage level point of view. The fuel price is an important factor in power system expansion planning that includes severe uncertainties. This factor indirectly affects the lines loading and subsequent network configuration through the change of optimal generation of power plants. The efficiency of the proposed model is tested on the real transmission network of Azerbaijan regional electric company using a discrete artificial bee colony (DABC) and quadratic programming (QP) based method. Moreover, discrete particle swarm optimization (DPSO) and decimal codification genetic algorithm (DCGA) methods are used to verify the results of the DABC algorithm. The results evaluation reveals that considering uncertainty in fuel price for solving TEP problem affects the network configuration and the total expansion cost of the network. In this way, the total cost is optimized more and therefore the TEP problem is solved more precisely. Also, by comparing the convergence curve of the DABC with that of DPSO and DCGA algorithms, it can be seen that the efficiency of the DABC is more than DPSO and DCGA for solving the desired TEP problem.

INDEX TERMS DABC, static TEP (STEP), uncertainty in fuel price, network losses, expansion of substations.

NOMENCLATURE

SETS

- Ω Set of candidate corridors for network expansion.

INDICES

- c Index for transformer type.
- i Index for buses.
- t Index for time.

PARAMETERS

- C_{MWh} Cost of one MWh ($/MWh).
- CL_{ij} Installation cost of transmission lines in corridor between buses i and j.

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d_i	Active power demand of bus i.
d	Vector of load demand.
$\overline{f_{ij}}$	Maximum active power of corridor between buses i and j.
$\overline{g}$	Vector of maximum generation.
LGF^k	Load growth factor in scenario k.
$\overline{m_i}$	Maximum number of transformers than can be installed on bus i.
n_{ij}^0	Number of initial line circuits in corridor between buses i and j.
$\overline{n_{ij}}$	Maximum number of line circuits in corridor between buses i and j.
NB	Number of buses.
NC	Number of candidate corridors for expansion of transmission network.
NY	Number of years after expansion to calculate losses.
R_{ij}^k	Line resistance of corridor between buses i and j in scenario k.
SC_c	Cost of transformer of type c.
ST	Number of transformer types.
T	Planning horizon (year)
α	Weighting factor of loss of load (LOL).
γ_{ij}^k	Line susceptance of corridor between buses i and j in scenario k.

VARIABLES

g_i^k	Generation on bus i in scenario k.
$I_{ij,t}^k$	Current flow of corridor between buses i and j in year t under scenario k.
m_i^k	Number of expected transformers that should be installed on bus i in scenario k.
n_{ij}^k	Number of new line circuits installed within corridor between buses i and j in scenario k.
r_i^k	LOL of bus i in scenario k.
θ_i^k	Voltage phase angle of bus i in scenario k.
θ_j^k	Voltage phase angle of bus j in scenario k.
δ_i^k	Load supplying coefficient of bus i in scenario k.

FUNCTIONS

EC_k	Network expansion cost in scenario k.
f^k	Vector of lines active power in scenario k.
g^k	Vector of generation in scenario k.
GC_i^k	Power generation cost on bus i in scenario k.
LC_k	Network losses cost in scenario k.
S	Matrix of network structure.
δ_k	Vector of load supplying coefficient in scenario k.

I. INTRODUCTION

Transmission expansion planning (TEP) is a sub-problem of power system expansion planning problem that its main goal is optimizing network expansion costs [1]. TEP is categorized into static transmission expansion planning and dynamic one. Optimal location and number of new transmission lines are determined in the static expansion planning while in dynamic one, installation time of new lines are specified in addition to their optimal place and numbers [2].

Garver was the first researcher who solved the TEP problem in 1970 [3]. After him, many researchers tried to solve the static transmission expansion planning (STEP). Some of them proposed new solution methods for the problem. Some others considered uncertainty [4], [5], reliability indices [6], [7], and economic aspects [8] in STEP problem and some of them studied simultaneous transmission and generation expansion planning [9]. However, impact of fuel price uncertainty on expansion of transmission lines and substations have been studied by none of these researchers.

In [10], a linearized power flow model using the Benders decomposition was applied to formulate the STEP problem. However, Benders decomposition as a classical optimization method may fail to find the optimal solutions because of the non-convexity of the TEP problem. In order to resolve this issue, the Benders hierarchical decomposition approach (HIPER) was introduced in [11]. However, the proposed approach still included non-convexities. In addition, important issues such as power losses, expansion of substations and uncertainties have not been included in formulations of [10] and [11].

A greedy randomized adaptive search procedure (GRASP) was presented by [12] in order to solve the static transmission expansion planning problem. Although GRASP is a powerful heuristic method for solving many kinds of optimization problems, it is a time-consuming method to solve large-scale STEP problems, especially when power losses, expansion of substations, and uncertainties are considered beside expansion cost of transmission lines.

In [13], branch and bound (B&B) algorithm was applied to solve a linear STEP problem. However, slow convergence and hard implementation are the main disadvantages of this algorithm if the nonlinear terms such as power losses are added to objective function. A sensitivity analysis based method for static transmission expansion planning neglecting expansion of substations and generation uncertainties was proposed in [14]. Nevertheless, finding optimal solutions in reasonable computational time is not possible when there are large number of buses or/and candidate corridors for expansion in the network.

Simulated annealing (SA) was presented in [15] in order to minimize the investment cost and network loss of load (LOL) in STEP. SA is a robust point-to-point search optimization algorithm. However, the convergence speed of the algorithm and quality of solutions are low in combinatorial STEP problems because of an increase in the number of alternatives and the number of local minimum points. In order to improve the SA performance, parallel simulated annealing (PSA) was proposed in [16] to solve the problem of [15]. The results showed lower computational time and higher quality of solutions compared to SA. Nevertheless, implementation of PSA on large-scale combinatorial STEP problems is not easy. Moreover, power losses, substation expansion, and uncertainty issues have been ignored in [15] and [16].

In [17], a new method based on artificial neural network (ANN) was proposed to solve STEP problem, considering power losses and lines construction cost. The network expansion cost and power flow of transmission lines were included in an objective function of the STEP problem in [18]. The goal was simultaneous optimization of expansion planning costs and lines loading. Nevertheless, expansion of substations as well as generation uncertainties have not been embedded in the proposed models of [17] and [18].

In [19] and [20] thyristor-controlled series compensators (TCSC) were considered in a flexible TEP problem using Benders decomposition. It was shown that investment in new lines is more attractive than investment in TCSC, but important issues such as expansion of substations and uncertainty in fuel price have not been considered in [19] and [20].

In [21], a particle swarm optimization (PSO) and quadratic programming (QP) based method was employed to solve a TEP problem considering power losses and the N-1 security criterion, but N-1 security analysis has not been undertaken for all transmission topologies. Moreover, expansion of substations and generation uncertainty have been ignored by [21]. Also, in [1], wind energy and network contingencies were included in TEP problem based on the quantile value of each plan cost without considering substation expansion and fuel price uncertainty.

In [22], demand and renewable generation uncertainties were included in TEP problem, disregarding uncertainties in electricity generation of conventional power plants such as fuel price uncertainty. Whereas, thermal electricity generation still consists of a notable part of electrical power generation.

In [23], the high voltage direct current (HVDC) transmission lines were included in dynamic TEP formulation, emphasizing renewable generation. However, the TEP problem has been solved regardless of generation uncertainties of conventional power plants (e.g. fuel price).

In [24], the TEP problem has been solved in a deregulated electricity market considering load uncertainties using a bacterial foraging algorithm. Also, the voltage security of each considered plan was provided by the voltage stability index. Nonetheless, the STEP problem has been solved regardless of substations expansion and uncertainty in fuel price. The fuel price is an important factor in power system expansion planning that includes severe uncertainties. This factor indirectly affects the lines loading and subsequent network configuration by changing the optimal power generation of power plants.

So far, different kind of global optimization techniques like genetic algorithm (GA) [7] and Tabu search [25] have been proposed to solve STEP problem. Although these algorithms are good techniques to solve TEP problems, their efficiency is degraded to obtain the global optimum solution in reasonable computing time when there are large number of parameters in the objective function. In order to overcome these shortcomings, a discrete particle swarm optimization (DPSO) algorithm was proposed to minimize expansion and maintenance costs in [2]. The DPSO is a useful optimization algorithm that its high flexibility and ability in finding the global and local optimums had made it a powerful metaheuristic technique. However, becoming particles more and more similar during the algorithm search makes the swarm premature convergence around the local solution. In order to resolve this problem and including fuel price uncertainty in transmission expansion planning, the STEP problem considering network losses and uncertainty in fuel price using a discrete artificial bee colony (DABC) algorithm is solved in the present work. Among the metaheuristic methods, artificial bee colony (ABC) has better performance to solve such complex non-linear TEP problem [26].

The proposed objective function includes the lines construction cost and the expansion cost of related substations from the voltage level point of view. In order to demonstrate the effectiveness and robustness of the proposed model, the proposed DABC method is tested on a real transmission network of the Azerbaijan regional electric company in comparison with DPSO approach and decimal codification GA (DCGA) method developed by [7]. The evaluation of results shows that considering the effect of fuel price uncertainty in expansion planning of transmission systems causes more exact calculation of the expansion and operation costs of network. Also, by comparing the convergence curve of the DABC with convergence plots of DPSO and DCGA, it can be seen that the efficiency of the DABC algorithm is more than DPSO and DCGA for solving the desired STEP problem. Therefore, the main contribution of current study compared to other research works is analyzing impact of fuel price uncertainty on transmission expansion planning problem considering expansion of substations from the voltage level point of view.

II. PROBLEM FORMULATION

The proposed TEP problem is formulated using DC power flow. The DC power flow model has been proved to be the most common representation of the transmission system within network expansion planning approaches [27].

A. THE PROPOSED STEP MODEL

Due to considering the losses, voltage level, uncertainty in fuel price, and power demand expansion for solution of STEP problem, the proposed objective function is defined as follows:

$$Min\ OF_k = EC_k + LC_k + \alpha \times \sum_{i=1}^{NB} r_i^k + \sum_{i=1}^{NB} GC_i^k \tag{1}$$

where:

$$EC_k = \sum_{i,j \in \Omega} CL_{ij} \times n_{ij}^k + \sum_{i=1}^{NB} \sum_{c=1}^{ST} m_i^k \times SC_c \tag{2}$$

$$LC_k = \left(\sum_{t=1}^{NY} \sum_{i=1}^{NC} R_{ij}^k \times I_{ij,t}^{k2} \right) \times K_{loss} \times 8760 \times C_{MWh} \tag{3}$$

$$GC_i^k = a_i^k \times (g_i^k)^2 + b_i^k \times g_i^k + c_i^k \tag{4}$$

subject to:

$$Sf^k + g^k - \delta^k d \times (1 + LGF^k)^T = 0 \tag{5}$$
$$f_{ij}^k - \gamma_{ij}^k(n_{ij}^0 + n_{ij}^k)(\theta_i^k - \theta_j^k) = 0 \tag{6}$$
$$\left|f_{ij}\right|^k \leq (n_{ij}^0 + n_{ij}^k)\overline{f_{ij}} \tag{7}$$
$$0 \leq g^k \leq \overline{g} \tag{8}$$
$$0 \leq n_{ij}^k \leq \overline{n_{ij}} \tag{9}$$
$$0 \leq m_{ij}^k \leq \overline{m_i} \tag{10}$$
$$0 \leq \delta^k \leq 1 \tag{11}$$

The first, second, third, and fourth terms of the objective function (1) indicate costs of network expansion, active losses, loss of load (LOL), and generation, respectively. Equation (2) shows that expansion network cost consists of expansion costs of transmission lines (first term) and substations (second term). Equations (3) and (4) express active power losses cost and generation cost, respectively. The losses are calculated according to predicted power demand at planning horizon. Also, the method for calculation of losses coefficient (K_{loss}) has been mentioned in [7]. Equations (5) and (6) describe nodal active power balances and DC power flow equations, respectively. (7) shows line power flow constraint and expressions (8) to (11) describe power generation limit, permissible number of constructible lines and transformers in each corridor and buses, and load supplying coefficient restriction, respectively.

B. OPTIMAL POWER FLOW BASED ON QUADRATIC PROGRAMMING

By replacing (4) in the fourth term of (1), the following equation is obtained.

$$GC^k = \sum_{i=1}^{NB} GC_i^k = \sum_{i=1}^{NB} a_i^k \times (g_i^k)^2 + b_i^k \times g_i^k + c_i^k \tag{12}$$

Equation (12) is modified as follows to include the loss of load cost:

$$\begin{aligned} GC^k &= \sum_{i=1}^{NB} GC_i^k + \alpha \times (1 - \delta_i^k) \times d_i \\ &= \sum_{i=1}^{NB} a_i^k \times (g_i^k)^2 + b_i^k \times g_i^k + c_i^k + \sum_{i=1}^{NB} \alpha \times (1 - \delta_i^k) \times d_i \end{aligned} \tag{13}$$

The OPF problem is defined as (14) subjecting to constraints (5) to (11) in order to determine the optimal active power of the generating units.

$$Min\ GC^k = Min\ F(g_i^k,\ \delta_i^k) \tag{14}$$
$$\begin{aligned} Min\ F(g_i^k,\ \delta_i^k) &= \sum_{i=1}^{NB} a_i^k (g_i^k)^2 + b_i^k g_i^k + c_i^k \\ &\quad + \alpha \times \sum_{i=1}^{NB} (1 - \delta_i^k) \times d_i \end{aligned} \tag{15}$$

$$\begin{aligned} \Rightarrow Min\ F(g_i^k,\ \delta_i^k) &= \sum_{i=1}^{NB} a_i^k (g_i^k)^2 + b_i^k g_i^k + c_i^k \\ &\quad - \alpha \times d_i \delta_i^k \end{aligned} \tag{16}$$

Defining $h_i = \alpha \times d_i$, yields:

$$\Rightarrow Min\ F(g_i^k,\ \delta_i^k) = \sum_{i=1}^{NB} a_i^k (g_i^k)^2 + b_i^k g_i^k + c_i^k - h_i \delta_i^k \tag{17}$$

In (17), term of $a_i^k (g_i^k)^2 + b_i^k g_i^k + c_i^k - h_i \delta_i^k$ can be approximated by a quadratic function of g_i^k and δ_i^k.

$$f_i(g_i^k,\ \delta_i^k) = \frac{1}{2} Q_{ii} (g_i^k)^2 + b_i^k g_i^k + h_i \delta_i^k + c_i^k \tag{18}$$
$$F(g_i^k,\ \delta_i^k) = \sum_{i=1}^{NB} f_i(g_i^k,\ \delta_i^k) = \mu + bP_G^T + \frac{1}{2} P_G^T Q P_G \tag{19}$$

where, μ is a scalar coefficient that is determined according to the cost coefficients (a_i^k, b_i^k, c_i^k) and parameter h_i. b is a row vector with the dimension of NB that describes the cost coefficients of the linear terms in (18), and Q is a symmetric matrix with the dimension of $NB \times NB$ including the coefficients of the quadratic terms. P_G is column vector with dimension of NB containing the decision variables g_i^k and δ_i^k.

A quadratic programming (QP) method based on DABC algorithm is used to minimize $F(g_i^k,\ \delta_i^k)$ which is subjected to the mentioned OPF constraints for each expansion plan.

The goal of the proposed problem is the determination of the number of new transmission lines needed for network expansion with minimum lines investment, substations expansion cost (from the voltage level point of view), active power losses, and generation costs. The proposed STEP is a mixed-integer non-linear optimization problem that is solved by DABC algorithm because of its high efficiency, flexibility, and simple implementation.

III. SOLUTION ALGORITHM

In the artificial bee colony (ABC), a possible solution is represented by the position of food sources and its fitness is described by the nectar amount of food sources. Therefore, the food source places form the problem search space. In the first step, initial food source positions are generated randomly as (20), considering parameters limits.

$$x_{ij} = x_j^{\min} + \omega \times (x_j^{\max} - x_j^{\min}), \quad i = 1, \ldots, SN,\ j = 1, \ldots, D \tag{20}$$

ω is a random number from 0 to 1. SN and D are the numbers of food sources and optimization parameters, respectively. After the generation of initial solutions (20), the employed, onlooker, and scout bees start to repetitively search among these solutions. The search process can be terminated by choosing a maximum number for search cycles or choosing an error tolerance.

Employed bees try to find new food sources in the neighborhood of initial solutions by some modification on the previous food source positions according to their qualities using (21).

$$v_{ij} = x_{ij} + \varphi_{ij}(x_{ij} - x_{kj})k = 1, \ldots, SN \tag{21}$$

j is a integer number generating randomly between 1 and D. k is a random real number in interval $[-1, 1]$ that does not include i and j. If value of a produced parameter is not in its permissible limits, an acceptable value is set for related parameter. In this work, the value of the parameter exceeding its boundary is set to its boundaries. After producing an acceptable value for x_i, its fitness is determined by (22).

$$fitness_i = \begin{cases} 1/(1+f_i) & if \ \ f_i \geq 0 \\ 1+|f_i| & if \ \ f_i \langle 0 \end{cases} \tag{22}$$

In (22), f_i is the cost function of the solution v_i. The algorithm selects better solution between x_i and v_i according to its fitness amount. If the fitness of food source at new position v_i is better than that of x_i, the employed bees memorize the v_i and forget the old position x_i. Otherwise the old position remains in bees' memory. The algorithm goes to the next trial if a better solution than x_i is found (v_i); otherwise the counter of the trial number is reset to 0. When the search of all employed bees is finished, their information about fitness amounts is shared. Then onlooker bees evaluate the fitness data provided by employed bees and select a solution with a probability based on its fitness. For this purpose, the roulette wheel selection procedure is used as follows:

$$p_i = \frac{fitness_i}{\sum_{i=1}^{SN} fitness_i} \tag{23}$$

In this process, a real number is generated randomly between 0 and 1 for each fitness. If the probability value (p_i) of associated fitness is greater than this random number, the onlooker bee modifies the position of the food source using (21).

When all searches are completed by employed and onlooker bees in a cycle, the algorithm checks exhausted sources for abandonment. For this purpose, if the value of the counter used during the search process is more than the control parameter of the ABC algorithm (limit), the food source associated with this counter is abandoned and replaced by a new source found randomly by the scout bees (the algorithm self-organization property). Assuming x_i is position of an abandoned source, a new random position is generated and is replaced with x_i. In ABC algorithm, only one food source can be exhausted in each cycle and just one employed bee can be assumed as a scout bee. In this regard, the solution related to the higher counter is chosen as the exhausted source if values of two or more than two counters exceed the "limit".

The proposed STEP is an optimization problem with discrete decision variables, while ABC is a metaheuristic algorithm that works based on real numbers. In this way, the algorithm cannot be applied to the proposed problem directly. Binary artificial bee colony (BABC) or discrete one (DABC) can be employed to solve this problem.

In the current work, the DABC algorithm is used because of its simplicity and higher convergence speed compared to BABC. In this method, a solution is represented by start and end bus IDs as well as number of new and initial line circuits of each corridor.

IDs of start and end buses are fixed during the iterative search process of the algorithm and only number of line circuits are changed. Therefore, position vector can include only number of line circuits without bus IDs. For instant, the position vector of an expansion plan for a transmission system with 12 corridors, in which each corridor has one initial (existing) line circuits, is shown in Fig. 1. This solution proposes one new line circuits for corridors 2, 6, 10, and 11, two new circuits for the first and the last corridors, three circuits for corridors 4 and 7, and finally no new circuits for corridors 3, 5, 8, and 9. Also, the numbers of circuits in each corridor are updated by new position vectors using (20).

$$X=(3, 2, 1, 4, 1, 2, 4, 1, 1, 2, 2, 3)$$

FIGURE 1. A typical position vector.

IV. SIMULATION RESULTS

The transmission network of Azerbaijan regional electric company was used to evaluate the efficiency of the proposed approach. This real transmission system is located in the northwest of Iran and is shown in Fig. 2. The network configuration, substation information, loads and generation data of the test system are listed in Tables 1 to 3. Also, lines characteristics and construction costs are given in Tables 4 to 6. Moreover, the cost coefficients of the power plants are listed in Table 7. The planning horizon and base power are 10 years and 100 MVA for all scenarios, respectively. All simulations are carried out in MATLAB software.

Availability of land for installation of new equipment such as new lines and transformers is an important issue that should be considered in the TEP problem. In this case, some corridors cannot be expanded or their maximum number of constructible lines is limited because of insufficient land. Also substations of some buses cannot include more new transformers due to unavailability of land. These issues have been considered in this real transmission network by setting maximum number of allowable lines and transformers to zero or 1 in some corridors and buses.

Power plants located on buses 1 and 5 are fueled by gas (type 1), those on buses 8 and 13 are fueled by gas and oil (type 2), and generating units on buses 10 and 15 are fueled by oil (type 3).

Also, the coefficient α and value of C_{MWh} are considered 2.8×10^3 \$/MW and 27.5 \$/MWh, respectively. The DABC approach was applied to the test system with 7% annual factor of load growth and 10% inflation rate for fuel price of all power plants and the results were provided in Tables 8 and 9 and Fig. 3.

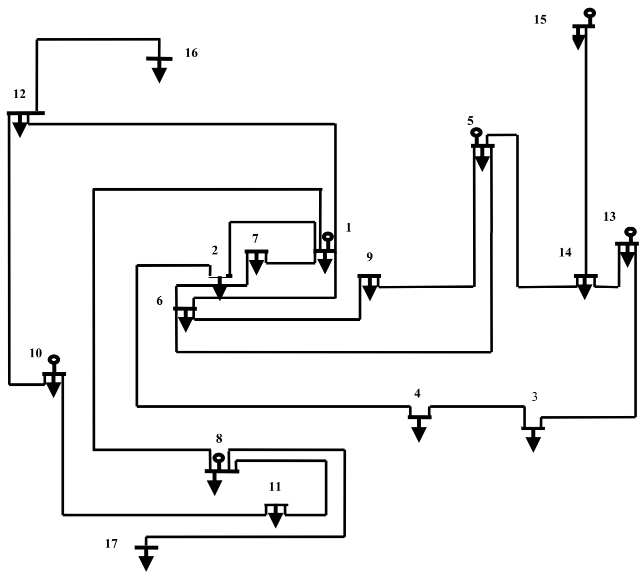

FIGURE 2. Modified network of the Azerbaijan regional electric company.

TABLE 1. Network configuration.

Corridor	Start Bus	End Bus	Corridor Length (km)	Voltage Level (kV)	Number of Circuits
5	1	6	55	230	1
1	1	2	14	230	2
73	6	9	18	230	1
18	2	4	83	230	1
67	5	14	110	230	1
84	8	11	65	230	2
99	10	11	125	230	2
121	14	15	139	230	1
11	1	12	122	400	1
62	5	9	100	230	1
59	5	6	103	230	2
41	3	13	105	400	1
32	3	4	81	230	1
117	13	14	44	230	2
100	10	12	134	230	2
7	1	8	75	230	2
71	6	7	33	230	1
6	1	7	22	230	1
90	8	17	71	400	1

TABLE 2. Substations information.

Substation	Voltage Level (kV)	Substation	Voltage Level (kV)
1	400/230	10	230/132
2	230/132	11	230/132
3	400/230	12	230/132
4	230/63	13	230/63
5	230/132	14	400/230
6	230/132	15	230/63
7	230/132	16	230/132
8	230/132	17	230/132
9	230/132	-	-

TABLE 3. Loads and generation data.

Bus	Load (MW)	Generation capacity (MW)	Bus	Load (MW)	Generation capacity (MW)
1	378	1250	10	134	290
2	202	0	11	125	0
3	42	0	12	256	0
4	53	0	13	78	720
5	45	1100	14	46	0
6	64	0	15	45	240
7	88	0	16	14	0
8	49	750	17	79	0
9	70	0	-	-	-

TABLE 4. Lines characteristics.

Voltage level (kV)	Maximum Loading (MVA)	Reactance (p.u./km)	Resistance (p.u./km)
230	397	3.85e-4	1.22e-4
400	750	1.24e-4	2.44e-4

TABLE 5. Construction costs of 230 kV lines.

Number of Line Circuits	Fix Construction Cost (US dollars)	Variable Construction Cost (US dollars)
1	546500	45900
2	546500	63400

TABLE 6. Construction cost of 400 kV lines.

Number of Line circuits	Fix Cost Construction (US dollars)	Variable Construction Cost (US dollars)
1	1748600	92900
2	1748600	120200

TABLE 7. Cost coefficients of power plants.

Capacity (MW)	1250	1100	750	290	720	240
a (10^3\$/MW^2)	0.4	0.37	0.3	0.5	0.36	0.25
b (\$/MW)	13.3	14.1	15.8	22.5	15	16.6
c (\$)	0	0	0	0	0	0

Tables 8 and 9 describe the expansion and operation costs and the optimal expansion plan, respectively, when the same inflation rate is considered for all different types of power plants (base case). Also, Fig. 3 shows the optimal generation for different types of power plants.

The power plant located on bus 10 has no output and the generation of bus 15 which includes a power plant of type 3 is a fraction of its maximum power generation. In order to consider the uncertainty in fuel price and future load expansion, the proposed idea is tested on this network in four scenarios. In scenario 1, the annual load growth factor is 7% (LGF^1 =0.07) and inflation rate of the fuel price is

TABLE 8. Proposed transmission expansion plan for base case.

Corridor	Start Bus	End Bus	Number of New Circuits	Line Voltage (kV)
5	1	6	1	230
6	1	7	1	230
8	1	9	2	400
9	1	10	2	400
19	2	5	2	400
46	4	5	1	400
60	5	7	2	230
64	5	11	2	400
65	5	12	2	400
69	5	16	1	230
73	6	9	1	230
79	6	15	2	230
83	8	10	2	400
90	8	17	1	400
94	9	13	2	400

TABLE 9. Costs of the network expansion, losses, and loss of load for base case (million US$).

Lines Expansion Cost	153.4
Substations Expansion Cost	54.3
Losses Cost	183.46
Loss of Load Cost (LOLC)	0
Total Cost	391.19

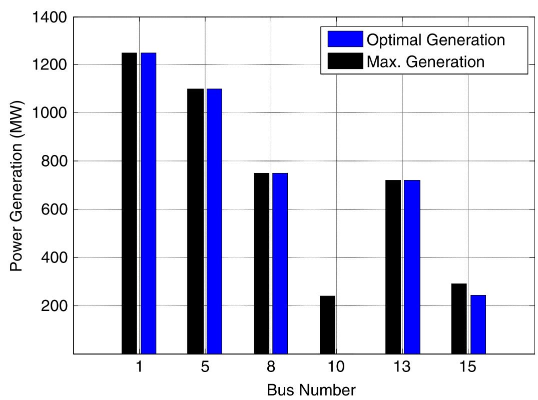

FIGURE 3. Optimal power generation compared to maximum generation in the base case.

considered 10% for power plants of types 2 and 3, while this amount is increased to 15% for type 1. In the same way, in scenarios 2 and 3, load growth factors are set to 7% and the inflation rates are increased and decreased for power plants of types 2 and 3, respectively, while these amounts for another type is considered 10%. Finally, in scenario 4, load growth factor is increased by 3% (LGF^4 =0.10), while the inflation rates of fuel price are the same as scenario 3. It should be noted that DABC algorithm was executed for 30 independent runs and the best results were selected as final solutions in each scenario.

A. SCENARIO 1

In this scenario, the load growth factor is 7% and the inflation rate of fuel price for power plants of types 2 and 3 is considered 10%, while that of type 1 is 15%. The DABC approach is applied to solve the proposed STEP problem and the optimal expansion plan as well as the expansion, losses, and LOL costs are given in Tables 10 and 11. Also, Fig. 4 shows the optimal power generated by different types of power plants.

TABLE 10. Proposed transmission expansion plan in scenario 1.

Corridor	Start Bus	End Bus	Number of New Circuits	Line Voltage (kV)
6	1	7	1	400
8	1	9	2	400
19	2	5	2	400
46	4	5	2	400
52	4	11	1	400
60	5	7	2	400
63	5	10	2	400
64	5	11	2	400
65	5	12	2	400
68	5	15	1	400
69	5	16	1	230
73	6	9	1	230
83	8	10	2	400
90	8	17	1	400
94	9	13	2	400

TABLE 11. Costs of the network expansion, losses, and loss of load in scenario 1 (Million US$).

Lines Expansion Cost	166.75
Substations Expansion Cost	62.16
Losses Cost	166.05
LOLC	0
Total Cost	394.96

By comparing Fig. 3 with Fig. 4, it can be seen that the optimal generations of power plants on buses 5 and 15 are decreased and increased, respectively. The reason is that the power plant generation of bus 5 is more costly than its base case because of an increase in the inflation rate of fuel price. Therefore, the generation deficiency is compensated by increasing the generation of the cheaper power plant on bus 15, in which its power output is below its maximum capacity. Nevertheless, the optimal generation of power plant 1 remains unchanged, while its power generation is cheaper than power plant generation of bus 5.

From Tables 8 and 11, it can be observed that with an increase in fuel price inflation rate of power plants of type 1, more 400 kV lines are constructed compared to 230 kV ones.

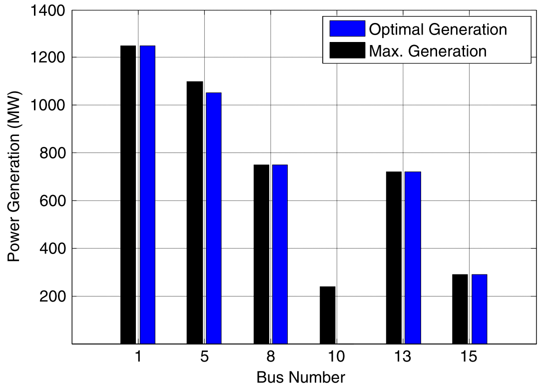

FIGURE 4. Optimal and maximum power generation in scenario 1.

Also, regarding Tables 9 and 10, it is found out that the expansion cost of lines and substations (costs of transformers and other accessories in substations) are increased but the network losses cost is decreased. This fact shows that by increasing and reducing the generation level of cheap and expensive generating units, respectively, the proposed algorithm compensates the increment of operational costs by the expansion of more 400 kV lines. Since the power losses of 400 kV lines is lower than that of 230 kV ones. For the expansion of 400 kV lines, expansion of substations from voltage level point of view is needed.

In simple terms, it can be said that increase in gas price affects transmission expansion decisions by encouraging planners to propose construction of more 400 kV lines in order to reduce the losses cost against increase in generation costs. Although construction of more 400 kV lines causes the lines and substation expansion costs are increased, total costs are not increased significantly compared to the base case, because the main part of generation and expansion costs are compensated by reducing power losses and unit commitment of cheaper power plants.

B. SCENARIO 2

Here, the load growth factor is 7% (LGF^{2} =0.07) and inflation rate of fuel price for power plants of types 1 and 3 is considered to be the same value of the base case (10%), while the inflation rate for power plants of type 2 is considered 15%. After applying the DABC method to solve the proposed problem, the obtained results are shown in Tables 12 and 13 and Fig. 5.

Similar to the previous scenario, it is seen that costly generation of power plant of type 2 leads to decrease in power plant generation of bus 8 and increase in optimal generation of power plants of type 3 on buses 10 and 15.

By comparing Table 12 with Tables 8 and 10, it is obvious that the proposed plan for transmission system expansion has been changed, in which the number of new 400 kV lines compared to 230 kV ones have been increased and decreased in comparison with the base case (Table 8) and scenario 1, respectively. Moreover, the number of new lines proposed

TABLE 12. Proposed transmission expansion plan in scenario 2.

Corridor	Start Bus	End Bus	Number of New Circuits	Line Voltage (kV)
5	1	6	1	230
6	1	7	1	230
8	1	9	2	400
19	2	5	2	400
21	2	7	2	400
29	2	15	2	400
41	3	13	1	230
46	4	5	1	230
52	4	11	1	400
60	5	7	2	230
64	5	11	2	400
65	5	12	2	400
69	5	16	2	230
77	6	13	2	230
90	8	17	1	400
103	10	15	2	400
107	11	13	2	400

TABLE 13. Costs of the network expansion, losses, and loss of load in scenario 2 (Million US$).

Lines Expansion Cost	166.25
Substations Expansion Cost	43.33
Losses Cost	148.9
LOLC	0
Total Cost	358.48

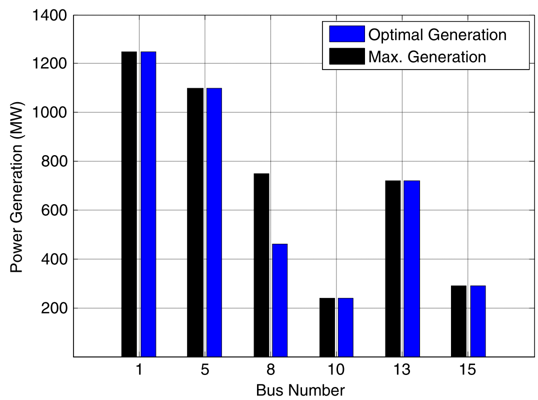

FIGURE 5. Optimal and maximum power generation in scenario 2.

for construction between bus 8 and other buses is decreased to one line, where optimal generation on this bus has been reduced. In contrast, the voltage of the line connected to bus 15, a bus with an increase in its optimal generation, has been upgraded from two 230 kV line circuits in corridor 79 to two 400 kV line circuits in corridor 103.

According to Tables 13 and 10, although the number of 400 kV lines to 230 kV lines in the expansion plan of scenario 2 is less than that of scenario 1, but its losses cost and total expansion cost is lower than one is proposed in the first scenario. Also, it is seen that the costs of lines and substations expansion are increased, while the network losses cost is decreased. Therefore, it can be said that the total cost of network is reduced by more efficiently operation of power plants.

In other words, similar to scenario 1, it can be seen that increase in gas and oil prices changes transmission expansion plan by suggesting construction of more 400 kV lines for power loss reduction in order to compensate increase in electricity generation costs because of fuel price increment. The main difference of this scenario with previous one is that not only costly power generation due to increase in gas and oil prices are compensated, but total cost is reduced compared to the base case because of unit commitment of cheaper power plants. Although, losses cost has not been reduced as much as scenario 1, increment of gas and oil inflation rate causes cheaper units are operated with their maximum capacity beside utilization of transmission lines with less power losses (400 kV lines).

C. SCENARIO 3

To evaluate the effects of decrease in fuel price inflation rate on transmission expansion planning, the inflation rate of the fuel price is assumed 10% for power plants of types 1 and 2 and 5% for others. The results are listed in Tables 14 and 15 and shown in Fig. 6.

TABLE 14. Proposed transmission expansion plan in scenario 3.

Corridor	Start Bus	End Bus	Number of New Circuits	Line Voltage (kV)
6	1	7	1	230
8	1	9	2	400
9	1	10	1	400
19	2	5	2	400
21	2	7	1	230
46	4	5	1	400
60	5	7	2	230
64	5	11	2	400
65	5	12	2	400
69	5	16	1	230
79	6	15	1	400
90	8	17	1	400
107	11	13	2	400

Figure 6 shows that the generation arrangement proposed in the present scenario is exactly similar to that of scenario 2. Thus, the decrease in the inflation rate of fuel price for power plants of type 3 behaves like increasing this value for power plants of type 2. Even though the losses cost for the proposed expansion plan of scenario 3 is less than that of scenario 2, but regarding Table 14, it is clear that the proposed DABC algorithm suggests configurations with more 400 kV lines. The fact shows that although the method of changing inflation rate amount for fuel price may not affect the generation arrangement but it has an important role in the determination of network lines configuration.

TABLE 15. Costs of the network expansion, losses, and loss of load in scenario 3 (Million US$).

Lines Expansion Cost	142.66
Substations Expansion Cost	48.16
Losses Cost	161.58
LOLC	0
Total Cost	352.4

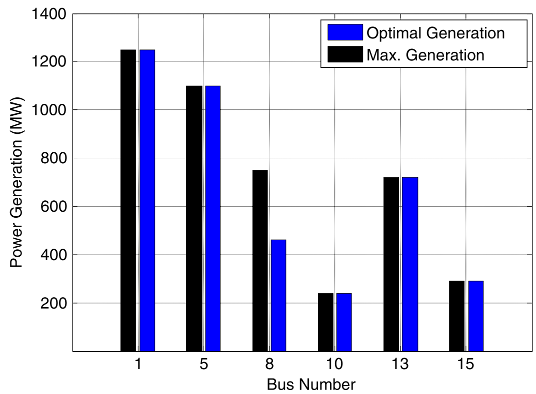

FIGURE 6. Optimal and maximum power generation in scenario 3.

D. SCENARIO 4

In order to show the effects of power demand increase on transmission expansion planning, load growth factor (LGF^4) is set to 10% and the inflation rates of the fuel price are similar to scenario 3. Tables 16 and 17, as well as Fig. 7 show the numerical results.

Comparing Table 16 with Table 14 indicates that more 400 kV lines are proposed for expansion of transmission network by increasing 3% in load growth factor. This fact causes the expansion costs of lines and substations are increased considerably (please see Table 17). Also, expansion of load growth factor leads to a significant increase in losses cost and subsequent total cost of network because of lines power flow increment. This fact shows important role of load growth uncertainty and expansion in TEP models.

In comparison with Fig. 6, Fig. 7 heights this important point that all power plants should be operated in their maximum generation level in order to meet the expanded load growth. For this reason, power plants fuelled by gas and oil on bus 8 that had already generated powers lower than their capacities in previous scenario should increase their power generation to maximum level. Therefore it can be seen that future load expansion affects both generation and transmission plans and therefore should be considered beside inflation rate of fuel price in TEP problem.

Finally, it can be concluded that fuel price has an important effect on the configuration of network lines and the total cost of the network. Accordingly, considering uncertainty in fuel price causes the STEP problem to be solved more accurately. In order to verify the accuracy of the proposed approach,

TABLE 16. Proposed transmission expansion plan in scenario 4.

Corridor	Start Bus	End Bus	Number of New Circuits	Line Voltage (kV)
5	1	6	2	400
6	1	7	2	400
8	1	9	2	400
10	1	11	1	230
11	1	12	2	230
15	1	16	2	400
16	1	17	2	400
19	2	5	1	400
34	3	5	2	400
46	4	5	2	400
51	4	10	2	400
64	5	11	2	400
65	5	12	2	400
71	6	7	1	230
86	7	12	1	400
89	7	15	2	400
90	8	17	1	400
107	11	13	2	400
94	9	13	1	400

TABLE 17. Costs of the network expansion, losses, and loss of load in scenario 4 (Million US$).

Lines Expansion Cost	266.5
Substations Expansion Cost	54.2
Losses Cost	520.6
LOLC	0
Total Cost	841.3

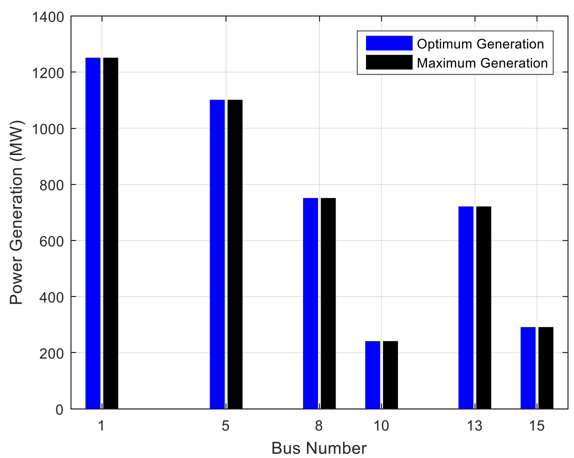

FIGURE 7. Optimal and maximum power generation in scenario 4.

the proposed expansion planning problem was solved by DPSO [2] and DCGA [7] in addition to DABC and convergence process of three methods for all scenarios are shown in Figs 8 to 10.

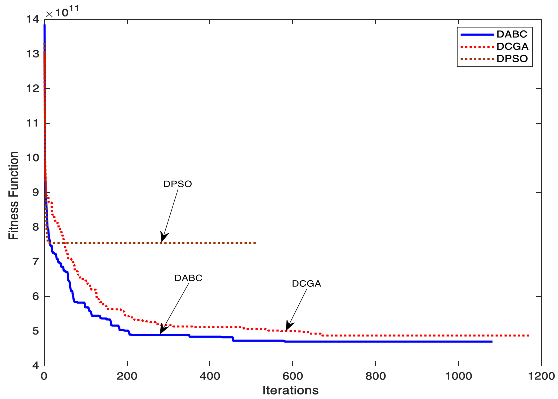

FIGURE 8. Performance of DABC compared to DPSO and DCGA in scenario 1.

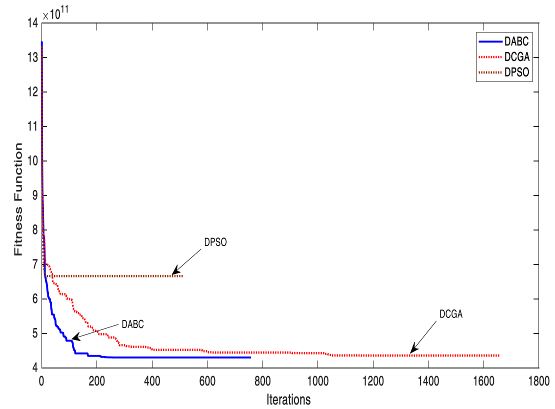

FIGURE 9. Performance of DABC compared to DPSO and DCGA in scenario 2.

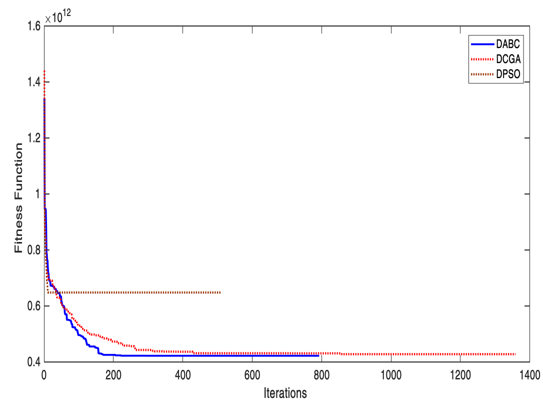

FIGURE 10. Performance of DABC compared to DPSO and DCGA in scenario 3.

From Figs 8 to 10, it can be seen that the DABC have better performance than DPSO and DCGA because it approached better fitness functions by helping the algorithm to escape from local optima, while DPSO and DCGA fall in local minima. It means that searching process of DABC is more effective than of DPSO and DCGA. In other terms, DABC could find more optimal values for objective function (1) compared to DPSO and DCGA. This issue confirms that the

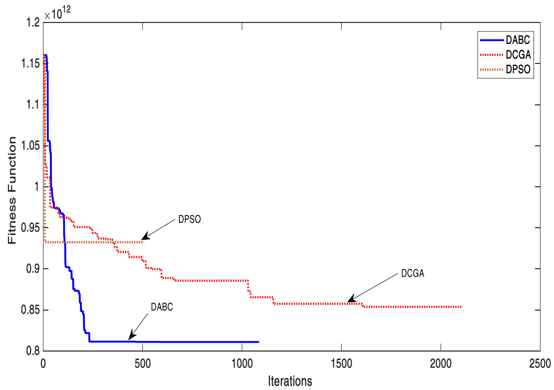

FIGURE 11. Performance of DABC compared to DPSO and DCGA in scenario 4.

solutions found by the proposed algorithm are completely more optimal that those found by DPSO and DCGA methods.

V. CONCLUSION

In this paper, transmission network expansion planning considering power losses, substations expansion based on their voltages and uncertainty in fuel price and power demand expansion is studied using a DABC and QP based method. The results evaluation shows that the inflation rate of fuel price for different types of power plants and load growth factor have important effects on the network configuration. These parameters by changing generation and or substation arrangements from voltage level point of view or network losses amount can affect the proposed transmission expansion plans. Thus considering the uncertainty in fuel price and demand causes the expansion cost of lines and substations, losses cost and therefore the total cost of the network are calculated more precisely and subsequent STEP problem is solved more accurately. In simple terms, considering the effect of fuel price and load uncertainties in TEP causes more exactly calculation of the expansion and operation costs of the network. Also, it is concluded that any change in fuel price that causes a decrease in the generation of large power plants (high-capacity power plants) leads to more expensive expansion plans for the transmission network. Vice versa, any change that causes an increase in the generation of small power plants (low-capacity ones) or a decrease in that of medium-size ones (medium-capacity power plants) leads to less expensive transmission expansion plans. Moreover, it can be said that DABC can solve the proposed transmission network expansion planning problem more efficiently than DPSO and DCGA, because it finds more accurate solutions for the proposed problem when compared to DPSO and DCGA methods.

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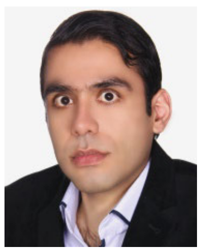

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