An online method for MILP co-planning model of large-scale transmission expansion planning and energy storage systems considering N-1 criterion

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Abstract

In recent years, increased integration of renewable energy sources (RES) calls for extensive and costly investments in transmission networks. In response, power system decision-makers try to apply alternative solutions aimed to decrease the imposed investment costs. In this context, the presence of large-scale energy storage systems (ESSs) in transmission network can be a practical option for deferring investment in expansion plans of transmission lines, alleviating system congestions, and attaining higher flexibility. In this paper, an efficient model is proposed for co-planning expansion studies of compressed air energy storage (CAES) units and transmission networks. The associated optimisation formulation of co-planning problem is expressed as a MILP model, which can be efficiently solved. The proposed model is applied on the Garver as well as RTS test systems and N-1 criterion is considered to address the system reliability performance in expansion studies. The results demonstrate that the proposed co-planning framework has a superior performance in expansion plans of transmission systems.

1 | INTRODUCTION

Transmission expansion planning (TEP) is conventionally tasked to determine the optimal structure of the transmission network based on the forecasted load growth and generation expansion plans for a given time interval in the future [1–3]. Widespread integration of renewable energy sources (RES) in recent years and the arrival of major uncertainties in the grid have called for vast investments to construct new transmission lines for reliable delivery of electricity to the end consumers and load centres. Environmental concerns, the increase in electricity demand portfolios, and reduction of available fossil fuel resources on one hand, and maximum utilisation of RES on the other, have posed many technical and economic challenges to secure and efficient operation of the bulk power grids. Solutions offering economic, flexible, and reliable options are needed in response to capture the RES uncertainties in modern power systems [4–6].

Power system planners investigate various flexible investment plans to address the aforementioned challenges. Flexible investment plans can defer TEP investment projects; furthermore, they can alleviate power system congestion and enhance the grid capacity and flexibility in dealing with intermittent RES. Flexible investment plans can be broadly categorised to demand-side management programs and utilisation of energy storage systems (ESSs) [7]. Primarily focused on power distribution grids, implementation of demand-side management programs is one effective mechanism to capture the RES intermittency, which needs extensive investments otherwise. In transmission sector, however, widespread deployment of ESSs can address the challenging requirements for huge transmission lines construction (high investment costs, long time periods of installation etc.) and smoothen the consumption profile by charging during off-peak periods and discharging during peak demand intervals [8]. Furthermore, ESSs are promising solutions for massive integration of RESs, enabling an effective mechanism to capture the...
Pumped hydro energy storage (PHES) and compressed air energy storage (CAES) are the most promising technologies of large-scale storage facilities, which are utilised at the transmission level. Comparing the two technologies, CAES is economically more attractive than PHES in lower capacity conditions as it relaxes the geographical constraints [9]. Although CAES technology requires a natural reservoir and results in environmental pollutions, the CAES advantages include fast response, energy storage for a long time, low losses, and low heat generation during operation, to name a few. Finally, CAESs have demonstrated promising efficiency in systems with gas turbines [9]. Hence, although the proposed framework is generic where RESs can also be modelled by adding the related terms in the power flow equation, this paper particularly focuses on the deployment of CAESs and the corresponding expansion plans coordinated with the TEP. In order to consider RES penetration in power grids, other types of ESSs are more commonly approached that can be studied in the future research.

The TEP is a complex large-scale optimisation problem, for which many researchers have tried to introduce efficient solution algorithms. In [10], a model for TEP problem with the main objective to minimise the investment, operation, and reliability costs using Genetic algorithm is introduced. In [11], four formulations are presented for TEP problem including D.C. model, transportation model, hybrid model, and disjunctive model. Reference [12] proposes a linear multi-objective approach for optimal reactive power dispatch in wind-integrated transmission networks. In [13], a novel multi-stage AC-OPF framework is suggested considering the network ability to manage high electricity demand and low RES. Reference [14] presents a joint power generation expansion and TEP problem operated in an integrated and restructured electricity and gas market. In [15], [16], mixed-integer AC power flow formulations are presented to solve TEP problem to control the active and reactive power flow and the power losses in the network and find a global optimal solution, respectively. Reference [17] presents a cost-oriented dynamic clustering method for the stochastic TEP model considering massive number of scenarios using the Benders decomposition approach and multiple parametric linear programming. In [18], a linear model for two-stage adaptive robust transmission expansion planning (AR-TEP) is presented by linear decision rules (LDRs), where the AR-TEP model is directly solved; therefore, this model does not need a decomposition approach.

On the other hand, some researchers have progressively tried to introduce models for deployment of ESS technologies in TEP studies. In this vein, authors in [19] investigate the impacts of ESSs on TEP problem through a non-linear optimisation model decomposed to investment and operation sub-problems. In [7], utilisation of flexible system technologies such as phase-shifting transformers, ESSs, and demand-side management programs are incorporated in a long-term stochastic planning formulation. A MILP model is presented for TEP considering flexible technologies, which is solved by Benders decomposition scheme. In [20], a stochastic multi-stage co-planning model of TEP incorporating battery energy storage systems (BESS) is presented to capture uncertainties in RES and load growth. Finally, the research in [21] aims to present an adaptive robust optimisation framework for coordination of TEP and ESSs, which consider both long-term and short-term uncertainties. In detail, this stochastic model is solved by Benders algorithm to minimise the investment costs.

Investigating the streams of literature, non-linear and linear optimisation models can be applied on a general TEP problem that incorporates ESS technologies. The former is commonly solved through heuristic algorithms, while the latter is solved via iterative approaches such as branch-and-bound (B&B) algorithms. In addition, some references have presented new TEP structures without considering ESSs. For instance, in [22], [23], stochastic TEP problems are presented to achieve a transmission plan for a target year considering probability density functions of system uncertainties (load and wind) and minimise the investment and reliability costs under contingency scenarios. Reference [24] presents a new approach on static TEP problem to minimise the cost deviation from the initial point, where the authors consider different types of transmission line designs and reliability analysis by a heuristic algorithm. In [25], an iterative stochastic TEP optimisation problem is presented with contingency analysis which iteratively adds important lines to reduce the computation time, but the direct solution for contingency analysis was not included. Finally, although a stochastic multi-objective optimisation TEP problem is presented in [26] to minimise the investment, operation, and expected load shedding costs considering N-1 contingency, ESSs were not considered.

As a result, motivated by the above, to cover the above-mentioned research gaps, this paper investigates how simultaneous expansion of ESSs and transmission lines (ES-TEP) can help power grid decision-makers to more optimally operate the power grid of the future integrated with modern infrastructure. A linear optimisation model is mathematically presented that guarantees practicality of the expansion plans. Finally, the main contributions of this paper are as follows:

(i) A general mixed-integer linear programming (MILP) TEP model is presented considering compressed air energy storage (CAES) systems.
(ii) An efficient solution method is developed based on a linearisation approach that relaxes the need to use decomposition techniques.
(iii) A new online method is introduced to incorporate the N-1 reliability criterion in the ES-TEP problem.
(iv) An investigation of the trade-offs between investments in TEP or CAESs is presented.

The remainder of this paper is organised as follows. In Section 2, the proposed model for ES-TEP problem including the non-linear ES-TEP formulations, linearisation method, and linearised model of ES-TEP problem are presented. The Garver
test system data and case study results are presented in Section 3, while sensitivity analyses of this test system are discussed in Section 4. To consider a large-scale case study, the RTS test system data and case study results are supposed to be in Section 5. Finally, concluding remarks are presented in Section 6.

2 | PROPOSED ALGORITHM AND FORMULATION

The objective of the proposed ES-TEP planning problem is to minimise (i) the total operation costs, (ii) the investment costs required for construction of new transmission lines and deployment of ESS units, and (iii) load curtailment cost. We, first, introduce the non-linear ES-TEP formulations. Then, a novel linearisation method is introduced to transform the problem into a mixed integer programming (MIP) model that can be solved by off-the-shelf linear programming packages. Therefore, candidate solutions including new transmission lines and CAES units are considered in solving an MILP problem taking into account the power balance constraints as well as those for CAES units, natural gas, and O&M costs. Finally, a practical approach is pursued to investigate the ability of the network in satisfying the power balance and CAESs requirements under contingencies. In this view, load curtailment cost is computed in CAESs discharging modes in order to securely satisfy the contingency conditions.

It is assumed that the system operation cost in a year can be represented by two samples of summer and winter days. Also, in this paper, the maximum number of candidate transmission lines in each corridor and the maximum number of candidate CAES units at each bus are assumed to be two and one, respectively. Therefore, one parameter is introduced to define available (online) transmission lines; also, two variables are defined for installed transmission lines. In order to accurately model the restoration time of the interrupted transmission lines, the proposed algorithm is repeated in 24 hourly periods in each day. Because of the fact that the outage instant and duration for each transmission line is random and cannot be predicted by power system planners. Therefore, the proposed algorithm models the N-1 criterion in each time during the 24 h of a day. In this paper, the repair time of the interrupted transmission lines is assumed to be 10 h. The structure of these periods is presented in Table 1.

Decision variables in the proposed optimisation problem include new installed transmission lines and CAES units which are introduced as binary variables, while CAESs charging/discharging power, generated power of system generating units, and load curtailments during contingencies are continuous variables. Since a linearisation approach is pursued to transform the proposed MILP model, the installed transmission line variables are presented as binary variables. The state variables including CAESs status are introduced as binary variables, while transmission line power flows, voltage phase angles, and CAESs states of charge are considered continuous variables. The model constraints include transmission line flow limits, variables limit, supply–demand balance, and those associated with the CAESs status and their states of charge.

2.1 | Non-linear ES-TEP formulation

The proposed objective function for the ES-TEP problem (1) includes the investment, operation and O&M costs of the installed transmission lines and CAES units. In this regard, the costs corresponding to the new installed transmission lines and CAESs are presented in (2) and (3), respectively. Moreover, the net operation cost (4) includes generating units cost, cost of purchasing natural gas and cost of CAESs’ net electricity consumption from the market. The second and third terms in (4) are the specific terms related to the CAESs’ characteristics, different from other types of ESSs. That is, the mentioned specific terms for CAESs are not needed in BESS if they are to be deployed. Hence, with minimum adjustments in the structure of the CAESs specific formulations, it is possible to accommodate other types of ESSs in the presented model. Note that the heat rate expresses the amount of fuel burned per unit of peak electricity generated by the expander [27]. Moreover, the O&M cost is presented in (5) includes the corresponding fixed and variable costs. Finally, investments plans are made at the beginning of the planning horizon, and it is assumed that the operation costs remain fixed throughout the planning horizon. Hence, its present worth is calculated using the discount factor expressed in (6).

\[
\text{Minimize } \left\{ \sum_{i,f} \left[ c_{pf}^{f} + c_{CS}^{d} + c_{sp}^{d} + c_{OM}^{d} \right] \right\}
\]

\[
\text{cost}_{pf}^{f} = \sum_{i \in I} \left[ y_{i}^{f} \times \left( g_{i}^{f} + g_{i}^{r} \right) \right],
\]

\[
\text{cost}_{CS}^{d} = \sum_{i \in I} \left[ c_{d}^{CS} \times p_{CS}^{d} + c_{E}^{CS} \times E_{CS}^{d} \right],
\]

\[
\text{cost}_{sp}^{d} = \sum_{d} \left[ y(d) \times \sum_{i \in I} \sum_{f} \left( \left( \delta_{i}^{f} + \delta_{i}^{r} \right) + HR \times c_{d}^{CS} \right) \right],
\]

\[
\text{HR} \times c_{d}^{CS} \times \left( p_{d}^{bf} - p_{d}^{df} \right)
\]
Linearisation method

One can see in the above formulations that constraints (8) and (12) are nonlinear, resulting in a mixed-integer non-linear programming (MINLP) optimisation model for ES-TEP problem. Hence, we pursue applying an efficient method to convert this nonlinear model to a linear one, which can significantly reduce the computational burden of this large-scale optimisation problem, while guaranteeing the optimality. In this paper, a Big-M centralised approach is presented to linearise (8) [30–33]. In addition, a novel algorithm is proposed to linearise (12). The linearised constraints (7)–(9) are presented in (16)–(19). Note that M is a big constant that is set to ten times of transmission lines capacities [34].

\[
\text{Subject to:}
\]

\[
\sum_{t \in T} \left( \alpha^f_{t,j} \times f_{t,j} + \Gamma^f_{t,j} \right) + G^f_{t,j} = D^f_{t,j} + P_{\text{dch}}^f_{t,j} - P_{\text{dch}}^f_{t,j}; \forall t, i,
\]

\[
f_{t,j}^f = \left( n^f_{t,j} + n^f_{t,j} + n^f_{t,j} \right) \times \Delta \theta_{t,j}^f \times \mu_p; \forall t, i,
\]

\[
\left| f_{t,j}^f \right| \leq f_j \times \left( n^f_{t,j} + n^f_{t,j} + n^f_{t,j} \right); \forall t, i,
\]

\[
G^f_{t,j} \leq G_{t,j}^f \leq G^f_{t,j}; \forall t, i,
\]

\[
0 \leq P_{\text{dch}}^f_{t,j} \leq \left( P_{\text{inj}}^f \times \chi^f_{t,j} \times U_{t,j}^f \right); \forall t, i,
\]

\[
S_{\text{dch}}^f_{t,j} = S_{\text{dch}}^f_{t-j-1} + P_{\text{dch}}^f_{t,j} - \left( \mu_p \times P_{\text{dch}}^f_{t,j} \right); \forall t, i,
\]

\[
0 \leq S_{\text{dch}}^f_{t,j} \leq \left( \chi^f_{t,j} \times S_{\text{dch}}^f \right); \forall t, i,
\]

\[
S_{\text{dch}}^f_{t} = P_{\text{dch}}^f - \left( \mu_p \times P_{\text{dch}}^f \right), \forall t, i;
\]

\[
\Delta f_{\text{dch}}^f = \chi^f_{t,j} \times U_{t,j}^f; \forall t, i.
\]

2.2 Linearisation method

According to the TEP constraints, the power balance of the generation, load, and CAESs charging/discharging power is ensured in (7), while D.C. power flow for online and installed transmission lines, line power flow limits, and power generation limits are modelled in (8)–(10). It should be noted that one of the important advantages of the DC power flow formulation in TEP studies is the acceptable computational efficiency it offers compared to the computationally expensive AC power flow models. Moreover, because AC power flow should be optimally converged to have an acceptable voltage profile during normal as well as contingency conditions, the power system planners do not have any anxiety about mentioned problems in DC power flow [28], [29]. According to the CAESs constraints, the hourly status of CAESs is specified in (11). Also, constraint (12) limits CAESs charging/discharging power, while CAESs state of charge per hour, CAESs state of charge limit, and the initial as well as final CAESs state of charge are specified in (13)–(15).
Linearised ES-TEP model—Normal operating state

The power balance of generation, load, and CAESs charging/discharging power is enforced in (16). Moreover, linear formulation of D.C. power flow for online as well as installed transmission lines, transmission line power flow limits, and power generation limits linearised by Big-M approach are specified in (10), (17–19). According to the CAESs constraints, the hourly CAESs status is presented in (11). Moreover, presence or absence of CAESs at different buses, linear relationship between the new and old variables, and CAESs charging/discharging power limits are modelled in (21–25). Finally, CAESs state of charge per hour, CAESs state of charge limit, and the initial as well as final CAESs state of charge are presented in (13–15). It should be noted that final CAESs state of charge at the end of each day, which is the initial CAESs state of charge at the next day, is considered to be zero. All the linearised constraints under normal operating conditions are as follows:

\[ s.t.: (10) - (11), (13) - (19), (21) - (25). \]

2.5 Linearised ES-TEP model—Contingency operating state

In order to model the N-1 contingency condition, two groups of matrices are introduced. In Step 1, we introduce three new square matrix named \( N^F \). Three matrices are based on three variables of online and installed transmission lines according to \( \Gamma \in \{ \Gamma^{o}, \Gamma^{s1}, \Gamma^{s2} \} \). In order to form the \( N^F \) matrices, the three variables are analogously placed on the columns. Note that the matrices are square owing to the fact that the number of N-1 contingencies is equal to the number of transmission lines. With \( N^F \) matrices built, a novel approach is proposed in Step 2 to form matrices \( K^F \) for contingencies. In doing so, the main diagonal of \( N^F \) are set to zero. With this in mind, the N-1 contingencies are introduced by \( K^F \) matrices; in other words, each column in \( K^F \) matrices represents an N-1 contingency. Thus, there are three matrices, each of which represent contingencies related to each variable in set \( \Gamma \in \{ \Gamma^{o}, \Gamma^{s1}, \Gamma^{s2} \} \). These matrices are generated in (28).

\[ N^F \rightarrow K^F = \begin{bmatrix} 0 & \ldots & n_1^F \\ n_0^F & \ldots & n_2^F \\ \vdots & \ldots & \vdots \\ n_0^F & \ldots & 0 \end{bmatrix}, \]

\[ \forall i, c, \Gamma \in \{ \Gamma^{o}, \Gamma^{s1}, \Gamma^{s2} \}. \]
\[
f_{\Gamma_t,c,l}^{\text{inf}} (p) = \eta_t^{\text{inf}} \times \Delta \theta_{\Gamma_t,c,l}^{\text{inf}} (p) \times su \varphi_i; \forall t, c, l, \Gamma^a \in \{\Gamma^{a1^*}, \Gamma^{a2^*}\},
\]

\[
\left| f_{\Gamma_t,c,l}^{\text{inf}} (p) - \left( su \varphi_i \times \Delta \theta_{\Gamma_t,c,l}^{\text{inf}} (p) \right) \right| \leq M \times \left( 1 - \eta_t^{\text{inf}} \right) ; \forall t, c, l,
\]

\[
\left\{ \Gamma^a \in \{\Gamma^{a1}\}, \Gamma^+ \in \{\Gamma^{a1^*}\} \right\} \land \left\{ \Gamma^a \in \{\Gamma^{a2}\}, \Gamma^+ \in \{\Gamma^{a2^*}\} \right\}.
\]

\[
\left| f_{\Gamma_t,c,l}^{\text{inf}} (p) - \left( su \varphi_i \times \Delta \theta_{\Gamma_t,c,l}^{\text{inf}} (p) \right) \right| \leq M \times \left( 1 - \eta_t^{\text{inf}} \right) ; \forall t, c, l,
\]

\[
\left\{ \Gamma^a \in \{\Gamma^{a1}\}, \Gamma^+ \in \{\Gamma^{a1^*}\} \right\} \land \left\{ \Gamma^a \in \{\Gamma^{a2}\}, \Gamma^+ \in \{\Gamma^{a2^*}\} \right\}.
\]

\[
G_t \leq G_{\text{inf}}^{\Gamma_t,c,l} (p) = \overline{G_t}; \forall t, c, l, \Gamma^+ \in \{\Gamma^{a0^*}, \Gamma^{a1^*}, \Gamma^{a2^*}\}. \tag{37}
\]

Analogously to (11), (13)–(15), (21)–(25), constraints (38)–(44) present CAESs operating equations under contingency. In (38), presence or absence of CAESs at buses under contingency is formulated. The CAESs status in discharging state per hour, linear relationship between new and old variables, and CAESs discharging power limit under contingency are provided in (39)–(41). The CAESs charge state per hour, CAESs state of charge limit, and initial as well as final CAESs state of charge under contingency are presented in (42)–(44). Finally, load curtailment limits at each bus under contingency are introduced in (45).

\[
\lambda_i \leq U_{\text{inf}}^{\text{inf}} (p) \leq \lambda_i; \forall t, c, l, \Gamma^+ \in \{\Gamma^{a0^*}, \Gamma^{a1^*}, \Gamma^{a2^*}\}, \tag{38}
\]

\[
U_{\text{inf}}^{\text{inf}} (p) \leq 1; \forall t, c, l, \Gamma^+ \in \{\Gamma^{a0^*}, \Gamma^{a1^*}, \Gamma^{a2^*}\}, \tag{39}
\]

\[
\lambda_{\text{inf}}^{\text{inf}} (p) \leq \delta_{\text{inf}}^{\text{inf}} (p) \leq \lambda_{\text{inf}}^{\text{inf}} (p); \forall t, c, l, \Gamma^+ \in \{\Gamma^{a0^*}, \Gamma^{a1^*}, \Gamma^{a2^*}\}, \tag{40}
\]

3 | NUMERICAL RESULTS

3.1 | Test system data and main assumptions

In order to further investigate the applicability of the proposed framework, it is applied to the Garver 6-bus test system shown in Figure 1. This system is comprised of 6 buses, 3 generators, and 6 transmission lines with 1110 MW installed capacity and 760 MW peak load. In this system, the operating costs of generating units are assumed to be 10, 20, and 30 $/MWh for buses 1, 3, and 6, respectively [37]. The complete bus data of the
TABLE 2  Network bus data—Garver Test System

| Bus No. | Generating Cost ($/MWH) | Minimum Capacity (MW) | Maximum Capacity (MW) | Peak Load (MW) |
|---------|-------------------------|-----------------------|-----------------------|----------------|
| 1       | 10                      | 0                     | 150                   | 80             |
| 2       | 0                       | 0                     | 240                   | 80             |
| 3       | 20                      | 0                     | 360                   | 80             |
| 4       | 0                       | 0                     | 160                   | 80             |
| 5       | 0                       | 0                     | 240                   | 80             |
| 6       | 30                      | 0                     | 600                   | 80             |

TABLE 3  Available and candidate transmission lines data—Garver Test System

Available Transmission Lines Data

| Bus No. | Line No. | Investment Cost (m$) | X (p.u.) | Capacity (MVA) |
|---------|----------|----------------------|----------|----------------|
| 1       | 1        | 2                    | 40       | 0.4            | 100            |
| 2       | 1        | 4                    | 60       | 0.6            | 80             |
| 3       | 1        | 5                    | 20       | 0.2            | 100            |
| 4       | 2        | 3                    | 20       | 0.2            | 100            |
| 5       | 2        | 4                    | 40       | 0.4            | 100            |
| 6       | 3        | 5                    | 20       | 0.2            | 100            |

Candidate Transmission Lines Data

| Bus No. | Line No. | Investment Cost (m$) | X (p.u.) | Capacity (MVA) |
|---------|----------|----------------------|----------|----------------|
| 1       | 2        | 6                    | 30       | 0.3            | 100            |
| 2       | 4        | 6                    | 30       | 0.3            | 100            |

The results associated with three cases include the expansion plans, investment, operation, O&M, reliability and the total costs which are presented in Table 4. New transmission lines and CAES units are summarised in Table 2 [37]. Moreover, the data associated with available and candidate transmission lines are presented in Table 3 [38]. Finally, 24-h demand profile for two sample days in summer and winter are depicted in Figure 2 [39].

Investment costs of CAES units that depend on the rated power and reservoir capacity include (i) power dependent and (ii) energy dependent portions. In this paper, investment costs of CAES units are assumed to be $425/kW and $53/kWh for power dependent and energy dependent costs, respectively. Moreover, the O&M costs that include fixed and variable portions are $1.42/kW/year and $0.0001/kWh. Maximum level of CAESs power and energy are considered to be 100 MW and 600 MWh, respectively [9]. Furthermore, 24-h price of electricity for CAESs discharged power is shown in Figure 3 [27]. The natural gas cost, heat rate, and energy ratio are $3.5/GJ, 4185 MJ/MWh, and 0.75, respectively, [40] and the average value of curtailed load is $39228/MWh [7].

In this paper, the annual discount rate is defined as the “return rate earned on an investment” [41] and is taken 0.12 [42]. The probability of contingency scenarios is supposed to be the same for all transmission line outages in outage hours and is considered 0.004 [6], [39]. The transmission line repair time (i.e. the time it takes the repair crews to re-install each interrupted transmission line) is supposed to be 10 h [43]. A 30-year planning horizon is considered in the study, where a maximum of two installed transmission lines in each corridor and one deployed CAESs at each bus are taken into account. Finally, all optimisation engines are tried using GAMS 24.1.3 software and CPLEX solver on a server with 7-core processor and 32 GB of RAM.

FIGURE 2 Twenty-four hour daily demand profile for two sample days in summer and winter in % (100% means peak load) [39]

FIGURE 3 Twenty-four hour daily price of electricity for CAESs discharged power in $/MWh [27]

3.2 Study results and analysis

Detailed analyses of the proposed framework include the following three cases:

- Case 1—ESS units are not included in the expansion studies of transmission network.
- Case 2—All the expansion candidates (transmission lines and CAES units) are considered.
- Case 3—The same as Case 2, except that the N-1 reliability criterion is incorporated.

The results associated with three cases include the expansion plans, investment, operation, O&M, reliability and the total costs which are presented in Table 4. New transmis-
sion lines are mostly installed in the corridors previously without a line and near critical load points. By simultaneous consideration of CAES units and transmission lines, the number of installed lines in Case 2 decreases in comparison with that in Case 1. In other words, the network can more efficiently satisfy the system demand and alleviate the transmission lines congestions in Case 2 despite removal of corridors 2–6. This is implied from the reduction in the system operation cost to 291.1 M$. Moreover, although Case 2 features a higher investment cost compared to Case 1, the total cost decreases to 95.5 M$. Furthermore, the O&M cost increases to 2.7 M$ in Case 2 due to using CAES units. Thus, while installation of CAESs introduces additional network investment costs, it can postpone the investments needed for construction of new transmission lines, and decrease transmission line congestions and total costs due to lower utilisation of costly generators.

In Case 3, contingency conditions have resulted in additional installation of several new transmission lines and CAES units. Therefore, the highest number of installed transmission lines and CAES units is reported in Case 3 to ensure the reliability criterion. Also, according to Table 4, corridors 2–4 and 2–6 as well as buses 2 and 3 are more vulnerable than the others under contingencies, where new transmission lines and CAES units are installed in Case 3 when compared to Case 2. Under contingencies, the investment, O&M, and the total costs expectedly increase in Case 3 compared to Case 1 and Case 2. However, the lowest operation cost in Case 3 in comparison with others can be explained by CAESs’ greatest features to reduce the usage of generators and full capacity of transmission lines. In detail, additional transmission lines and CAESs are installed in Case 3, and hence, more cost-effective generators can be used for supplying the loads. In other words, since operational limitations have been reduced, the system can operate more efficiently. Note that there is no reliability cost in Case 3 meaning that N-1 criterion is fully satisfied. On the other hand, the network with no integrated CAESs cannot satisfy the system loads under N-1 conditions due to the increase in transmission lines congestion. This observation highlights the efficacy of CAESs in reducing the TEP costs.

### 4 SENSITIVITY ANALYSIS

A sensitivity analysis is performed to investigate the impacts of load growth and the increase in the CAESs investment cost on the study results. The results of the sensitivity analyses including the increase in CAESs investment cost by 25% and 5% peak load growth are presented in Tables 5 and 6, respectively.

One can see in Table 5 that due to higher investment cost of CAESs, the number of installed CAESs decreases compared to that presented in Table 4. Based on the results presented in Case 2 in Table 4, bus 4 is more vulnerable because a CAES unit is decided to be installed at this bus (similar to Case 2 in Table 4) despite the increase in CAESs investment cost; however, to compromise the removal of CAES units from buses

| TABLE 4 | Investment results—Garver Test System |
|---------|--------------------------------------|
| Corridors/Buses | Case 1 | Case 2 | Case 3 |
| Installed lines 1 and 2 | 0 | 0 | 0 |
| 1–4 | 0 | 0 | 0 |
| 1–5 | 0 | 0 | 0 |
| 2 and 3 | 0 | 0 | 0 |
| 2–4 | 0 | 0 | 0 |
| 2–6 | 1 | 0 | 2 |
| 3–5 | 1 | 1 | 2 |
| 4–6 | 2 | 2 | 2 |
| Installed CAESs | 1 | 0 | 0 |
| 2 | 0 | 1 |
| 3 | 0 | 1 |
| 4 | 1 | 1 |
| 5 | 1 | 1 |
| 6 | 1 | 1 |
| Investment cost (M$) | 130.0 | 322.9 | 571.5 |
| Operation cost (M$) | 984.8 | 693.7 | 549.5 |
| O&M cost (M$) | 0.0 | 2.7 | 4.1 |
| Reliability cost (M$) | 0.0 | 0.0 | 0.0 |
| Total cost (M$) | 1114.8 | 1019.3 | 1125.1 |

| TABLE 5 | CAESs investment costs sensitivity analysis—Garver Test System |
|---------|--------------------------------------|
| Corridors/Buses | Case 1 | Case 2 | Case 3 |
| Installed lines 1 and 2 | 0 | 0 | 0 |
| 1–4 | 0 | 0 | 0 |
| 1–5 | 0 | 0 | 0 |
| 2 and 3 | 0 | 0 | 0 |
| 2–4 | 0 | 0 | 0 |
| 2–6 | 1 | 0 | 2 |
| 3–5 | 1 | 1 | 2 |
| 4–6 | 2 | 2 | 2 |
| Installed CAESs | 1 | 1 | 0 |
| 2 | 0 | 1 |
| 3 | 0 | 1 |
| 4 | 1 | 0 |
| 5 | 0 | 0 |
| 6 | 0 | 1 |
| Investment cost (M$) | 130.0 | 285.8 | 478.6 |
| Operation cost (M$) | 984.8 | 777.7 | 714.5 |
| O&M cost (M$) | 0.0 | 2.1 | 2.7 |
| Reliability cost (M$) | 0.0 | 0.0 | 0.0 |
| Total cost (M$) | 1114.8 | 1065.6 | 1195.8 |
TABLE 6  Load growth sensitivity analysis—Garver Test System

| Corridors/Buses     | Case 1 | Case 2 | Case 3 |
|---------------------|--------|--------|--------|
| Installed lines     |        |        |        |
| 1 and 2             | 0      | 0      | 1      |
| 1–4                 | 0      | 0      | 2      |
| 1–5                 | 0      | 0      | 0      |
| 2 and 3             | 1      | 1      | 0      |
| 2–4                 | 0      | 0      | 2      |
| 2–6                 | 2      | 0      | 2      |
| 3–5                 | 1      | 1      | 2      |
| 4–6                 | 2      | 2      | 2      |
| Installed CAESs     |        |        |        |
| 1                   | 0      | 0      | 1      |
| 2                   | 0      | 0      | 1      |
| 3                   | 0      | 0      | 0      |
| 4                   | 1      | 1      | 1      |
| 5                   | 1      | 1      | 1      |
| 6                   | 1      | 1      | 1      |
| Investment cost (M$) | 160.0  | 322.9  | 771.5  |
| Operation cost (M$) | 1054.7 | 764.0  | 606.3  |
| O&M cost (M$)       | 0.0    | 2.7    | 4.0    |
| Reliability cost (M$) | 0.0   | 0.0    | 625.6  |
| Total cost (M$)     | 1214.7 | 1089.6 | 2007.4 |

5 and 6, these units at buses 5 and 6 (Table 4) is replaced by installing only one CAES at bus 1 in order to justify the increase in CAESs investment cost. In order to clarify the rationale in adding one CAES at bus 1 in Case 2 (Table 5) despite the increase in CAESs’ investment cost compared to Case 1, Figures 4 and 5 are provided demonstrating the 24-h power flow of the transmission lines connected to bus 1 (Line No.: 1, 2, 3). The power flow of these transmission lines in Case 1 are presented in Figure 4, while those of Case 2 are shown in Figure 5. As it can be seen, the power flows in Figure 5 are smoother than those presented in Figure 4. Therefore, despite using expensive CAES units in Case 2, one unit is added at bus 1 to smoothen the power flow of the connected lines to this bus; moreover, the power flows at 1:00 AM to 6:00 AM are approximately negligible in Figure 5 compared to that in Figure 4, which means that CAES stored the extra electricity (not used by demand during the night time) to improve the fluctuations in line power flows presented in Figure 4. As a result, although the cost in Case 2 are observed higher than that in Case 1 due to using expensive CAESs, the power flow across the transmission lines is improved.

According to Case 3 in Table 5, buses 2, 3, and 6 are more vulnerable than the others under contingency scenarios where new CAES units are installed similar to Case 3 results in Table 4. In spite of the decrease in CAESs installation, the expansion plan for installed transmission lines remains the same in Tables 4 and 5. Therefore, the transmission line flows increase in Table 5 in comparison with Table 4, which can be reflected in the increased system operation cost. The higher transmission line flows can be translated to the higher usage of generation capacity in supplying the demand when compared to Table 4. Therefore, higher CAESs investment costs lead to a reduction in the transmission lines investment and O&M costs, while the operation and total costs have increased in the light of higher usage of generators as well as transmission lines capacity. Finally, similar to Table 4, no reliability cost in Case 3 reflects that the N-1 criterion is fully satisfied.

As itemised in Table 6, the number of installed transmission lines increases in Case 1 and Case 3 compared to Table 4 in order to satisfy the 5% load growth; hence, the investment, operation and total costs increase. It should be noted that the expansion plans in Case 2 in Table 6 is similar to that of Case 2 in Table 4; thus, the investment cost remains constant. However, the system utilises a higher transmission lines flow capacity, CAESs, as well as generating units under load growth conditions which, in turn, leads to an increase in operation and total costs. On the other hand, with the similar number of CAES units in Tables 4 and 6, the O&M cost has not changed. Moreover, according to Case 3 in Table 6, load curtailment increases in comparison with Table 4, revealing the system inability to fully satisfy the N-1 criterion under the load growth scenarios. Finally, according to the results presented in Tables 4–6, investment on CAES units is an efficient mechanism to reduce the total costs, control the transmission lines congestion, and relax or defer the need for transmission lines construction in the near future. Consequently, CAESs can be used as a modern technology in the modern power grids of the future in order to improve the TEP studies.
5  LARGE-SCALE RTS TEST SYSTEM

5.1  Test system data and main assumptions

In another case study, RTS 24-bus test system (Figure 6) [39] is considered to further investigate the applicability of the proposed framework. In this regard, the bus and transmission lines data are presented in Tables 7 and 8, respectively [2], [39]. The transmission lines investment cost is supposed to be 350 $/MVA*mile [6]. The other assumptions are the same as those taken for the Garver Test System. Note that due to the high reliability level of the RTS test case originally, the network generation portfolio and demand profiles are intensified to 2.2 times of the original values to further demonstrate the promising efficiency of the proposed framework.
TABLE 7  Network bus data—RTS Test System

| Bus No. | Generating Cost ($/MWH) | Minimum Capacity (MW) | Maximum Capacity (MW) | Peak Load (MW) |
|---------|--------------------------|------------------------|-----------------------|----------------|
| 1       | 12.1450                  | 62.4                   | 192                   | 108            |
| 2       | 12.1450                  | 62.4                   | 192                   | 97             |
| 3       | 0                        | 0                      | 0                     | 180            |
| 4       | 0                        | 0                      | 0                     | 74             |
| 5       | 0                        | 0                      | 0                     | 71             |
| 6       | 0                        | 0                      | 0                     | 136            |
| 7       | 17.9240                  | 75                     | 300                   | 125            |
| 8       | 0                        | 0                      | 0                     | 171            |
| 9       | 0                        | 0                      | 0                     | 175            |
| 10      | 0                        | 0                      | 0                     | 195            |
| 11      | 0                        | 0                      | 0                     | 0              |
| 12      | 0                        | 0                      | 0                     | 0              |
| 13      | 20.0230                  | 207                    | 591                   | 265            |
| 14      | 0                        | 0                      | 0                     | 194            |
| 15      | 9.2706                   | 66.3                   | 215                   | 317            |
| 16      | 9.2706                   | 54.3                   | 155                   | 100            |
| 17      | 0                        | 0                      | 0                     | 0              |
| 18      | 5.3450                   | 100                    | 400                   | 333            |
| 19      | 0                        | 0                      | 0                     | 181            |
| 20      | 0                        | 0                      | 0                     | 128            |
| 21      | 5.3450                   | 100                    | 400                   | 0              |
| 22      | 0.5                      | 60                     | 300                   | 0              |
| 23      | 8.9190                   | 248.6                  | 660                   | 0              |
| 24      | 0                        | 0                      | 0                     | 0              |

5.2 Study results and analysis

The expansion plans, investment, operation, O&M, reliability and total costs are presented in Table 9. The number of installed transmission lines decreases in Case 2 in comparison with that in Case 1 due to using the CAES units. In this context, despite the removal of corridor 7 and 8, the system can efficiently operate by using a lower capacity of transmission lines. Therefore, according to Table 9, the operation cost and total cost decrease to 1845 M$ and 277.3 M$ in Case 2, respectively. On the other hand, by using CAES units, investment cost and O&M cost, respectively, increase to 1557.2 M$ and 10.5 M$. As a result, although installation of CAESs imposes additional investment and O&M costs, the total costs will decline similar to what was observed in the Garver Test System, which highlights the efficacy of CAESs integration.

To meet the N-1 criterion requirements, new transmission lines and CAES units are added in Case 3. Therefore, according to Table 9, corridors 6–10, 8 and 9, 11–14, 14–16, 16 and 17, and 17 and 18 are more vulnerable than others. In this case, the investment, O&M and total costs increase in comparison with the other cases, while the operation cost decreases. This was an expected observation as there are more CAES units and higher transmission capacity, and thus, the normal operation of the grid can be found more efficient. Also, the huge reliability cost in Case 3 implies that the network cannot fully satisfy the N-1 criterion, and there are some load curtailments in N-1 contingencies. In fact, with a general overview on three cases, one can understand that more trans-

TABLE 8  Transmission lines data—RTS Test System

| Line No. | Bus No. | Length (Miles) | X (p.u.) | Capacity (MVA) |
|----------|---------|----------------|----------|----------------|
| 1        | 1       | 2              | 3        | 0.0139         | 175            |
| 2        | 1       | 3              | 55       | 0.2112         | 175            |
| 3        | 1       | 5              | 22       | 0.0845         | 175            |
| 4        | 2       | 4              | 33       | 0.1267         | 175            |
| 5        | 2       | 6              | 50       | 0.1920         | 175            |
| 6        | 3       | 9              | 31       | 0.1190         | 175            |
| 7        | 3       | 24             | 0        | 0.0839         | 400            |
| 8        | 4       | 9              | 27       | 0.1037         | 175            |
| 9        | 5       | 10             | 23       | 0.0883         | 175            |
| 10       | 6       | 10             | 16       | 0.0605         | 175            |
| 11       | 7       | 8              | 16       | 0.0614         | 175            |
| 12       | 8       | 9              | 43       | 0.1651         | 175            |
| 13       | 8       | 10             | 43       | 0.1651         | 175            |
| 14       | 9       | 11             | 0        | 0.0839         | 400            |
| 15       | 9       | 12             | 0        | 0.0839         | 400            |
| 16       | 10      | 11             | 0        | 0.0839         | 400            |
| 17       | 11      | 12             | 0        | 0.0839         | 400            |
| 18       | 11      | 13             | 33       | 0.0476         | 500            |
| 19       | 11      | 14             | 29       | 0.0418         | 500            |
| 20       | 12      | 13             | 33       | 0.0476         | 500            |
| 21       | 12      | 23             | 67       | 0.0966         | 500            |
| 22       | 13      | 23             | 60       | 0.0865         | 500            |
| 23       | 14      | 16             | 27       | 0.0389         | 500            |
| 24       | 15      | 16             | 12       | 0.0173         | 500            |
| 25 (2)   | 15      | 21             | 34       | 0.0490         | 500            |
| 26       | 15      | 24             | 36       | 0.0519         | 500            |
| 27       | 16      | 17             | 18       | 0.0259         | 500            |
| 28       | 16      | 19             | 16       | 0.0231         | 500            |
| 29       | 17      | 18             | 10       | 0.0144         | 500            |
| 30       | 17      | 22             | 73       | 0.1053         | 500            |
| 31 (2)   | 18      | 21             | 18       | 0.0259         | 500            |
| 32 (2)   | 19      | 20             | 27.5     | 0.0396         | 500            |
| 33 (2)   | 20      | 23             | 15       | 0.0216         | 500            |
| 34       | 21      | 22             | 47       | 0.0678         | 500            |
**TABLE 9** Investment results—RTS Test System

| Installed lines | Case 1 | Case 2 | Case 3 |
|-----------------|-------|-------|-------|
| 1 and 2         | 0     | 0     | 0     |
| 1–3             | 0     | 0     | 0     |
| 1–5             | 0     | 0     | 0     |
| 2–4             | 0     | 0     | 0     |
| 2–6             | 0     | 0     | 0     |
| 3–9             | 0     | 0     | 0     |
| 3–24            | 0     | 0     | 0     |
| 4–9             | 0     | 0     | 0     |
| 5–10            | 1     | 1     | 2     |
| 6–10            | 1     | 1     | 2     |
| 7 and 8         | 1     | 0     | 2     |
| 8 and 9         | 1     | 1     | 2     |
| 8–10            | 0     | 0     | 1     |
| 9–11            | 0     | 0     | 0     |
| 9–12            | 0     | 0     | 0     |
| 10 and 11       | 0     | 0     | 0     |
| 10–12           | 0     | 0     | 0     |
| 11–13           | 0     | 0     | 0     |
| 11–14           | 1     | 1     | 2     |
| 12 and 13       | 0     | 0     | 0     |
| 12–23           | 0     | 0     | 0     |
| 13–23           | 0     | 0     | 0     |
| 14–16           | 2     | 2     | 2     |
| 15 and 16       | 1     | 0     | 2     |
| 15–21           | 0     | 0     | 0     |
| 15–24           | 0     | 0     | 0     |
| 16 and 17       | 2     | 2     | 2     |
| 16–19           | 0     | 0     | 1     |
| 17 and 18       | 1     | 1     | 2     |
| 17–22           | 0     | 0     | 0     |
| 18–21           | 0     | 0     | 0     |
| 19 and 20       | 0     | 0     | 0     |
| 20–23           | 0     | 0     | 0     |
| 21 and 22       | 0     | 0     | 0     |

| Installed CAESs | Case 1 | Case 2 | Case 3 |
|-----------------|-------|-------|-------|
| 1               | 1     | 1     | 1     |
| 2               | 1     | 1     | 1     |
| 3               | 1     | 1     | 1     |
| 4               | 1     | 1     | 1     |
| 5               | 1     | 1     | 1     |
| 6               | 1     | 1     | 1     |
| 7               | 1     | 1     | 1     |
| 8               | 1     | 1     | 1     |
| 9               | 0     | 0     | 1     |
| 10              | 1     | 1     | 1     |
| 11              | 1     | 1     | 1     |

(Continues)

**TABLE 9** (Continued)

| Corridors/Buses | Case 1 | Case 2 | Case 3 |
|-----------------|-------|-------|-------|
| 12              | 1     | 1     | 1     |
| 13              | 0     | 0     | 0     |
| 14              | 1     | 1     | 1     |
| 15              | 1     | 1     | 1     |
| 16              | 1     | 1     | 1     |
| 17              | 1     | 1     | 1     |
| 18              | 1     | 1     | 1     |
| 19              | 1     | 1     | 1     |
| 20              | 1     | 1     | 1     |
| 21              | 1     | 1     | 1     |
| 22              | 1     | 1     | 1     |
| 23              | 1     | 1     | 1     |
| 24              | 0     | 1     |     |

| Investment cost (M$) | 29.3 | 1586.5 | 1757.1 |
| Operation cost (M$)   | 3214.2 | 1369.2 | 1225.9 |
| O&M cost (M$)         | 0.0 | 10.5 | 11.5 |
| Reliability cost (M$) | 0.0 | 0.0 | 1228.1 |
| Total cost (M$)       | 3243.5 | 2966.2 | 4222.6 |

mission lines or CAES units with higher capacity should be deployed in order to control the reliability cost in contingency scenarios.

### 6 CONCLUSION

In this paper, a new mathematical model is proposed that captures the impacts of CAESs on the TEP problem. On this basis, the Big-M method and an innovative approach were presented to transform the MINLP optimisation model for the ES-TEP problem to a MILP formulation. This model can be solved using off-the-shelf linear optimisation methods, thereby effectively addressing the computational complexity and performance accuracy. In addition, the optimisation problem can be performed in a single step, opposed to the state-of-the-art methods that require decomposition. The proposed algorithm was applied to the Garver 6-bus and RTS 24-bus test systems and also N-1 criterion was implemented in the expansion studies to address the system reliability considerations during emergencies. The results demonstrated the effectiveness of the proposed algorithm and that investment in CAES units is an effective mechanism to reduce the transmission expansion costs by deferring the installation costs of new transmission lines. Future research could include the integration of RES in the network and the corresponding models in the proposed framework. Additionally, the uncertainties in RES and loads can be studied in the future to develop a robust and uncertainty-aware decision-making platform for co-planning TEP and energy storage systems.
Nomenclature

Indices and Sets

- $t, T$: Index and number of time stamps $\{1, \ldots, 24\}$.
- $i, L$: Index and number of transmission lines.
- $l, I$: Index and number of buses.
- $\Gamma$: Index of all transmission line variables $\{\Gamma^0, \Gamma^1, \Gamma^2\}$.
- $\Gamma^0$, $\Gamma^1$, $\Gamma^2$: Index of online transmission line variables.
- $\Gamma^0$, $\Gamma^1$, $\Gamma^2$: Index of the $1^{st}$ and $2^{nd}$ installed transmission line variables.
- $\Gamma^+$: Index of all transmission line variables under contingency $\{\Gamma^{+0}, \Gamma^{+1}, \Gamma^{+2}\}$.
- $\Gamma^{+0}$: Index of online transmission line variables under contingency.
- $\Gamma^{+1}$, $\Gamma^{+2}$: Index of $1^{st}$ and $2^{nd}$ installed transmission line variables under contingency.
- $\Gamma^0$, $\Gamma^1$, $\Gamma^2$: Index of the $1^{st}$ and $2^{nd}$ installed transmission line variables under contingency.
- $d$: Index of winter/summer days $\{d_1, d_2\}$.
- $cd$: Index of charging or discharging states $\{c_d, c_d\}$.
- $\alpha$: Index and number of contingencies.
- $p$: Index of transmission line outage time periods $\{1, \ldots, 24\}$.
- $n, N$: Index and number of investment time.

Parameters

- $c_{ih}$: Investment cost of transmission line $l$.
- $c_{ip}, c_{i+}$: Investment cost of CAES power and energy level.
- $f_{OM}, f_{OM}$: Fixed and variable O&M cost.
- $y_{ij}$: Operation cost of generating unit $i$ at bus $j$.
- $\lambda$: Cost of natural gas.
- $\lambda_{ij}^0$: Binary parameter of online transmission line $l$.
- $y(d)$: Number of winter/summer days in a year.
- $\xi$: Day-ahead price of electricity at time $t$.
- $\alpha_{il}^{+0}$, $\alpha_{il}^{+2}$: Connectivity matrix of online and installed transmission line $l$ to bus $i$.
- $D_{ij}$: Demands at time $t$ and bus $i$ in summer/winter.
- $\gamma_{ij}$: Susceptance of transmission line $l$.
- $\gamma_{ij}$: Maximum capacity of transmission line $l$.
- $G_i$, $G_i$: Minimum and maximum power of generating unit $i$ at bus $i$.
- $\gamma_{ij}$: CAES power maximum capacity.
- $\delta_{ij}$: CAES state of charge maximum capacity.
- $HR, ER$: Heat rate and energy ratio of CAES.
- $df, ds$: Discount factor and discount rate.
- $HR$: Probability of contingencies.
- $VolLL$: Value of Lost Load.

Variables

- $\text{cost}_{il}^{+0}$: Investment cost of installed transmission lines.
- $\text{cost}_{il}^{+2}$: Investment cost of installed CAESs.
- $\text{cost}_i$: System operation cost in summer/winter.
- $\text{cost}_{OM}^d$: System O&M cost in summer/winter.
- $\text{cost}_d$: Load curtailment cost in summer/winter.
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