Necessity of Joint Resource and Transmission Expansion Planning in Presence of System and Policy Uncertainties

Mahdi Mehrtash[1], *Senior Member, IEEE*, Benjamin F. Hobbs[1], *Life Fellow, IEEE*, and Reza Mahroo[2], *Student Member, IEEE*

[1] Ralph O'Connor Sustainable Energy Institute, Johns Hopkins University, Baltimore, MD 21218, USA

[2] Department of Electrical and Computer Engineering, Louisiana State University, Baton Rouge, LA 70803, USA

mahdi.mehrtash@ieee.org

2023 IEEE Texas Power and Energy Conference (TPEC) | 978-1-6654-9071-9/23/$31.00 ©2023 IEEE | DOI: 10.1109/TPEC56611.2023.10078637

***Abstract*—A clear gap exists between the way that power system expansion planning is modeled in academic research papers and the real-world practice of system planners. To address this gap, we perform two comparative numerical case studies on a large-scale ERCOT-like test system. In the first study, we quantify the economic benefit of optimization-based TEP over the approach of project-by-project screening of expansion plans that is more popular in industry. The second study compares the solutions of resource-only expansion planning with those of joint resource and transmission expansion planning considering four future scenarios representing uncertainties that exist in emission reduction policies and forecasted demand. Numerical case studies illustrate the significant economic and technical benefits of co-optimization in resource and transmission expansion planning.**

***Index Terms*— Transmission expansion planning, generation expansion planning, joint resource and transmission expansion, co-optimization, policy and demand uncertainties.**

I. Introduction

PLANNING transmission and generation investments ("power system expansion") is a crucial task in power engineering for several reasons. These include the needs to meet demand growth, to comply with environmental regulations, to avoid network congestion, to support system reliability, and to create a level playing field by giving all market participants fair access to the network. Transmission networks play a key role in power system operation, and they must be carefully planned to accommodate the shifts in the timing and location of power generation and use resulting from the growth of renewables and anticipated electrification of transportation and building energy use [1]. In particular, transmission expansion planning (TEP) aims to determine the timing, location, number, and voltage of new lines required to be installed in order to ensure an adequate level of energy supply, meet reliability standards, and provide fair access to power suppliers [2]. TEP is intertwined with other power system expansion problems, especially generation expansion planning (GEP), and it has been demonstrated that a coordinated solution ("co-optimization") of resource and transmission expansion is more beneficial in the long run [3].

The interdependencies of TEP and GEP mean that their solutions will be suboptimal if they are obtained individually rather than coordinated. However, planners tend to derive these decisions separately because they are distinct market players. TEP decisions are made by independent system operators (ISOs) and regional transmission organizations (RTOs), while GEP decisions are made by generation companies. In recent years, due to investing only in generation expansion, the Electric Reliability Council of Texas (ERCOT) had to curtail 28.4% of installed renewable generation due to voltage stability constraints and insufficient transmission capacity [4].

Mathematically speaking, the TEP problem is often formulated as a mixed-integer nonlinear program. Various TEP models based upon network representations with various levels of fidelity and complexity are proposed in the literature. These representations include the transshipment ("pipes and bubbles") model, the linearized DC model, the disjunctive model, the hybrid model, and the AC power flow-based model [5-9]. For instance, reference [10] proposes a TEP model with a shift-factor-based representation of power flow that has the same accuracy as a linearized DC model while being computationally cheaper. Recently, a computationally efficient solution algorithm for the robust dynamic TEP model considering security constraints has been presented in [11].

Meanwhile, the GEP problem is motivated by the aging of generation equipment, demand growth, and environmental concerns (e.g., renewable portfolio standards and emission reduction policies). GEP is generally approached in two ways: either in a market framework that simulates investments by profit-maximizing suppliers, or by adopting a centralized model using the "integrated resource planning" paradigm [1]. As an example of the latter, cost and environmental impacts are both considered objectives of a multi-objective GEP problem in [12].

The benefits of joint, or "co-optimized", generation and transmission expansion planning (GTEP) is highlighted in [13, 14]. We mention just a few other examples here. For instance, [15] proposes a probabilistic GTEP model considering reliability criteria for a random generator or line outages. Reference [16] proposes a risk-based GTEP that incorporates the propagating effect of contingencies across the power system. Models for deploying storage devices in expansion planning studies have been also proposed in the literature. In this regard, [17] presents a nonconvex optimization model to study the impacts of energy storage systems on a TEP problem. Furthermore, an adaptive robust optimization framework for coordinating TEP and storage devices is proposed in [18].

Almost all models proposed in the literature for power system expansion planning problems are optimization-based. Despite all of this, project-by-project screening of expansion plans is more popular in industrial practice, and, with the exception of GEP [19], optimization-based models are not widely used. Screening approaches include simulating and evaluating many alternatives under different scenarios using a simple model that delivers a relative ranking of alternatives using, e.g., benefit-cost ratios [20]. Clearly, a gap can be observed between the power system expansion models, especially TEP and co-optimization models, that have been proposed in academic research papers and the current project-by-project screening that is practiced by the industry.

Another important aspect of power system expansion planning is the presence of uncertainty in forecasting the future demand, supply, and regulatory conditions of the power system. In this regard, the policy uncertainty and the error of forecasted demands are significant.

In this paper, we used a large-scale ERCOT-like test system to perform two comparative numerical studies. In the first study, to address the gap between academic research papers and industry practice, we quantify the economic benefit of optimization-based TEP over the approach of screening individual candidate lines. The second study concerns the comparison between the solutions of resource-only expansion planning (especially GEP) with those of joint resource and transmission expansion planning considering four future scenarios representing uncertainties that exist in emission reduction policies and forecasted demand.

The remainder of the paper is organized as follows. The methodology of this study and the general form of an optimization-based expansion planning model is presented in section II. Using a large-scale test system, the two proposed numerical studies are explained in section III. Finally, section IV includes the discussion and conclusions of this study.

II. Methodology

A clear gap exists between the way that the power transmission expansion planning problem is modeled in academic research papers and the way that it is done in the real-world by ISOs/RTOs. While in the literature, TEP is modeled as a mixed-integer optimization problem, ISOs/RTOs perform a project-by-project screening to select the best individual line to be built next [4]. Some of the reasons why ISOs/RTOs use such heuristic approaches for TEP include:

- While it might be economically optimal, the solutions of optimization-based TEP models might not satisfy the physical constraints of power systems (e.g., static and dynamic stability constraints) because those constraints are simplified or omitted.
- Existing solution algorithms for realistically-sized mixed-integer optimization-based TEP models can be intractable given the size of the large-scale real-world power systems.

However, as we will illustrate numerically in the next section, the technical and economic inefficiencies of solutions from the screening approach can also be significant. In addition, recently developed solution algorithms are capable of solving large-scale TEP problems with more realistic system representations, including static stability constraints (i.e., respecting nodal voltage limitations and modeling the reactive power flow through lines), with reasonable runtimes [2, 7]. Furthermore, a post-processing dynamic stability step can be done after obtaining the solution of optimization-based TEP to guarantee the feasibility of the selected configuration.

In the first numerical case study of this paper, we quantify the incremental economic and technical benefits of performing optimization-based TEP instead of a project-by-project screening approach on a large-scale test system.

The general form of an optimization-based TEP is as (1), below, where the objective function $f(x)$ includes the investment cost of new transmission lines and the total operation cost of the system over multiple load and generator availability realizations. If power losses are modeled, the operation cost term in the objective function might be replaced by the total power loss of the system. To have a mathematical optimization model that is always feasible, the possibility of shedding nodal loads is also modeled as decision variables, and a term representing load shedding cost is added to the objective function [21].

The feasibility set of the optimization-based TEP is constructed by the set of equality constraints $g(x) = 0$ and the set of inequality constraints $h(x) \leq 0$. Depending on the system planner's needs and application, the set of constraints can represent technical, economic, environmental, or policy restrictions. Among the equality constraints are nodal power balances in the system, load flow representations (e.g., flow depends on phase angle differences), and energy balances for storage. The set of inequality constraints includes thermal limits of transmission lines, output power limit of generating units, energy storage representations, etc. [1].

$$\begin{aligned} &\min f(x) \\ s.t. \quad & g(x) = 0; \\ & h(x) \leq 0; \end{aligned} \tag{1}$$

In the GTEP model, the objective function $f(x)$ also includes investment costs of new generating units and storage devices. It is intuitive that the solution of joint resource and transmission expansion planning (i.e., GTEP) is more optimal than that of resource-only expansion planning (i.e., GEP) from both technical and economic perspectives. To numerically quantify this benefit, in the second case study of this paper, we compare the solution of GEP with GTEP for a large-scale test system. In this study, multiple future scenarios are considered to model the uncertainties that exist in emission reduction policies and forecasted demand.

III. Numerical Case Study

A. Test System Description and Computer Setup

For the numerical case study, the ERCOT-like test system developed by NREL in the framework of PERFORM project is used: https://github.com/NREL-SIIP/ExtremeSolarTexas. This large-scale test system has 2,103 buses, 3,330 transmission lines, and 526 generating units, including Coal, Gas-CC, Gas-CT, Nuclear, Hydro, PV, Wind, and energy storage devices. The installed capacity and the peak demand are about 127 GW and 75 GW, respectively. The target planning horizon is 2030 and the load-shedding cost is assumed to be \$5000/MWh, which equals the current ERCOT's value of lost load [22].

To check the connectivity of the test system, its visualization is obtained using "plot_mpc" in MATPOWER (see Fig. 1). The thickness of each edge corresponds to a line's voltage level while its length represents an index of power transfer capacity obtained from the summation of power transfer distribution factors [23]. This representation is for the system assuming none of the candidate new circuits are added; of course, a diagram could also be constructed for a system that also includes a selected set of new lines. For this test system, as expected from a realistic power system, transmission lines with higher voltage transfer more energy between their sending and receiving buses. Furthermore, it can be seen that the test system consists of meshed high-voltage transmission lines as well as radial distribution lines (as shown by red circles in Fig. 1).

The Johns Hopkins stochastic multistage integrated network expansion (JHSMINE) tool is used in this study [24, 25]. JHSMINE is capable of running a stochastic multistage expansion planning; however, here we apply its deterministic expansion planning mode for a single planning horizon. For this study, the JHSMINE model is re-written in Julia 1.7 [26] using JuMP v1.3 [27] as the mathematical optimization modeling language. To solve the mixed-integer programming model, ILOG CPLEX v20.1.0 [28] is used. All simulations are run on a Lenovo PC with 64 gigabytes of RAM and a 2.60 GHz Intel CPU with 6 cores.

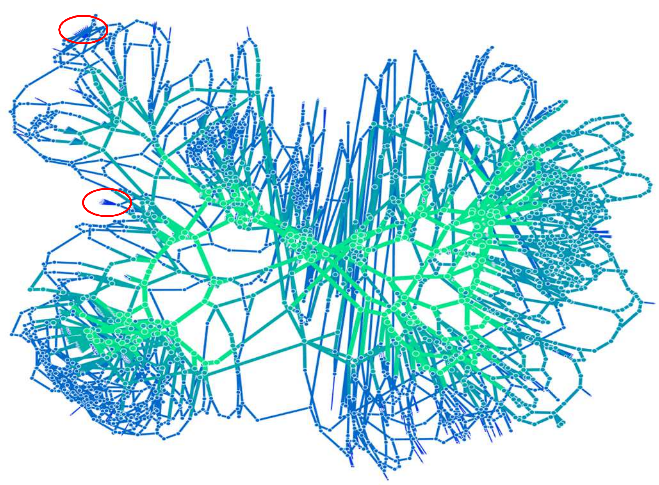

Fig. 1. Test system visualization using "plot_mpc" in MATPOWER (two sets of radial distribution lines are shown by red circles for the sake of example).

B. Study 1: Screening vs. Optimization-based TEP

In this study, we quantify the economic benefit of optimization-based TEP over the approach of screening individual candidate lines, which is a popular approach among many system operators such as ERCOT [4].

First, a set of 10,000 distinct candidate transmission lines is generated randomly for the test system (i.e., 3,330 parallel to the existing lines plus 6,670 in new corridors).

Second is a screening step based on the incremental economic benefit of each new candidate line, considered one at a time. To execute this step, a linearized DC load flow-based optimal power flow (OPF) is run 10,000 times, with each run considering the existing system plus a single new candidate line. In our sample case, we assume for simplicity that every candidate circuit has the same electrical characteristics (reactance and thermal capacity); of course, in a real study, these characteristics would reflect the assumed length, conductors, and voltage. Figure 2 depicts the system operation cost (i.e., OPF objective value) when a new candidate line is added to the system (in blue) in comparison with the operation cost of the original system (in red). Due to the many higher values (increased cost) in the figure, the Braess paradox is obvious for the randomly generated candidate lines. According to the Braess paradox, adding a new random line to the network can actually deteriorate optimal operation of the network [29]. The sorted set of candidate lines according to economic benefit of each individual line is shown in Fig. 3. Almost half of the randomly generated candidate lines will increase the operation cost of the system if installed (see Fig. 3).

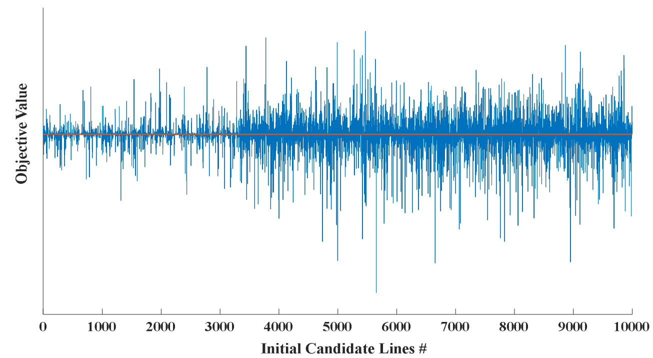

Fig. 2. Screening economic benefit of individual candidate lines.

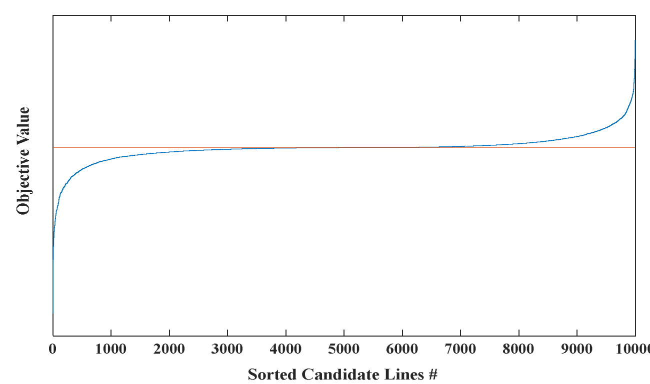

Fig. 3. Sorted set of candidate lines according to economic benefit of each individual line (shown from best performing to worst one).

Third, the best 50 candidate lines from the sorted set in terms of operating cost improvements are selected as the set of candidate lines in the expansion planning tool (i.e., JHSMINE). This step assumes simplistically that their investment costs are identical; in a real study, an operating benefit/investment cost ratio might be used instead for ranking. After running JHSMINE, the TEP solution is the selection of 27 particular new lines to be added to the original system (i.e., selected lines are {1, 4, 6-10, 12, 14, 15, 20-23, 30, 31, 33-35, 37, 39, 41-43, 45, 47, 48}). Note that 13 of the 27 selected lines are not in the top 27 lines in the screening analysis. Clearly, the optimization-based TEP solution differs greatly from a screening solution based just on choosing the first 27 lines from the sorted set.

The solutions of screening and optimization-based TEP are presented in Table I. As can be seen, the advantage of performing TEP in an optimization framework is significant in reducing both system operation cost as well as load shedding. In this numerical case study, the benefits (reduction in annual operation cost) for optimization-based TEP are more than twice as much (242%) as the benefits of the screening solution (see Table I), and load shedding is almost 80% less.

Therefore, one can conclude that the cost-benefit and system reliability improvements from different transmission investments will depend on each other, and the optimal portfolio of investments may differ from recommendations made on a project-by-project basis.

TABLE I. SCREENING VS. OPTIMIZATION-BASED TEP SOLUTIONS

	Annual operation cost (Billion $)	Load shedding during annual peak demand (MW)
Original system	7.57	3,093
Screening (adding first 27 lines)	6.99 (Benefit=0.5)	1,558
Optimization-based TEP (adding 27 lines selected by JHSMINE)	6.19 (Benefit=1.3)	366

It is worth mentioning that the significant difference between screening and optimization-based TEP solutions is not due to the linearized approximated network representation (i.e., the DC power flow model). As presented in [2], considering the full AC representation of the network (i.e., AC power flow model), the screening and optimization-based TEP solutions are again totally different. Table II, which is presented in [2], clearly shows that the six selected lines from the set of 50 candidate lines are not those that have been selected by screening (the set of 50 highest-ranked lines based on their individual incremental cost benefit for the system).

TABLE II. DIFFERENCE IN SCREENING AND OPTIMIZATION-BASED TEP SOLUTIONS CONSIDERING AC POWER FLOW REPRESENTATION OF NETWORK (RESULTS OF GLOBAL-TEP SOLVER [2])

($Gap^{tol} = 0.2\%$)	Gap %	Selected lines
30 candidate lines	0.14	{1, 2, 5, 12}
40 candidate lines	0.14	{1, 5, 12, 35, 36}
50 candidate lines	0.15	{1, 5, 12, 23, 36, 46}

C. Study 2: GEP vs. GTEP

In this numerical case study, the resource expansion planning solutions are compared with the *joint* resource and transmission expansion planning solutions. Multiple future scenarios are considered with respect to uncertainties that exist in emission reduction policies and forecasted demand. Investment costs for different lines are assumed to differ as well.

Considering the economic benefit of individual assets (i.e., OPF objective value) and following the approach presented in the previous section, assumed parameters for 25 candidate lines, 35 candidate generating units, and 10 candidate storage devices are presented in Table III-V, respectively.

To illustrate the impact of uncertainties in the forecasted load growth and the emission reduction policies, four different future scenarios are considered as presented in Table VI. The first scenario (i.e., **S1**) is the reference scenario with 10% projected load growth for the test system by the end of the planning horizon (i.e., 2030). The second (i.e., **S2**), third (i.e., **S3**), and fourth (i.e., **S4**) scenarios are, respectively, tight environmental regulations enforced by a high carbon tax, aggressive retirement of thermal units, and high load growth.

TABLE III. CANDIDATE TRANSMISSION LINE DATA

From bus	To bus	X (p.u.)	Thermal Capacity (MW)	Investment Cost (M$/y)
303	1197	0.03	400	14.49
304	449	0.03	400	18.59
304	1265	0.03	400	19.36
304	1847	0.03	400	7.36
484	551	0.03	400	19.36
497	119	0.03	400	14.84
498	748	0.03	400	12.28
505	811	0.03	400	9.18
505	1505	0.03	400	19.01
527	492	0.03	400	17.22
544	1630	0.03	400	19.56
668	1071	0.03	400	17
689	194	0.03	400	11.33
719	1750	0.03	400	6.46
818	492	0.03	400	18.7
819	985	0.03	400	6.9
825	669	0.03	400	17.74
1032	2039	0.03	400	16.88
1127	1630	0.03	400	18.74
1267	1254	0.03	400	15.18
1305	1267	0.03	400	13.2
1404	653	0.03	400	7.13
1405	304	0.03	400	19.47
1630	1101	0.03	400	5.54
1983	501	0.03	400	19.39

TABLE IV. CANDIDATE GENERATING UNITS DATA

Bus	Type	Pmax (MW)	Operation Cost ($/MWh)	Investment Cost (M$/y)
76	Wind	200	0	109.35
206	PV	150	0	62.06
268	Gas-CT	212.5	48.25	66.64
299	Wind	200	0	109.35
332	PV	150	0	62.06
361	Wind	200	0	109.35
586	Wind	200	0	109.35
825	Wind	200	0	109.35
887	PV	150	0	62.06
995	PV	150	0	62.06
1021	Wind	200	0	109.35
1151	PV	150	0	62.06
1259	PV	150	0	62.06
1281	PV	150	0	62.06
1330	Hydro	99	0	65.00
1379	PV	150	0	62.06
1380	PV	150	0	62.06
1428	PV	150	0	62.06
1563	PV	150	0	62.06
1594	Wind	200	0	109.35
1667	PV	150	0	62.06
1683	PV	150	0	62.06
1714	PV	150	0	62.06
1786	PV	150	0	62.06
1812	Nuclear	1092	76.78	398.07
1905	Gas-CC	297.5	31.56	72.96
1921	Nuclear	1092	76.78	398.07
1926	Wind	200	0	109.35
1935	PV	150	0	62.06
1965	Wind	200	0	109.35
2013	PV	150	0	62.06
2014	Gas-CC	297.5	31.56	72.96
2018	Wind	200	0	109.35
2030	Gas-CT	212.5	48.25	66.64
2042	Hydro	99	0	65.00

TABLE V. CANDIDATE STORAGE DEVICES DATA

Bus	Pmax (MW)	Capacity (MWh)	Charging/Discharging Efficiency (%)	Annual Investment Cost (Million $)
67	100	400	90	60
73	100	400	90	60
98	100	400	90	60
205	100	400	90	60
583	100	400	90	60
667	100	400	90	60
1462	100	400	90	60
1485	100	400	90	60
1732	100	400	90	60
1999	100	400	90	60

TABLE VI. SCENARIOS FOR THE PLANNING HORIZON 2030

Scenarios	Load Growth	Fixed Retirement	Regulation
S1: Reference	10%	Coal (73%), Gas (18%) *	No renewable mandates
S2: Environmental Regulations	Same as Reference	Same as Reference	Carbon Tax ($50/ton)
S3: Aggressive Retirement of Thermal Units	Same as Reference	Coal (100%), Gas (50%)	Same as Reference
S4: High Load Growth	20%	Same as Reference	Same as Reference

* Retirement by 2030 targeted by ERCOT [22].

After running both GEP and GTEP for all four scenarios, the below optimal solutions are obtained by JHSMINE. Annual system operation cost and the amount of load that will be shed in the peak load hour are shown in Fig. 4, while Fig. 5 depicts the annual investment cost for each of the four scenarios. Fig. 6 shows the overall annual cost (i.e., operation cost plus total investment cost), and selected assets are presented in Table VII.

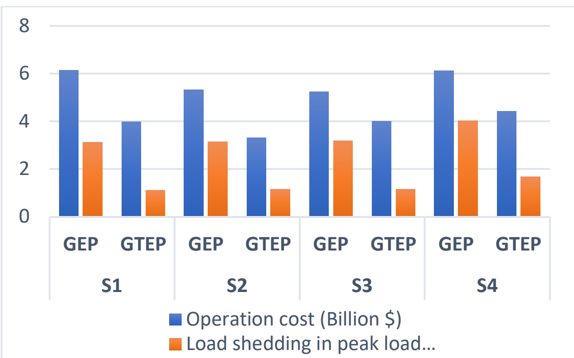

Fig. 4. Annual operation cost and load shedding for GEP vs. GTEP.

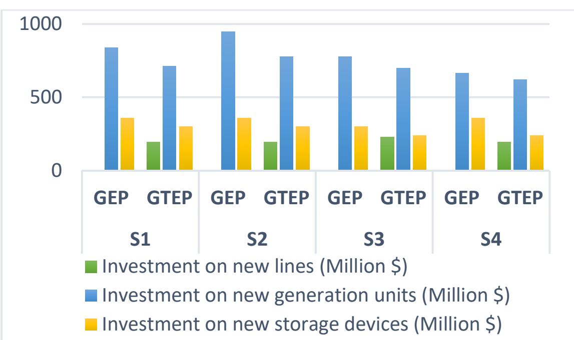

Fig. 5. Annual investment cost for GEP vs. GTEP.

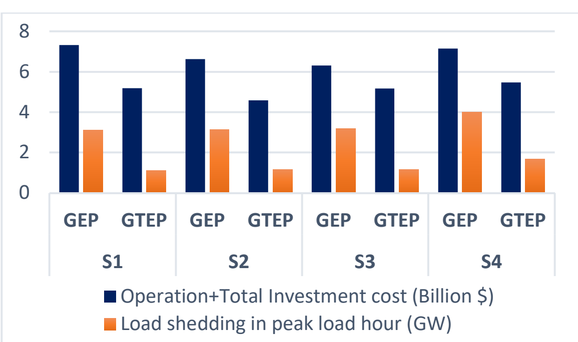

Fig. 6. Annual overall cost (operation plus investment costs) and load shedding for GEP vs. GTEP.

TABLE VII. SELECTED LINES, GENERATING UNITS, AND STORAGE DEVICES.

Scenarios	Model	Selected Transmission Lines	Selected Generating Units	Selected Storage Devices
S1	GEP	-	1, 2, 4, 10, 13, 16-19, 22-24,	2, 3, 6, 7, 9, 10
	GTEP	**1, 3-6, 8-10, 14, 18, 19, 21, 23**	4, **13**, 16-**19**, **22-24**, 33	**3**, 6, **8-10**
S2	GEP	-	1, 2, 4, 10, 13, 16-19, 22-24, 33	2, 3, 6, 7, 9, 10
	GTEP	**1, 3-6, 8-10, 14, 18, 19, 21, 23**	4, 10, **13**, 16-**19**, **22-24**, 33	**3**, 6, **8-10**
S3	GEP	-	2, 4, 10, 13, 16, 18, 19, 22-24, 33	2, 6, 7, 9, 10
	GTEP	**1**, **3**, 4, **6**, **8-10**, 12, **14**, **18-21**, **23**	4, 7, **13**, **18**, **19**, **22-24**, 33, 22-24	**3**, **8-10**
S4	GEP	-	4, 10, 13, 16-19,	2, 3, 6, 7, 9, 10
	GTEP	**1, 3-6, 8-10, 14, 18, 19, 21, 23**	10, **13**, 16-**19**, **22-24**, 29	**3**, **8-10**

From Fig. 4, it can be seen that both annual operation cost and load shedding decrease when the GTEP is considered instead of GEP. Comparing the scenarios, scenario S2, in which environmental regulations are enforced by a high carbon tax, results in a decrease in operating cost in both GEP and GTEP models compared to S1 (baseline) while the load shedding remains almost unchanged. The reason is revealed in Fig. 5 which shows that the investment in new generating units increases from **S1** to **S2**.

It can be seen in Fig. 5 that for all four scenarios the investment in new transmission lines alleviates the investments in new generation units and storage devices. To find out if the investment decisions suggested by GTEP are actually more beneficial or not, one can refer to Fig. 6 in which it is clearly illustrated that, regardless of which future scenario will happen, the overall cost of the system (i.e., operation plus investments costs) is much lower when the GTEP is considered instead of GEP. Furthermore, regardless of which future scenario will happen, the load shedding in peak load hour is also lower when the GTEP solution is considered (see Fig. 6). Obtaining a lower system cost with lower load shedding is the absolute reason that system planners should consider transmission expansion planning simultaneously with the resource expansion planning.

As bolded in Table VII, some new transmission lines, generating units, and storage devices are selected by the GTEP model in all four scenarios. These new assets that are robust to future scenarios can be seen as the best decisions for the system expansion. As shown in Table VII, more of the selected transmission lines and storage devices are robust to future scenarios, while a few selected generating units are insensitive to future scenarios. In other words, for this test system, the generation expansion decisions are scenario-dependent, while transmission and storage expansion decisions are mostly scenario-independent.

IV. DISCUSSION AND CONCLUSION

In this paper, we used the power system expansion planning tools developed by Johns Hopkins University (i.e., JHSMINE) to perform two studies on a large-scale ERCOT-like test system with 2,103 buses and 3,330 transmission lines.

In the first study, we quantify the economic benefit of optimization-based TEP over the approach of screening individual candidate lines. It is numerically illustrated that the benefit of annual operation cost for optimization-based TEP is more than twice that of a heuristic (greedy) screening procedure.

The second study is about the comparison between the solutions of resource-only expansion planning with those of joint resource and transmission expansion planning considering four future scenarios representing uncertainties that exist in emission reduction policies and forecasted demand. Considerable reductions in both system overall cost (i.e., operation plus investment costs) and load shedding during peak hour are observed when the solutions of joint resource and transmission expansion planning are considered. These reductions, which are observed in all four scenarios, are a clear sign of the necessity of performing transmission expansion planning simultaneously with resource expansion planning. Furthermore, numerical case studies show that for this test system, the generation expansion decisions are strongly scenario-dependent, while transmission and storage expansion decisions are mostly scenario-independent.

Acknowledgment

This research was primarily supported by the Grid Modernization Initiative of the U.S. Department of Energy (DOE) as part of its Grid Modernization Laboratory Consortium, a strategic partnership between DOE and the national laboratories to bring together leading experts, technologies, and resources to collaborate on the goal of modernizing the nation's grid. Funding was provided by the Office of Electricity, Office of Energy Efficiency and Renewable Energy, Wind Energy Technologies Office, Water Power Technologies Office, and the Office of Nuclear Energy.

Partial support was also provided by the Yale-JHU SEARCH (Solutions for Energy, Air, Climate, and Health) Center, funded under Assistance Agreement No. RD835871 awarded by the U.S. Environmental Protection Agency (EPA) to Yale University. It has not been formally reviewed by EPA.

The views expressed in this document are solely those of the authors and do not necessarily reflect those of the DOE, EPA, or the U.S. Government. EPA does not endorse any products or commercial services mentioned in this publication.

References

[1] A. J. Conejo, L. Baringo, S. J. Kazempour, and A. S. Siddiqui, *Investment in Electricity Generation and Transmission* (Springer International Publishing). 2016.

[2] M. Mehrtash, B. F. Hobbs, and Y. Cao, "A Large-Scale Test System for Transmission Expansion Planning with AC Networks Model," in *IEEE Texas Power and Energy Conference (TPEC)*, 2022, pp. 1-5: IEEE.

[3] R. Hemmati, R. A. Hooshmand, and A. Khodabakhshian, "Comprehensive review of generation and transmission expansion planning," *IET Generation, Transmission & Distribution,* vol. 7, no. 9, pp. 955-964, 2013.

[4] ERCOT, "Long-Term West Texas Export Study," January 2022, Available: https://www.ercot.com/files/docs/2022/01/14/Long-Term-West-Texas-Export-Study-Report.pdf.

[5] R. Romero, A. Monticelli, A. Garcia, and S. Haffner, "Test Systems and Mathematical Models for Transmission Network Expansion Planning," *IEE Proceedings-Generation, Transmission and Distribution,* vol. 149, no. 1, pp. 27-36, 2002.

[6] M. Rider, A. Garcia, and R. Romero, "Power System Transmission Network Expansion Planning Using AC Model," *IET Generation, Transmission & Distribution,* vol. 1, no. 5, pp. 731-742, 2007.

[7] M. Mehrtash and Y. Cao, "A New Global Solver for Transmission Expansion Planning With AC Network Model," *IEEE Transactions on Power Systems,* vol. 37, no. 1, pp. 282-293, 2022.

[8] M. Mehrtash, A. Kargarian, and A. J. Conejo, "Graph-Based Second-Order Cone Programming Model for Resilient Feeder Routing using GIS Data," *IEEE Transactions on Power Delivery,* vol. 35, no. 4, pp. 1999 - 2010, 2020.

[9] J. D. McCalley and V. Krishnan, "A survey of transmission technologies for planning long distance bulk transmission overlay in US," *International Journal of Electrical Power & Energy Systems,* vol. 54, pp. 559-568, 2014.

[10] M. Mehrtash, A. Kargarian, and M. Rahmani, "Security-Constrained Transmission Expansion Planning using Linear Sensitivity Factors," *IET Generation, Transmission & Distribution,* vol. 14, no. 2, pp. 200-210, 2019.

[11] R. Mahroo, A. Kargarian, M. Mehrtash, and A. Conejo, "Robust Dynamic TEP with an N − c Security Criterion: A Computationally Efficient Model," *IEEE Transactions on Power Systems,* 2022.

[12] J. L. C. Meza, M. B. Yildirim, and A. S. Masud, "A model for the multiperiod multiobjective power generation expansion problem," *IEEE Transactions on Power Systems,* vol. 22, no. 2, pp. 871-878, 2007.

[13] E. B. Cedeño and S. Arora, "Integrated transmission and generation planning model in a deregulated environment," *Frontiers in Energy,* vol. 7, no. 2, pp. 182-190, 2013.

[14] V. Krishnan, J. Ho, B. F. Hobbs, A. L. Liu, J. D. McCalley, M. Shahidehpour, and Q. P. Zheng, "Co-optimization of electricity transmission and generation resources for planning and policy analysis: review of concepts and modeling approaches," *Energy Systems,* vol. 7, no. 2, pp. 297-332, 2016.

[15] J. Aghaei, N. Amjady, A. Baharvandi, and M.-A. Akbari, "Generation and Transmission Expansion Planning: MILP–Based Probabilistic Model," *IEEE Transactions on Power Systems,* vol. 29, no. 4, pp. 1592-1601, 2014.

[16] M. Mehrtash and A. Kargarian, "Risk-Based Dynamic Generation and Transmission Expansion Planning with Propagating Effects of Contingencies," *International Journal of Electrical Power & Energy Systems,* vol. 118, p. 105762, 2020.

[17] H. Mazaheri, A. Abbaspour, M. Fotuhi-Firuzabad, H. Farzin, and M. Moeini-Aghtaie, "Investigating the impacts of energy storage systems on transmission expansion planning," in *2017 Iranian Conference on Electrical Engineering (ICEE)*, 2017, pp. 1199-1203: IEEE.

[18] X. Zhang and A. J. Conejo, "Coordinated investment in transmission and storage systems representing long-and short-term uncertainty," *IEEE Transactions on Power Systems,* vol. 33, no. 6, pp. 7143-7151, 2018.

[19] B. F. Hobbs, "Optimization methods for electric utility resource planning," *European Journal of Operational Research,* vol. 83, no. 1, pp. 1-20, 1995.

[20] L. L. Taylor, S. T. Lee, J. E. Sustman, G. L. Ganz, and D. C. Maschoff, "A screening model for utility strategic planning," *IEEE Transactions on Power Apparatus and Systems,* no. 8, pp. 4093-4103, 1981.

[21] M. Mehrtash, "Optimal and Efficient Decision-Making for Power System Expansion Planning," ECE, Louisiana State University, 2019.

[22] "2021 State of the Market Report for the ERCOT Electricity Markets," May 2022, Available: https://www.potomaceconomics.com/wp-content/uploads/2022/05/2021-State-of-the-Market-Report.pdf.

[23] P. Cuffe and A. Keane, "Visualizing the electrical structure of power systems," *IEEE Systems Journal,* vol. 11, no. 3, pp. 1810-1821, 2015.

[24] B. F. Hobbs, Q. Xu, J. Ho, P. Donohoo, S. Kasina, J. Ouyang, S. W. Park, J. Eto, and V. Satyal, "Adaptive transmission planning: implementing a new paradigm for managing economic risks in grid expansion," *IEEE Power and Energy Magazine,* vol. 14, no. 4, pp. 30-40, 2016.

[25] Q. Xu and B. F. Hobbs, "Transmission Planning and Co-optimization with Market-Based Generation and Storage Investment," in *Transmission Network Investment in Liberalized Power Markets*: Springer, 2020, pp. 201-236.

[26] (February 2020). *Julia*. Available: https://julialang.org/

[27] (February 2020). *JuMP*. Available: https://jump.dev/JuMP.jl/stable/

[28] (February 2020). *CPLEX*. Available: https://www.ibm.com/products

[29] S. Blumsack and M. Ilić, "The braess paradox in electric power systems," *Working Paper,* 2006.