

MULTI-OBJECTIVE STOCHASTIC EXPANSION PLANNING OF MULTI-CARRIER ENERGY DISTRIBUTION NETWORKS CONSIDERING CUSTOMER-OWNED DG UNITS

Mohammad JOOSHAKI

Sharif University of Technology – Iran
jooshaki_mohammad@ee.sharif.edu

Hossein FARZIN

Shahid Chamran University of
Ahvaz – Iran
Farzin@scu.ac.ir

Ali ABBASPOUR

Sharif University of Technology – Iran
abbaspour@sharif.ir

Matti LEHTONEN

Aalto University – Finland
matti.lehtonen@aalto.fi

Mahmud FOTUHI-FIRUZABAD

Sharif University of Technology – Iran
fotuhi@sharif.edu

ABSTRACT

In this paper, a multi-objective framework is proposed for expansion planning of energy hubs, natural gas and electricity distribution systems considering the uncertainties of renewable sources and demand. The aim is to reduce total investment and operation costs through coordination among different stakeholders. In this regard, planning problems from each stakeholder's point of view are modeled as individual optimization problems. Subsequently, a multi-objective framework for optimization of conflicting interests of different stakeholders is extracted and solved using the multi-objective genetic algorithm. The proposed model is applied to a multi-carrier energy distribution system and the obtained results are thoroughly discussed.

INTRODUCTION

Although widespread integration of various DG technologies in distribution networks promises a cost-efficient, reliable, and environment-friendly power system, it brings about several challenges for energy distribution system planners and operators. On the one hand, intermittent output power of non-dispatchable renewable energy sources (RES) has introduced new uncertainties to planning and operation studies [1], and on the other hand, installation of co- and tri-generation units has increased the interdependence of natural gas and electricity distribution networks [2]. In addition, widespread integration of non-dispatchable DGs can cause serious challenges for electricity distribution companies, e.g. increasing initial and long-term network investment, as well as network operation and maintenance costs [3]-[5]. Furthermore, high penetration level of gas-fired units can place a costly burden on natural gas distribution companies. This calls for new as well as efficient tools for addressing the interdependency between different energy infrastructures and also inherent uncertainties of RES. Recently, the effects of such uncertainties have been of great interest in many publications in the field of electricity distribution planning [6]-[9], and co-planning studies [10]-[13]. In [5], a two-stage framework is proposed for stochastic expansion planning of electricity distribution networks considering uncertainty of renewable generations, electric vehicles, and electricity demand.

Active distribution system planning considering renewable DG integration together with conventional options for network expansion is presented in [7], where uncertainties of demand and output power of DG units are modelled through multiple scenarios. Employing polyhedral uncertainty sets, authors in [8] characterized the uncertainties of electricity loads and wind DGs and developed an adaptive robust distribution expansion planning framework. A novel hybrid-heuristic technique is presented in [9] to attain the multi-stage distribution system investment decisions taking into account the uncertainty of RES and flexibility options.

Optimal scheduling of natural gas and electricity distribution systems with electricity-to-gas technology as well as gas-fired DG units is performed in [10] to minimize the operating cost of the integrated energy distribution system. An alternating direction method of multipliers (ADMM)-based model is proposed in [11] to develop optimal day-ahead scheduling model for electricity and natural gas distribution networks considering the uncertainties of generating units, as well as electricity and natural gas demands. Long-term planning of natural gas-fired DG units and Gas distribution network under uncertain demand is carried out in [12] using a stochastic optimization approach. Integrated expansion planning of natural gas and electricity distribution grids considering natural gas and electricity power demand uncertainties is performed in [13], where both networks are planned as a unified system.

However, little attention has been paid to the multi-objective collaborative planning studies of natural gas and electricity distribution networks, and customer-owned DGs considering the uncertainties of RES.

Motivated by the aforementioned points, this paper aims to propose a comprehensive framework for collaborative planning of natural gas and electricity distribution networks taking into account the integration of various DG technologies modeled as energy hubs (EH), and load and RES uncertainties.

METHODOLOGY

This paper proposes a general framework for co-planning studies of natural gas and electricity distribution systems in presence of various customer-owned DG technologies. In this framework, concept of energy hub is employed to

model the impacts of DG units and energy demands on both electricity and gas networks. Hence, EH operators, and electricity and natural gas distribution companies are considered as the main stakeholders of this study. Since these entities have different interests, a multi-objective (MO) formulation should be formed to obtain a compromise between their conflicting objectives [14], [15]. As the current algorithms for optimizing MO problems require a considerable number of iterations, objective function evaluation times and accuracy of the obtained results are of critical importance. Therefore, aimed to find optimal expansion plans, mathematical models of the planning problem from each stakeholder's viewpoint are extracted, and are linearized in order to reduce the computation time as well as to guarantee the achievement of global optimum solution. In this regard, linearized formulations for natural gas expansion planning problem is derived, and a linear stochastic model is employed to deal with energy demand and RES uncertainties in the planning and operation studies of EHs. Moreover, the model presented in [16] is adopted to linearize electricity network expansion planning problem. Based on the results of such studies, NSGAI, which is a multi-objective optimization algorithm, is applied to generate the Pareto set of optimal planning solutions, as depicted in Fig. 1.

According to this figure, maximum permissible power at the connection points of EHs to the electricity distribution network are considered as candidate solutions of the MO optimization problem. Accordingly, the NSGAI tries to obtain the Pareto front through solving the three optimization problems for each candidate solution. In this regard, EHs stochastic planning and operation problem considering the electricity grid connection limits determined by the NSGAI, is carried out first. This provides the total planning and operating cost of the EHs,

as one of the three objective functions, as well as the maximum required connection capacities of each EH to the natural gas and electricity grids. Subsequently, electricity and natural gas planning problems are solved based on the obtained connection capacities from the previous step, i.e. EHs planning. Running these optimization problems, the other two objectives, i.e. expansion costs of electricity and natural gas networks, are attained. These outcomes are then analyzed to check their Pareto optimality. Finally, as the convergence criteria are satisfied [17], the set of Pareto optimal solutions is achieved. This Pareto set provides various alternatives for planning of the integrated energy system from which, the most suitable solution can be chosen.

PROBLEM STRUCTURE

As previously mentioned, integrated energy distribution system planning model is comprised of three parts, which their associated formulations are elaborated in the following.

Energy hubs planning model

As previously mentioned, in this paper, demands of energy carriers in different nodes of electricity and natural gas distribution networks, as well as customer-owned DG units are modeled as energy hubs. As depicted in Fig. 2, each EH is comprised of transformer, combined heat and power (CHP) unit, wind turbine, photovoltaic (PV) panel, and heat furnace. As illustrated, electricity demand of energy hub, $D_{n,t,s,ll}^E$, is served by the local electricity generation units, i.e. CHP, PV panel and wind turbine, as well as the power from electricity grid. Moreover, according to the arrows, which represent power flow direction, the injection of extra local generation to the electricity network is also taken into account. Furthermore, the heat demand is met through furnace and recovered heat from CHP unit.

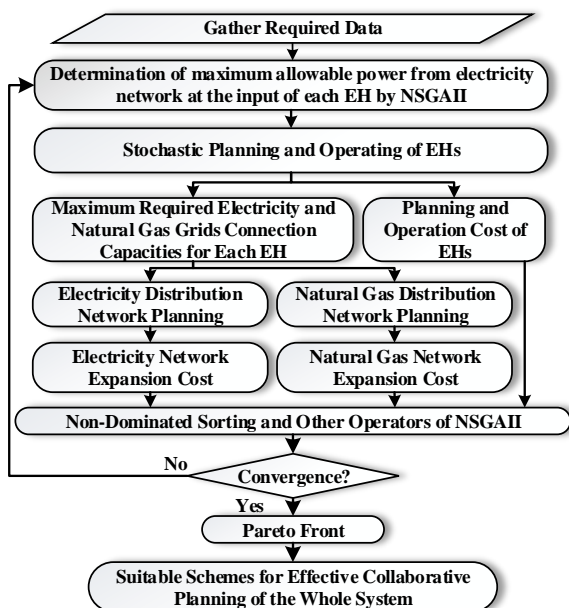


Fig. 1. Proposed multi-objective planning framework.

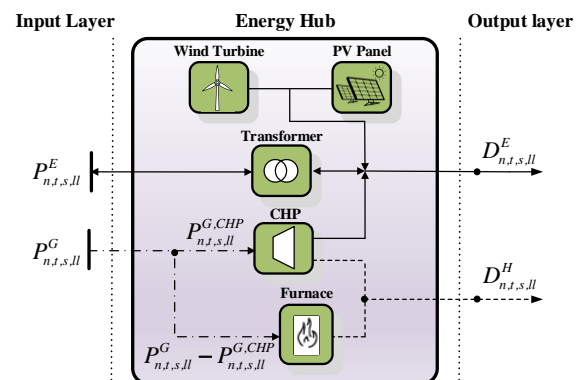


Fig. 2. Structure of the considered energy hub.

The goal of stochastic EHs planning optimization problem is to minimize total present value of the investment and expected operating costs of all EHs over the planning horizon, T , as given by (1):

$$\min \text{OF}^{EH} = \sum_{n=1}^{N_{EH}} \sum_{t=1}^T \left(\delta_t^{Inv} \text{Inv}_{n,t} + \sum_{s=1}^{N_{Sc}} p_s \sum_{l=1}^{N_L} \delta_t^{Op} \text{Op}_{n,t,s,l} \right) \quad (1)$$

where N_{EH} , N_{Sc} and N_L are respectively the number of EHs, scenarios, and load levels, δ_t^{Inv} and δ_t^{Op} are present value conversion factors for investment and operating costs, respectively, and p_s is occurrence probability of scenario s . The investment cost, $\text{Inv}_{n,t}$, is a function of installed capacities of CHP, furnace, wind turbine, photovoltaic panel, and transformer. Furthermore, $\text{Op}_{n,t,s,l}$ is operating cost of n^{th} EH at scenario s and load level l in year t , and is a function of imported electric power from network, local power production of solar and wind units, imported gas, electricity and gas prices, and energy demand at different timeslots of various scenarios. The considered scenarios correspond to different possible states for daily patterns of electricity and heat demands, as well as power production patterns of renewable DG units, i.e. wind turbines and PV panels.

Moreover, EHs planning problem is subject to sets of equality and inequality constraints, which correspond to power balance within energy conversion devices, and their capacity limits as well as the connection capacity limits. The latter determine the capacity of the EHs' connections to the electricity grid, which are imposed based on the candidate solutions from NSGAI algorithm (see Fig. 1). Solving this optimization problem, optimal capacities of EHs components as well as the amount of electricity power exchanged between each EH and electricity grid ($P_{n,t,s,l}^E$) (see Fig. 2), and also imported gas from the natural gas network ($P_{n,t,s,l}^G$) (see Fig. 2), are attained. The values of $P_{n,t,s,l}^E$ and $P_{n,t,s,l}^G$ are further used as the nodal demands of electricity and natural gas networks, based on which the expansion planning of these network are performed.

Gas Distribution Network Expansion Planning

This problem intends to determine the optimal plan for natural gas network expansion in anticipation of the predicted demands. In this respect, several expansion alternatives including reinforcement of existing pipelines and city-gates as well as construction of new ones are considered in this paper. Accordingly, solution of this planning problem provides optimal arrangements for reinforcement and construction of pipelines and city-gates, which minimizes total present value of the investment and operating costs of the natural gas distribution network over the planning horizon. Hence, mathematical model of the problem can be expressed as follows:

$$\min \text{OF}^{GP} = \sum_{t=1}^T \left(\sum_{p=1}^{N_p} \left(\delta_t^{Inv} \text{Inv}_{p,t}^{Pi} + \delta_t^{Op} \text{Op}_{p,t}^{Pi} \right) + \sum_{c=1}^{N_c} \left(\delta_t^{Inv} \text{Inv}_{c,t}^{Ci} + \delta_t^{Op} \text{Op}_{c,t}^{Ci} \right) \right) \quad (2)$$

where N_p , N_c are the number of pipelines and city gates, and Pi and Ci superscripts stand for pipeline and city gate. Investment costs are functions of reinforcement or construction actions performed on city-gates and pipelines. Moreover, operating costs includes costs

associated with the maintenance of pipelines and city-gates. This problem is also subject to various logical and technical constraints including radiality constraint, gas flow limits through pipelines and city-gates, maximum and minimum permissible nodal pressures, and nonlinear gas-flow equations [2]. In this paper, these equations are linearized using piece-wise linearization approach.

Electricity Distribution Network Expansion Planning

This problem generally aims to determine the optimal set of investment actions, which should be performed on feeders and substations, considering network constraints. By considering feeders and substations of electricity network as equivalents of pipelines and city-gates in gas distribution network, mathematical model of this problem is almost similar to the natural gas distribution network planning. In this context, electricity distribution expansion planning optimization problem can be formulated as (3).

$$\min \text{OF}^{EP} = \sum_{t=1}^T \left(\sum_{f=1}^{N_f} \left(\delta_t^{Inv} \text{Inv}_{f,t}^{Fe} + \delta_t^{Op} \text{Op}_{f,t}^{Fe} \right) + \sum_{s=1}^{N_s} \left(\delta_t^{Inv} \text{Inv}_{s,t}^{Su} + \delta_t^{Op} \text{Op}_{s,t}^{Su} \right) \right) \quad (3)$$

where N_f and N_s are the number of feeders and substations, respectively. $\text{Inv}_{f,t}^{Fe}$, $\text{Inv}_{s,t}^{Su}$ represent investments performed on feeder f and substation s at time stage t , respectively. Operating costs of feeders and substations are also denoted as $\text{Op}_{f,t}^{Fe}$, $\text{Op}_{s,t}^{Su}$, respectively.

This optimization problem should be solved subject to various constraints including budget limitation, feeders and substations capacity limits, nodal voltage limits, radiality constraint, as well as power flow equations. It is worth noting that this problem is non-linear in nature, mainly due to electricity power-flow equations. Hence, the approximate power flow model presented in [16] is employed in this paper to linearize electricity network planning problem.

NUMERICAL STUDY

In this section, multi-objective stochastic planning of EHs, electricity and natural gas networks is demonstrated via implementation on an 18-bus test energy distribution grid. This integrated system has 16 EHs, 2 sub-transmission substations, and 2 city-gates, as depicted in Fig. 3. Each EH is designed based on the structure depicted in Fig. 2. Moreover, various options for the network expansion includes reinforcement of substations, city-gates, existing feeders and pipelines, as well as construction of candidate feeders and pipelines. In other words, outcomes of the optimal electricity and natural gas networks planning problems determine the optimal set of reinforcement and construction actions that should be performed on these networks. In this respect, two alternatives are considered for reinforcement of each of the existing assets, and three various options are assumed for construction of each of the candidate assets. These alternatives differ from each other in terms of investment and operating costs, as well as

technical features such as capacity, impedance (for electricity network assets), and pressure drop factors (for gas network assets).

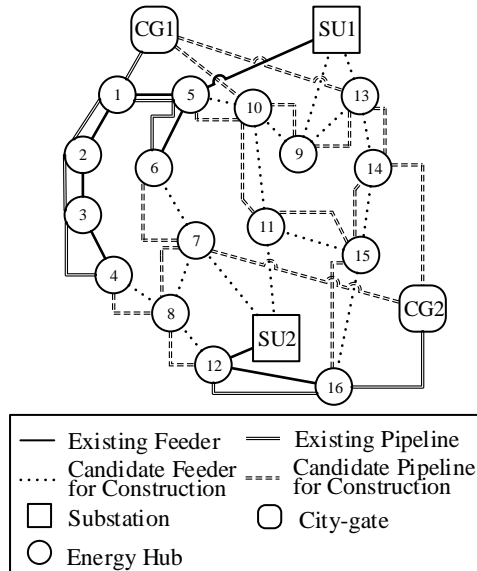


Fig. 3. Schematic diagram of the 18-node integrated natural gas and electricity distribution system.

In order to capture the uncertainty of renewable sources and demand, six, four and two scenarios are considered for hourly wind speed, solar radiation as well as heat and electricity demand patterns, respectively. Moreover, a three-year planning horizon is assumed in the simulations. It is worth mentioning that the present value factors are calculated based on infinite perpetuity approach as in [1]. In this context, it is assumed that each asset is replaced with the same one after reaching its lifetime, and operating cost of the last year of the planning horizon is repeated in the following years.

Base Case: Passive Energy System Planning

In this case, no DG investments are considered. Therefore, EH costs are only comprised of the imported electricity and natural gas costs for supplying electricity and heat demands. The obtained results are summarized in Table 1.

Table 1. Outcomes for the base case.

	OF ^{EH}	OF ^{EP}	OF ^{GP}	Total
Cost (M\$)	55.313	30.468	22.087	107.8680

Multi-objective Active Energy System Planning

The set of Pareto optimal solutions obtained from the proposed MO framework are depicted in Fig. 4. It should be noted that the MO problem is solved using the *gamultiobj* function in MATLAB software. As can be seen, there is a tradeoff between different objectives, where expansion costs of electricity and gas networks (corresponding to the horizontal axes in Fig. 4) will only decrease if EH operation and investment costs are raised (corresponding to the vertical axis).

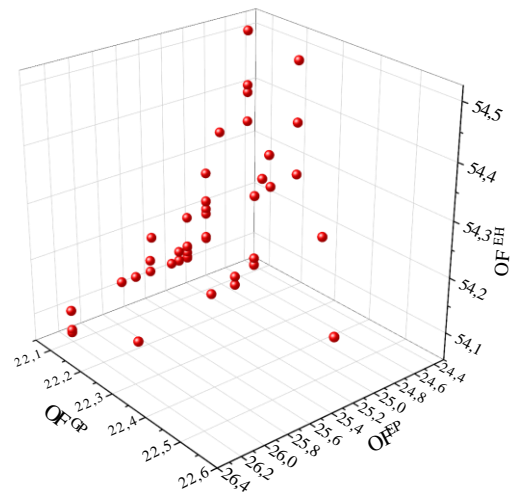


Fig. 4. Pareto optimal solutions (All costs are in M\$).

Table 2. Comparison of four Pareto optimal solutions (All costs are in M\$).

	OF ^{EH}	OF ^{EP}	OF ^{GP}	Total
Solution I	54.061	26.176	22.088	102.325
Solution II	54.402	24.502	22.237	101.141
Solution III	54.141	25.452	22.087	101.680
Solution IV	54.333	24.503	22.088	100.922

Different cost terms for four sample solutions from the obtained Pareto optimal set are reported in Table 2 for further analysis. Solution I is the one with minimum EH operation and investment costs. Note that this solution corresponds to the traditional case, where EH planning is optimized independently, without considering the distribution system costs or preferences. In other words, in the first step, DG owners optimize their expansion plans based on their own costs/benefits. Subsequently, electricity and gas distribution companies determine their network expansion plans so that EH demands are fully satisfied. This will result in high network expansion costs. In addition, total system cost has the maximum value among the four solutions, as can be seen in the Table. On the other hand, Solution II has the minimum electricity network expansion costs. Comparing with Solution I, it can be seen that a slight increase in EH and gas network costs has resulted in a significant reduction in the electricity network costs. As a result, total costs are also significantly lower than Solution I; similarly, Solution III is the solution with minimum gas network expansion costs. In this solution too, reduction of network costs is dominant, and total costs have decreased in comparison with Solution I.

Among the solutions, Solution IV has the lowest total costs, while electricity and gas network expansion costs are slightly higher than that of Solutions II and III. In other words, this Solution can be considered as an effective tradeoff among the three objectives, which is the best solution from social welfare point of view. Moreover, it can be concluded that traditional case, in which network

reinforcement is optimized after planning of DG units has the highest total costs. This fact highlights the importance of collaborative planning in such integrated systems. On the other hand, from comparison with the Base Case, it can be observed that integration of DG units has significantly reduced electricity network expansion costs. Moreover, cost of supplying electricity and heat demands have decreased as a consequence of DG integration, as can be confirmed from the reported EH costs.

CONCLUSION

In this paper, multi-objective expansion planning of autonomous DG units, natural gas and electricity distribution systems is studied. In order to efficiently capture mutual effects of various energy carriers on demand supply, energy hub concept is utilized. Optimal planning problems from viewpoint of the three stakeholders, i.e. EHs owners, as well as electricity and natural gas distribution companies, are derived. Subsequently, multi-objective genetic algorithm is deployed to reach the Pareto optimal solutions. The proposed model is then applied to the 18-node energy distribution system and the obtained results are discussed in detail. The outcomes show the importance of collaborative planning among DG owners, electricity and natural gas distribution companies in reaching an efficient solution from the social welfare point of view.

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