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Stochastic Expansion Planning of Gas and Electricity Networks: A Decentralized-Based Approach

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Abstract

This paper introduces a stochastic decentralized model for coordinating expansion of gas and electricity networks to tackle the interdependency between electricity and gas infrastructures and deal with different challenges incorporated in such co-expansion problem. Different uncertainties including wind power output, interest rate and load growth are considered to have a holistic stochastic approach. Regulatory policy for restricting capacity additions in terms of new renewable installations as well as demand response program are also incorporated in this study to examine the effect of regulatory frameworks and end-users on expansion planning of gas and electricity networks. Moreover, the effect of land area limitations is investigated in expansion plans as a practical consideration. Alternating direction method of multipliers is used as a solution methodology to coordinate expansion of gas and electricity networks with a minimum data exchange. To evaluate the efficiency of the proposed method, results are examined on a realistic case study in Khorasan province of Iran representing high penetration level of gas consuming power plants.

Keywords: Integrated energy systems, expansion planning, gas-electricity, stochastic, alternative direction method of multipliers**.**

Nomenclature

Indices and Sets

i, j	Index for gas nodes
m, n	Index for electricity buses
$\widehat{m}$	Index of electricity buses with wind power generators
ω	Index of scenarios
t	Index of load period (off-peak, mid, peak)
d	Index of days
y	Index of years
$h/\hat{h}$	Index for all/gas consuming generation units
k	Index of repetition
im	Index for linking bus m of electricity system to node i of gas system
$\mathcal{N}/\mathcal{B}$	Set of nodes/buses of gas/electricity system
$\mathcal{TL}$	Set of transmission lines
$\mathcal{PL}/\mathcal{PL}^A/\mathcal{PL}^p$	Sets of all/active/passive pipelines
$\mathcal{T}$	Set of daily load periods
Ω	Set of scenarios
$\mathcal{H}$	Set of all generation units

Variables

$Q_{f_{i,j,y,d,\omega}}$	Gas flow of pipeline *ij* on day *d* of year *y* in scenario ω in MSCMD
$Q_{S_{i,y,d,\omega}}$	Gas injection at node *i* in MSCMD
$Q_{l_{i,y,d,\omega}}^{pp}$	Gas demand of GCPPs at node *i* in MSCMD
$Q_{l_{i,y,d,\omega}}^{comp}$	Gas loss of compressor at node *i* in MSCMD
$Q_{r_{i,y,d,\omega}}$	Curtailed gas demand at node *i* in MSCMD

$pr^{g}_{i,y,d,\omega}/\pi^{g}_{i,y,d,\omega}$	Gas pressure in bar/squared pressure in bar^2
$FC_{m,h,y,d,t,\omega}$	Fuel consumption of unit *h* in power plant of bus *m* in MSCM per hour
$P_{f_{m,n,y,d,t,\omega}}$	Power flow of line *mn* in MW
$P_{s_{m,h,y,d,t,\omega}}$	Generation power of unit *h* of bus *m* in MW
$P_{W_{m,y,d,t,\omega}}$	Generation power of wind farm of bus *m* in MW
$P^{E}_{l_{m,y,d,t,\omega}}$	Effective load of bus *m* in MW
$P^{-}_{DR_{m,y,d,t,\omega}}/P^{+}_{DR_{m,y,d,t,\omega}}$	Decrement/increment DRP of bus *m* in MW
$u^{-}_{DR_{m,y,d,t,\omega}}$ $/u^{+}_{DR_{m,y,d,t,\omega}}$	Binary variable indicating decrement/increment DRP of bus *m*
$\theta_{m,y,d,t,\omega}$	Voltage angle of bus *m* in Rad
$P_{r_{m,y,d,t,\omega}}$	Curtailed electric power at bus *m* in MW
$u^{Pipe}_{ij}/u^{trans}_{mn}/u^{gen}_{mh}$ $/u^{W}_{m}$	Binary variable indicating existence of pipeline *ij*/transmission line *mn*/generating unit *h* of bus *m*/wind farm of bus *m*
μ_{im}	Lagrangian multiplier of nodal balance equation at node *i*

Parameters

K^{pipe}_{ij}	Weymouth constant in MSCMD/bar
R^{comp}_{ij}	Pressure ratio in active pipelines
$Q^{Npp}_{l_{i,y,d,\omega}}$	Gas demand of non-power plant loads at node *i* in MSCMD
$\int^{comp}_{ij}$	Constant defining compressor gas consumption in active pipeline *ij* in bar^{-1}
$\lambda^{gas}_{l_{i,y,d,\omega}}$	Gas price at node *i* \$/MSCM

$\lambda_{r_{i,y,d,\omega}}^{gas}$	Gas curtailment price at node *i* \$/MSCM
L_{ij}^{Pipe}	Length of pipeline *ij* in km
A_{ij}^{Pipe}	Diameter of pipeline *ij* in inch
$P_{s_{m,h}}^{R}$	Rated power of unit *h* of bus *m* in MW
$P_{w_m}^{R}$	Rated power of wind farm of bus *m* in MW
$\overline{P^W}$	Upper limit for new wind farm installations in MW
$P_{l_{m,y,d,t,\omega}}$	Power demand at bus *m* in MW
$\lambda_{r_{m,y,d,t,\omega}}^{elec}$	Load curtailment price at bus *m* in \$/MW
$\lambda_{m,h,y,d,\omega}^{FC}$	Fuel price of unit *h* of bus *m* in \$/ MSCMD
$\lambda_{m,y,d,t,\omega}^{DR}$	Incentive price for participation in load-shedding program in \$/MW
y_{mn}	Series admittance of line *mn*
P_b	Base of power in MW
GHV_h	Gross heating value of fuel in unit *h* in MMBTU/MSCM
$cost_{ij}^{Pipe}/cost_{mn}^{trans}$ $/cost_{mh}^{gen}/cost_{m}^{W}$	Investment cost of pipeline *ij* (k\$/inch-km)/transmission line *mn* (k\$/km)/generation unit *h* of bus *m* (k\$/MW)/ wind farm of bus *m* (k\$/MW)
T	Planning period
$T^t/T^g/T^p$	Transmission/Generation/Pipeline useful life
d_t	Duration of period t
$\tilde{\imath}_{\omega}$	Interest rate in scenario ω
ρ	Penalty factor
$\overline{A_m^G}$	Available capacity according to the specified land for GCPPs in MW

$\overline{A^{W}_{\hat{m}}}$	Available capacity according to the specified land for wind turbines in MW
$\overline{A^{P}_{\iota J}}$	Available capacity according to the specified land for pipelines in MSCMD
$(\frac{P}{A},\tilde{\imath}_{\omega},T)$/ $(\frac{A}{P},\tilde{\imath}_{\omega},T)$/ $(\frac{P}{F},\tilde{\imath}_{\omega},T)$	Time value of money that converts an annual value to its equivalent present value/ a present value to its equivalent annual value/ and a future value to its equivalent present value over period *T* with interest rate $\tilde{\imath}_{\omega}$

1. Introduction

Natural gas is a clean and high-efficient source of energy and as an advantage, gas-fired power plants have higher efficiency, lower capital cost, and lower carbon emissions than the other types of fossil-driven plants [1]. Gas-fired power plants, as a type of gas consuming power plants, also offer a flexible operation to mitigate growing renewable fluctuations [2].

With the increased penetration of gas consuming power plants (GCPP) in the generation mix of power systems, coordinated expansion of electricity and gas infrastructures becomes a majority. On the other hand, it is shown in [3] that short-term uncertainties in renewables power production availability and long-term uncertainties in load forecast affects expansion planning of electricity system. Besides, [4] illustrates how demand response programs (DRPs) could modify demand profiles in integrated energy systems and facilitate energy management process. However, the uncertainties associated with renewables, load forecast, DRP and interest rates would affect both gas and electricity systems. Within this context, this paper addresses the coordinated investment in gas and electricity infrastructures when gas and electricity networks have private owners. This model can guarantee feasible and economic operation of an integrated gas-electricity network while considering different uncertainties associated within the energy system. The model can analyze the trade-off between investment in transmission, generation, and pipeline installations.

In many countries gas and electricity networks are expanded and operated separately [5]. With the increasing dependency of gas and electricity networks, it is necessary to coordinate expansion of gas and electricity networks. Although central expansion planning of gas and electricity networks seems a good idea, it is not practical since gas and electricity network have independent operators. Usually, there is not a central entity that has technical knowledge and data about infrastructures of both gas and electricity networks. Engineers of an electricity network are well aware of the power system, have knowledge of electricity network expansion planning, and have access to the required data. However, they don’t have the required knowledge and data about the associated gas network. The same holds true for engineers of the gas network. Therefore, it is necessary to present a decentralized expansion planning model for coordinating gas and electricity networks with minimum requirements on data exchange.

In the existing literature, a number of approaches have been taken into account to model the joint gas-electricity expansion problem (GEEP). Integrated expansion planning of gas and electricity networks is accomplished in [1] using a centralized model where, authors employ a real world test case to examine the results. This method is further developed in [6] to analyze the effect of DRP on GEEP model. This method is also expanded to a leader-follower approach in [7] to coordinate the expansion planning of gas and electricity networks. In that paper, electricity network as a leader makes decision and gas network follows accordingly. Authors in [8] integrate the expansion planning of gas and electricity infrastructures via a multi-area and multi-stage model. This paper also considers liquefied natural gas and natural gas storages as a source of supply for gas network. A similar model that integrates gas and electricity systems in the distribution level is presented in [9]. Proposed model in [10] minimizes the expansion cost of gas and electricity systems as well as their operational cost considering facilities like compressors and storages for gas network, while, the model presented in [11] increases overall social welfare. In [11] the adaption cost to new conditions has been used to deal with uncertainties such as market prices. Similar model in [12] provides a centralized model for the expansion of large-scale systems where a three level framework solves the integrated expansion problem. A low-carbon oriented representation of expansion problem which considers profit-to-cost maximization as objective function, is introduced in [13]. In this model, market prices of gas and electricity are considered as different price scenarios. Authors in [14] study the expansion planning of electricity network in an integrated and restructured electricity and gas market. Planning model in [15] provides a system with optimal size, location and installation time of gas-electricity infrastructures based on feasibility and reliability criterions. An iterative process between gas and electricity systems in a combined gas-electricity market is illustrated in [16]. In [17] a robust model proposes an integrated expansion plan for electricity and natural gas networks considering grid resilience as a set of constraints. Authors in [18] use a two-stage stochastic framework to deal with uncertainties in demand growth. Proposed model in [19] provides an optimal plan for an energy hub consisted of combined heat and power, boiler, absorption chiller, compression chiller, electricity storage (Li-ion battery) and heat storage. It also takes energy supply reliability into account. A sequential solving procedure for expansion planning of gas-electricity system is introduced in [20]. Bi-directional energy conversion in gas-electricity expansion problem is formulated in [21] by a bi-level problem, in which the upper-level optimizes the expansion cost and the lower-level optimizes the operation cost. Presented model in [22], considers N-1 security and probabilistic reliability criterions in the centralized planning model of gas and electricity networks. Authors in [23] provide a chance-constrained model to manage uncertainties in demand while minimizing the expansion cost of electricity and gas networks. A multi-attribute expansion planning model of electricity and gas networks is introduced in [24] that considers electricity network expansion cost, gas network expansion cost, robustness and maximum regret in the decision making process of a central coordinator. Authors in [25] provide a dynamic co-planning model of electricity and gas networks while considering uncertainties of renewable energy resources. Optimal size of an electricity storage system as well as a combined heat and power device is obtained in [26] where contingency events are also investigated. Authors in [27] provide a robust model to coordinate day-ahead optimal scheduling of gas and electricity networks. In this model uncertainties in loads and renewable energies are incorporated in the optimization process. Proposed model in [28] develops an integrated planning approach to electricity and gas networks while considering uncertainties in renewable power, load growth and gas price.

Despite the centralized models of gas-electricity system, recently some researches have focused on decentralized optimization. In [5] alternating direction method of multipliers (ADMM) is used for synergistic operation of gas and electricity systems. Authors in [29], by using ADMM provide the scheduling of a joint gas-electricity system, considering bi-directional energy conversion in gas and electricity systems. Decentralized operation and coordinated energy flow in a multi-area integrated gas-electricity system is studied in [30]. However, decentralized expansion planning of gas and electricity networks is a gap in the existing literature.

The present work introduces a stochastic decentralized model for coordinating expansion planning of gas and electricity networks considering uncertainties. This model considers uncertainties in annual load growth, interest rate, and wind power generation. Regulatory policies of new renewable installations within the proposed realistic case study are implemented to see how regulatory policies can affect the GEEP. With the proposed GEEP model, capacity and location of new power plants, transmission lines and pipelines are determined. DRP is also investigated within the proposed GEEP model to have a holistic approach in the context of stochastic and decentralized modeling. ADMM is used to coordinate expansion planning of gas and electricity networks with minimum data exchange and preserve the privacy of gas and electricity private companies. Each operator separately makes decision for expansion of its subordinated subsystem. The main contributions of this paper are as follows:

- Expansion planning of gas and electricity networks is studied in an environment with different uncertainties.
- Regulatory framework of the proposed realistic case study is considered as constraints to evaluate the effect of regional policies on the proposed GEEP model.
- An ADMM-based decentralized modeling of GEEP is introduced to preserve the privacy of different energy parties.

This paper is structured as follows. Section 2 describes the proposed GEEP model and its related mathematical formulations. Under different scenarios, the proposed method is examined in Section 3 using a realistic case study in Khorasan province of Iran. Finally, the paper is concluded in Section 4.

2. Formulation of Expansion Planning Model

In the existing literature, coordinated expansion planning of an integrated gas-electricity energy system is solved from the viewpoint of a central decision maker. In the centralized model, the central decision maker collects detailed data of both gas and electricity networks and centrally allocates new expansion candidates for the entire integrated gas-electricity system. However, gas and electricity network operators are private companies without a data exchange mechanism. In this section, proposed GEEP model is handled via ADMM method to preserve the privacy of private gas and electricity energy parties in an environment with different uncertainties. The superstructure of the proposed GEEP model is presented in Fig. 1. In the following, centralized expansion planning model of gas and electricity networks together with related complements and constraints is defined in subsection 2.1 to 2.6. Then, using a decentralized model based on ADMM, centralized model of GEEP is decomposed into two optimization problems for gas and electricity networks in section 2.7. Finally, subsection 2.8 manages uncertainties in the proposed decentralized GEEP model.

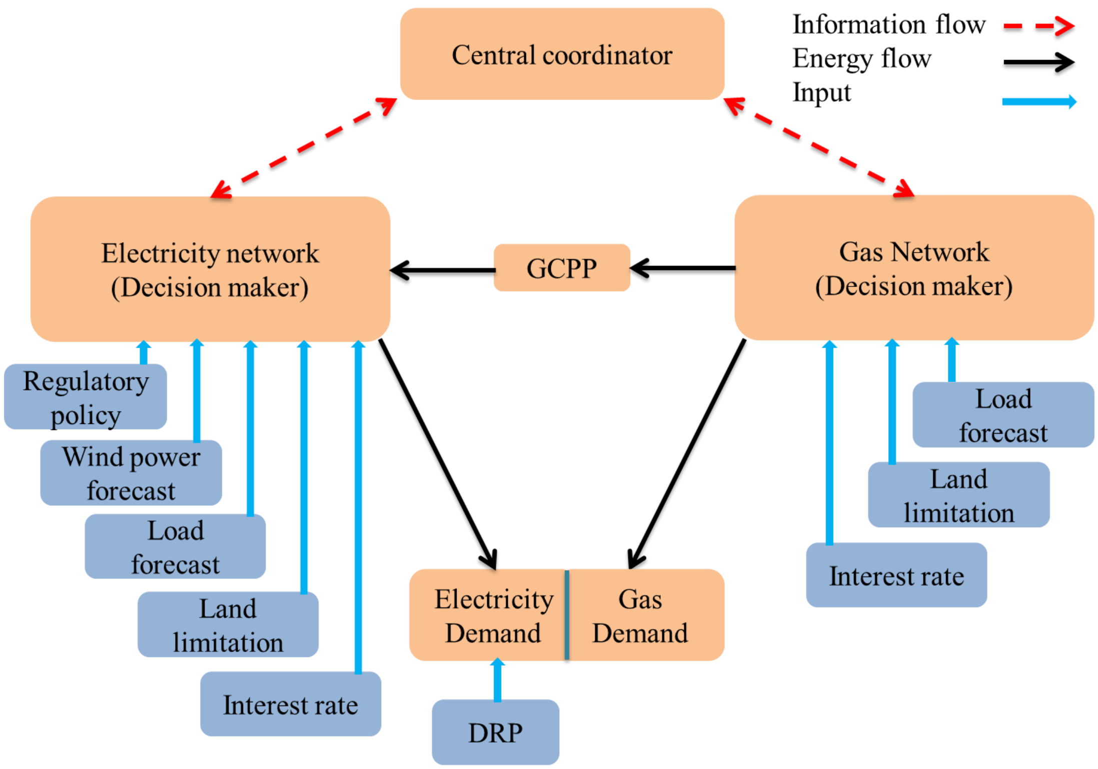

Fig. 1 Superstructure of the proposed GEEP model

It is noteworthy that this paper assumes GCPPs as the only link between gas and electricity networks. However, power to gas technology can also be included in the model easily. Market mechanism is not modeled and constant prices are used during the simulation process. Besides, as the provided GEEP model is an expansion planning model, DC load flow of electricity system as well as steady state gas flow equations are employed in the operation simulation for the sake of simplicity.

2.1 Formulation of centralized model

In gas-electricity system complemented with wind farms and DRPs, the objective function of GEEP model is defined as (1).

$$
Min\ \ C^{GEEP}=\sum_{\omega}\mathbb{P}_{\omega}\left\{\begin{array}{c}
\left(\frac{P}{A},\tilde{\imath}_{\omega},T\right)\left[\begin{array}{c}
\sum_{mn}(u_{mn}^{trans}cost_{mn}^{trans})\left(\frac{A}{P},\tilde{\imath}_{\omega},T^{t}\right)\\
+\sum_{m,h}u_{m,h}^{gen}P_{s_{m,h}}^{R}cost_{m,h}^{gen}\left(\frac{A}{P},\tilde{\imath}_{\omega},T_{m,h}^{g}\right)\\
+\sum_{\hat{m}}u_{\hat{m}}^{W}P_{w_{\hat{m}}}^{R}cost_{\hat{m}}^{W}\left(\frac{A}{P},\tilde{\imath}_{\omega},T_{W}^{g}\right)\\
+\sum_{ij}u_{ij}^{Pipe}\,L_{ij}^{Pipe}\,A_{ij}^{Pipe}cost_{ij}^{Pipe}\left(\frac{A}{P},\tilde{\imath}_{\omega},T^{p}\right)
\end{array}\right]\\
+\sum_{y=1}^{T}\left(\frac{P}{F},\tilde{\imath}_{\omega},y\right)\left[\begin{array}{c}
\sum_{d,t,m,h}\lambda_{m,h,y,d,\omega}^{FC}FC_{m,h,y,d,t,\omega}u_{m,h}^{gen}\\
+\sum_{d,t,m}\left(P_{r_{m,y,d,t,\omega}}\lambda_{r_{m,y,d,t,\omega}}^{elec}+\lambda_{m,y,d,t,\omega}^{DR}P_{DR_{m,y,d,t,\omega}}^{-}\right)\\
+\sum_{d,i}\left(Q_{l_{i,y,d,\omega}}^{Npp}\right)\lambda_{l_{i,y,d,\omega}}^{gas}+\sum_{d,i}Q_{r_{i,y,d,\omega}}\lambda_{r_{i,y,d,\omega}}^{gas}
\end{array}\right]
\end{array}\right\} \tag{1}
$$

where, terms A, P, and F represent annual value, present value, and future value, respectively [31] and are calculated as follows:

$$
\left(\frac{P}{A},\tilde{\imath}_{\omega},T\right)=\frac{\left(1+\tilde{\imath}_{\omega}\right)^{T}-1}{\tilde{\imath}_{\omega}\left(1+\tilde{\imath}_{\omega}\right)^{T}} \tag{2}
$$

$$
\left(\frac{P}{F},\tilde{\imath}_{\omega},T\right)=\left(1+\tilde{\imath}_{\omega}\right)^{-T} \tag{3}
$$

$$
\left(\frac{A}{P},\tilde{\imath}_{\omega},T\right)=\frac{\tilde{\imath}_{\omega}\left(1+\tilde{\imath}_{\omega}\right)^{T}}{\left(1+\tilde{\imath}_{\omega}\right)^{T}-1} \tag{4}
$$

GEEP model minimizes expected value of total operation and investment cost of an integrated gas-electricity system. Proposed model comprises of the net present value (NPV) of investment, operation and DRP costs. Terms one to four of (1) indicate the NPV of investments in transmission lines, generation units, and gas pipelines expansions, respectively. Generation expansion includes both GCPPs and wind farms. Remaining terms are NPV of the entire system operation and DRP costs which includes terms five to seven as the NPV of generation cost and two terms including DRP cost of electric system, respectively. Operating cost of generating units includes both GCPPs and the other non-GCPPs. Besides, terms eight and nine include NPV of the non-power plant gas demand and curtailment costs, respectively. In the following subsections, conditions and constraints applied to GEEP model are explained. In these sections, constraints (5)-(26) must be satisfied for each day d of year y.

2.2 Demand response model

In this paper, DRP cost is integrated within operation and investment costs so as to find a flexible expansion plan of the integrated energy system [6]. In the proposed DRP, both shiftable and shedable load opportunities are considered to study the effects of flexible electricity loads on expansion plan of gas-electricity networks. In the proposed DRP, load shedding ($P_{r_{m,y,d,t,\omega}}$) and shifting ($P^{-}_{DR_{m,y,d,t,\omega}}$) mechanisms are modeled as terms six and seven in (1), respectively. DRP constraints are well described in appendix.

2.3 Uncertainties modeling

In this paper, wind power output, interest rate, and load growth are known as source of uncertainties. The uncertainties are considered as scenarios with associated probabilities. Wind speed is modeled by the Weibull distribution as a proper expression model of wind speed behavior in each forecasted period. Weibull parameters are set according to the long-term meteorological observations of selected area [32]. The output power of wind farm is calculated using the wind farm power curve. A multi-stage probabilistic model of wind farm outputs is used in this paper that assigns a probability to each level of output power [33]. Therefore, the output power scenarios of wind farm are used to investigate the impact of wind power on the proposed GEEP model.

Interest rate is another source of uncertainty that is considered in this study. Different inflation rates in developing countries and central bank decisions on interest rate in both developing countries and leading economies introduces uncertainty in planning phase. Consequently, NPV of planning schemes is uncertain. Uncertainties in load growth of both gas and electricity systems are also considered as several scenarios to provide a coordinated expansion plan that mitigates uncertainties in demand forecast. Moreover, regulatory framework is considered as a constraint. Some countries have rules for new investments in renewables which limits the penetration level of such sources in energy mix of the power system [34].

2.4 Electricity system constraints

DC load flow is used to study feasible operation of the electricity system. In the following, constraint (5) ensures power balance at each bus of the electricity system. Power flow through each transmission line is determined by (6). According to the DC load flow, (7) fixes the angle of the reference bus. Constraint (8) sets the limits of generation units. Power flow in transmission lines is bounded by (9). The lower and upper limits of load curtailment are expressed by (10). Constraint (11) determines the fuel consumption of generation units. A regulatory framework for renewables is incorporated by (12) that sets an upper limit for new wind farm installations due to the regulatory framework policies. Maximum available land for GCPPs and wind turbines are restricted by constraints (13) and (14), respectively.

$$\sum_{h} u_{m,h}^{gen} \times P_{s_{m,h,y,d,t,\omega}} + u_m^W P_{W_{m,y,d,t,\omega}} = \sum_{n} u_{mn}^{trans} \times P_{f_{m,n,y,d,t,\omega}} + P_{l_{m,y,d,t,\omega}}^E - P_{r_{m,y,d,t,\omega}} \qquad \forall t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{5}$$

$$P_{f_{m,n,y,d,t,\omega}} = P_b \times y_{mn}\left(\theta_{m,y,d,t,\omega} - \theta_{n,y,d,t,\omega}\right) \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{6}$$

$$\theta_{ref} = 0 \tag{7}$$

$$\underline{P_{s_{m,h}}} \leq P_{s_{m,h,y,d,t,\omega}} \leq \overline{P_{s_{m,h}}} \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, h \in \mathcal{H}, \omega \in \Omega \tag{8}$$

$$-\overline{P_{f_{mn}}} \leq P_{f_{mn,y,d,t,\omega}} \leq \overline{P_{f_{mn}}} \qquad \forall\ t \in \mathcal{T}, mn \in \mathcal{TL}, \omega \in \Omega \tag{9}$$

$$0 \leq P_{r_{m,y,d,t,\omega}} \leq P_{l_{m,y,d,t,\omega}}^E \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{10}$$

$$FC_{m,h,y,d,t,\omega} = \frac{(\alpha_{m,h} + \beta_{m,h} P_{s_{m,h,y,d,t,\omega}} + \gamma_{m,h} P_{s_{m,h,y,d,t,\omega}}{}^{2})}{GHV_h} \qquad \forall t \in \mathcal{T}, m \in \mathcal{B}, h \in \mathcal{H}, \omega \in \Omega \tag{11}$$

$$\sum_{\widehat{m}} u_{\widehat{m}}^{W} P_{W_{\widehat{m}}}^{R} \leq \overline{P^{W}} \tag{12}$$

$$\sum_{h} u_{m,h}^{gen} \times P_{s_{m,h,y,d,t,\omega}} \leq \overline{A_m^G} \qquad \forall\ m \in \mathcal{B} \tag{13}$$

$$u_m^W P_{W_{m,y,d,t,\omega}} \leq \overline{A_{\widehat{m}}^{W}} \qquad \forall\ \widehat{m} \in \mathcal{B} \tag{14}$$

2.5 Gas system constraints

In this paper, steady-state flow equations are used to describe the gas system behavior. In the following, constraint (15) models the flow limits in pipelines. Constraint (16) expresses the limitations of gas supply at different source nodes. Constraints (17) and (18) express the Weymouth equation [7], which specifies the relation between gas pressure difference and gas flow at passive and active pipes, respectively. An active/passive pipeline is a line that has/doesn't have a compressor. Constraint (19) ensures that gas flow is unidirectional in active pipes. Constraint (20) indicates gas pressure bounds at each node. The lower and upper limits of non-power plant gas load curtailment are expressed by (21). Gas nodal balance is modeled using (22). Compressor restricts the pressure ratio in active pipelines as (23). Gas consumed by the compressors can be approximated using (24) with node *i/j* as primary/secondary side [35]. Maximum available land for pipelines is restricted by constraint (25).

$$\underline{Q_{f_{ij}}} \leq Q_{f_{ij,y,d,\omega}} \leq \overline{Q_{f_{ij}}} \qquad \forall\ ij \in \mathcal{PL}^{p}, \omega \in \Omega \tag{15}$$

$$\underline{Q_{S_i}} \leq Q_{S_{i,y,d,\omega}} \leq \overline{Q_{S_i}} \qquad \forall\ i \in \mathcal{N}, \omega \in \Omega \tag{16}$$

$$Q_{f_{ij,y,d,\omega}}{}^{2} = sign(Q_{f_{ij,y,d,\omega}}) K_{ij}^{pipe^2} (\pi_{i,y,d,\omega}^{g} - \pi_{j,y,d,\omega}^{g}) \qquad \forall\ ij \in \mathcal{PL}^{p}, \omega \in \Omega \tag{17}$$

$$Q_{f_{ij,y,d,\omega}}{}^{2} \geq sign(Q_{f_{ij,y,d,\omega}}) K_{ij}^{pipe^2} (\pi_{i,y,d,\omega}^{g} - \pi_{j,y,d,\omega}^{g}) \qquad \forall\ ij \in \mathcal{PL}^{A}, \omega \in \Omega \tag{18}$$

$$0 \leq Q_{f_{ij,y,d,\omega}} \leq \overline{Q_{f_{ij}}} \qquad \forall\ ij \in \mathcal{PL}^{A}, \omega \in \Omega \tag{19}$$

$$\underline{pr_i^g} \leq pr_{i,y,d,\omega}^{g} \leq \overline{pr_i^g} \qquad \forall\ i \in \mathcal{N}, \omega \in \Omega \tag{20}$$

$$0 \le Q_{r_{i,y,d,\omega}} \le Q_{l_{i,y,d}}^{Npp} \qquad \forall\, i \in \mathcal{N}, \omega \in \Omega \tag{21}$$

$$\sum_{j} u_{ij}^{Pipe} Q_{f_{ij,y,d,\omega}} = Q_{s_{i,y,d,\omega}} - (Q_{l_{i,y,d,\omega}}^{pp} + Q_{l_{i,y,d,\omega}}^{Npp} - Q_{r_{i,y,d,\omega}} + Q_{l_{i,y,d,\omega}}^{comp}) \qquad \forall\, i \in \mathcal{N}, \omega \in \Omega \tag{22}$$

$$pr_{i,y,d,\omega}^{g} \le pr_{j,y,d,\omega}^{g} \le R_{ij}^{comp} pr_{i,y,d,\omega}^{g} \qquad \forall\, ij \in \mathcal{PL}^{A}, \omega \in \Omega \tag{23}$$

$$Q_{l_{i,y,d,\omega}}^{comp} = \int_{ij}^{comp} Q_{f_{ij,y,d,\omega}} (pr_{j,y,d,\omega}^{g} - pr_{i,y,d,\omega}^{g}) \qquad \forall\, ij \in \mathcal{PL}^{A}, \omega \in \Omega \tag{24}$$

$$u_{ij}^{Pipe} Q_{f_{ij,y,d,\omega}} \le \overline{A_{ij}^{P}} \qquad \forall\, ij \in \mathcal{PL}^{A} \cup \mathcal{PL}^{p} \tag{25}$$

2.6 Coupling constraint

The key point for decentralized optimization is to find the proper coupling constraints across the connected entities. In our proposed model, constraint (26) determines the upper limit of gas quantity that gas system can deliver to GCPPs at each bus and it is selected as coupling constraint.

$$\sum_{\hat{h},t} FC_{m,\hat{h},y,d,t,\omega} \le Q_{l_{i,y,d,\omega}}^{pp} \qquad \forall m \in \mathcal{B}, i \in \mathcal{N}, \omega \in \Omega \tag{26}$$

2.7 Decentralized model based on Alternating direction method of multipliers

In a central method, (1) is supposed as the objective function of a central coordinator that is subjected to technical constraints of gas and electricity networks i.e. constraints (5)-(26). However, in the GEEP model (1), all the variables and constraints are local except constraint (26) which can be handled via the ADMM method [36]. Coupling constraint (26) can be relaxed and augmented into the objective functions as penalty for electricity and gas agents. So, each agent is tackled independently and expansion is coordinated with minimum data exchange. Each operator solves its optimization problem and shared information is exchanged between the two agents in a repetitive process, till they reach an agreement. A central coordinator minimizes disagreements between the two agents by obtaining information on the required gas of GCPPs at each bus of electricity system and maximum quantity that gas system can deliver to GCPPs at each node of gas system and resending the corrected information to them. Based on ADMM method, decomposed optimization for electricity system is as follows:

$$
Min\sum_{\omega}\mathbb{P}_{\omega}\left\{\begin{array}{c}
\left(\frac{P}{A},\tilde{\imath}_{\omega},T\right)\left[\begin{array}{c}
\sum_{mn}\left(u_{mn}^{trans^{k+1}}cost_{mn}^{trans}\right)\left(\frac{A}{P},\tilde{\imath}_{\omega},T^{t}\right)\\
+\sum_{m,h}u_{m,h}^{gen}P_{s_{m,h}}^{R}cost_{m,h}^{gen}\left(\frac{A}{P},\tilde{\imath}_{\omega},T_{m,h}^{g}\right)\\
+\sum_{\hat{m}}u_{\hat{m}}^{W}P_{w_{\hat{m}}}^{R}cost_{\hat{m}}^{W}\left(\frac{A}{P},\tilde{\imath}_{\omega},T_{W}^{g}\right)
\end{array}\right]\\
+\sum_{y=1}^{T}\left(\frac{P}{F},\tilde{\imath}_{\omega},y\right)\left[\begin{array}{c}
\sum_{d,t,m,h}\lambda_{m,h,y,d,\omega}^{FC}{FC_{m,h,y,d,t,\omega}}^{k+1}u_{m,h}^{gen^{k+1}}\\
+\sum_{d,t,m}\left(\lambda_{r_{m,y,d,t,\omega}}^{elec}\,{P_{r_{m,y,d,t,\omega}}}^{k+1}+\lambda_{m,y,d,t,\omega}^{DR}{P_{DR_{m,y,d,t,\omega}}^{-}}^{k+1}\right)\\
+\sum_{d,i,m}\begin{array}{c}
\mu_{im,y,d,\omega}^{k}\left({Q_{l_{i,y,d,\omega}}^{pp}}^{k}-\sum_{\hat{h},t}{FC_{m,\hat{h},y,d,t,\omega}}^{k+1}\right)\\
+\frac{\rho}{2}\sum_{d,i,m}\left\|{Q_{l_{i,y,d,\omega}}^{pp}}^{k}-\sum_{\hat{h},t}{FC_{m,\hat{h},y,d,t,\omega}}^{k+1}\right\|_{2}^{2}
\end{array}
\end{array}\right]
\end{array}\right\} \tag{27}
$$

$s.t.$

(5)- (14) (28)

Likewise, decomposed optimization for gas system is as below:

$$
Min\sum_{\omega}\mathbb{P}_{\omega}\left\{\begin{array}{c}
\left(\frac{P}{A},\tilde{\imath}_{\omega},T\right)\left[\sum_{ij}u_{ij}^{Pipe^{k+1}}\,L_{ij}^{Pipe}\,A_{ij}^{Pipe}cost_{ij}^{Pipe}\left(\frac{A}{P},\tilde{\imath}_{\omega},T^{p}\right)\right]\\
+\sum_{y=1}^{T}\left(\frac{P}{F},\tilde{\imath}_{\omega},y\right)\left[\begin{array}{c}
\sum_{d,i}\left(\lambda_{l_{i,y,d,\omega}}^{gas}{Q_{l_{i,y,d,\omega}}}^{k+1}+\lambda_{r_{i,y,d,\omega}}^{gas}{Q_{r_{i,y,d,\omega}}}^{k+1}\right)\\
+\sum_{d,i,m}\begin{array}{c}
\mu_{im,y,d,\omega}^{k}\left({Q_{l_{i,y,d,\omega}}^{pp}}^{k+1}-\sum_{\hat{h},t}{FC_{m,\hat{h},y,d,t,\omega}}^{k}\right)\\
+\frac{\rho}{2}\sum_{d,i,m}\left\|{Q_{l_{iyd\omega}}^{pp}}^{k+1}-\sum_{\hat{h},t}{FC_{m,\hat{h},y,d,t,\omega}}^{k}\right\|_{2}^{2}
\end{array}
\end{array}\right]
\end{array}\right\} \tag{29}
$$

$s.t.$

(15)- (25) (30)

The coordination among agents is achieved by updating Lagrangian multipliers. Dual variable μ_{im} is updated by coordinator using sub-gradient method [36] as (31). Constant ρ is a penalty factor to help convergence and it is obtained through experience. The updating process of Lagrangian multipliers is given below.

$$\mu_{im,y,d,\omega}^{k+1} = \mu_{im,y,d,\omega}^{k} + \rho({Q_{l_{i,y,d,\omega}}^{pp}}^{k} - \sum_{\hat{h},t} {FC_{m,\hat{h},y,d,t,\omega}}^{k}) \qquad \omega\in\Omega \qquad (31)$$

In the electricity system sub-problem, $FC_{m,\hat{h},y,d,t,\omega}$ is variable while $Q_{l_{i,y,d,\omega}}^{pp}$ and $\mu_{im,y,d,\omega}$ are supposed to be constants that are determined by the consensus of gas system operator and coordinator, respectively. On the other hand, in the gas system sub-problem, $Q_{l_{i,y,d,\omega}}^{pp}$ is a variable and $FC_{m,\hat{h},y,d,t,\omega}$ and $\mu_{im,y,d,\omega}$ are supposed as constants. $FC_{m,\hat{h},y,d,t,\omega}$ is determined through the consensus of electricity system operator and the coordinator. Repetitive process minimizes the difference between $FC_{m,\hat{h},y,d,t,\omega}$ and $Q_{l_{i,y,d,\omega}}^{pp}$.

Two criteria must be met by the coordinator to stop the repetitive process: 1) disagreement between gas and electricity entities on gas consumption of GCPPs is less than a predefined value and 2) gas consumption of GCPPs on two consecutive iterations is within a predefined criterion. Proposed stopping are defined as follows.

$$\left\|\sum_{\hat{h},t} {FC_{m,\hat{h},y,d,t,\omega}}^{k+1} - {Q_{l_{i,y,d,\omega}}^{pp}}^{k+1}\right\|_2^2 \le \varepsilon_1 \qquad \forall m\in \mathcal{B}, i \in \mathcal{N}, \omega\in\Omega \qquad (32)$$

$$\left\|\sum_{\hat{h},t} {FC_{m,\hat{h},y,d,t,\omega}}^{k+1} - \sum_{\hat{h},t} {FC_{m,\hat{h},y,d,t,\omega}}^{k}\right\|_2^2 \le \varepsilon_2 \qquad \forall m\in \mathcal{B}, \omega\in\Omega \qquad (33)$$

Constraints (31)-(33) are valid for each day d of year y.

ADMM algorithm:

1- Initialize $Q_{l_{i,y,d,\omega}}^{pp}, FC_{m,\hat{h},y,d,t,\omega}, \mu_{im,y,d,\omega}$

2- Electricity system operator solves sub-problem (27)-(28) and sends $\sum_{\hat{h},t} {FC_{m,\hat{h},y,d,t,\omega}}^{k+1}$ to gas system operator,

3- Gas system operator solves sub-problem (29)-(30) and sends ${Q^{pp}_{l_{i,y,d,\omega}}}^{k+1}$ to electricity system operator,

4- Coordinator updates $\mu^{k+1}_{im,y,d,\omega}$ using (31) for each scenario ω and send it for gas and electricity system operators,

5- Coordinator checks the stop criteria (32)-(33), if they are not satisfied go to 2, otherwise stop.

2.8 Dealing with uncertainties

A set of possible scenarios for modeling uncertainties in the long-term GEEP is considered. A weight is assigned to each scenario based on the historic data of the considered uncertainties that reflects the possibility of their occurrence. This way, computational burden for solving scenario-based stochastic models depends on the number of scenarios. Hence, an effective scenario reduction method could be very essential in solving large scale systems. In this paper, backward scenario reduction technique is used as a scenario-based approximation with a smaller number of scenarios and a reasonably good approximation of original system [37].

3. Case Study

This section examines the proposed method on a real case study in Khorasan province of Iran.

3.1 Data

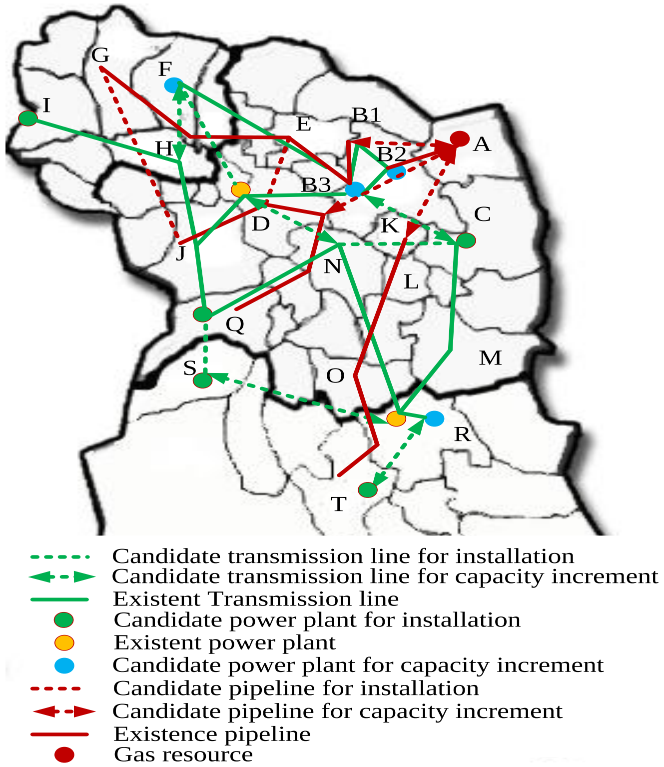

Fig. 2 Khorasan gas-electricity system

To examine the proposed stochastic decentralized GEEP model, a real case study which represents the gas-electricity system in Khorasan province of Iran is considered. High penetration level of GCPPs, an existing wind farm, and a high potential location for new wind farms installations are the advantages of the proposed case study. The electricity system consists of 19 transmission lines and 17 buses in which 33 GCPPs are connected to 7 buses. In the gas network, there are 16 nodes that are connected together through 15 pipelines. Supplementary data of the proposed electricity and gas networks are given in [38] and [12], respectively. A planning period of 15 years as well as a 3% annually load growth is considered in this paper. Currently, demand in the electricity system is 3129 MW and a maximum generation of 3880 MW is available. In the gas system, consumption rate is 39.133 Million Standard Cubic Meters per Day (MSCMD) by other sectors than GCPPs such as residential consumers. A simplified layout of the case study is depicted in Fig. 2 where existing gas nodes and electricity buses are specified with letters

A to T. In the proposed case study, region M is considered as a potential location for new wind farm installation. Existing facilities and their candidates for expansion are also depicted in Fig. 2. Investment cost of power plants, transmission lines and pipelines are given in [7]. The capacity of new GCPPs is considered to be added to the electricity network in 200 MW steps.

To study the effect of uncertainties, scenarios are made according to the historical data of interest rate and wind speed [32]. K-means clustering algorithm is used for clustering historical data and obtaining probabilities of each cluster [39]. Four clusters including 0-4 m/s, 5-8 m/s, 9-12 m/s, and 13-16 m/s are considered for wind speed. Also, four annual load growth possibilities including 3%, 4%, 5%, and 6% are considered for both gas and electricity networks. Consequently, considering so-called four levels for load growth, three clusters for interest rate (including 13%, 23%, and 43%), and also four clusters for wind farm output power, a total number of 48 scenarios are generated. With a backward scenario reduction algorithm the number of scenarios is reduced to four scenarios as given in Table 1.

Table 1 Data of scenarios

Scenario	Prob.	Wind	Interest rate	Load growth (%)
1	0.07	50%	23%	3
2	0.38	Rated	43%	4
3	0.30	50%	13%	5
4	0.25	50%	13%	6

3.2 Results

Six cases are examined with different DRP and regulatory frameworks on the proposed stochastic decentralized GEEP model. To study the effect of uncertainties, two deterministic cases with load growth of 3% annually and interest rate of 13% are also investigated. The stochastic and deterministic cases are as follows:

- Case 1: Stochastic GEEP considering DRP without new wind installation
- Case 2: Stochastic GEEP considering DRP and regulatory limitation of 500 MW for new wind installation
- Case 3: Stochastic GEEP considering DRP and regulatory limitation of 1000 MW for new wind installation
- Case 4: Stochastic GEEP considering regulatory limitation of 500 MW for new wind installation without DRP
- Case 5: Deterministic GEEP without DRP support
- Case 6: Deterministic GEEP considering DRP

Expansion planning of the understudy system is performed using central and ADMM decentralized methods for all abovementioned cases. It should also be mentioned that all of the algorithms and simulations are carried out on a desktop computer with 4 GB of RAM and 2.5 GHz processor with GAMS software and Baron solver.

Comparing the results of central and ADMM models shows that both the ADMM and central methods produce the same results while in the proposed ADMM method, gas and electricity networks are tackled independently with a minimum data exchange. To validate the accuracy of the proposed method, convergence of ADMM in different scenarios is assessed. In all scenarios of all cases ADMM converges in less than 9 iterations. Convergence process for different scenarios of Case 3 is shown in Fig. 3, where, the convergence process for electricity and gas systems is represented according to the total cost (TC) of case 3 as a holistic case. TC^* points the total cost using centralized method that is used as a benchmark in the convergence analysis. As it can be seen in Fig. 3, convergence process in scenarios 1 to 3 starts from a low value while in scenario 4 it has a considerable higher value because of dealing with extreme condition such as higher load growth condition. ADMM method converges in 4 iterations in all scenarios of Case 3.

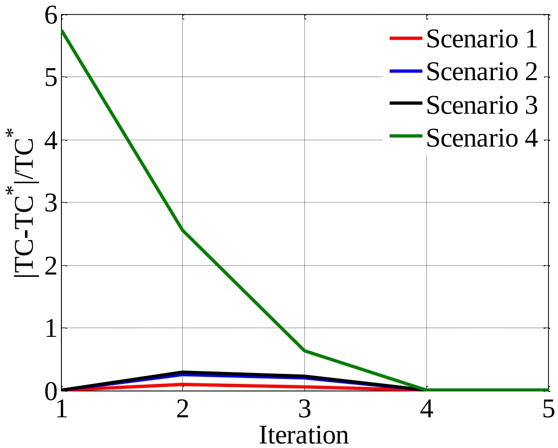

Fig. 3 Convergence of ADMM method in Case 3

Complementary results for different cases including selected transmission line, generator, and pipeline candidates, NPV of investment cost for each entity, NPV of generation cost, NPV of DRP cost, NPV of total cost and processing time according to the ADMM method are given in Table 2. As Table 2 shows, expansion planning results of all stochastic cases are the same for pipelines and transmission lines. Table 2 also indicates that load growth, DRP, and new wind installation up to 1000 MW has no effect on the expansion planning decisions of gas system and electricity network transmission lines. Size of selected generation and pipeline candidates in different cases are given in Table 3. As shown in Table 3, expansion planning decisions on generation candidates change logically. Meaning, a few changes are made in generation candidates within diverse cases. Table 3 shows that location of new generation candidates are the same in cases 1 to 4 while the associated sizes are different in these cases. Based on Table 3, in deterministic cases 5 and 6 in comparison with stochastic cases 1 to 4 some new generation capacity addition is not needed.

Table 2. Detailed results of GEEP model in different cases using the proposed ADMM method

Case	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6

	Elec.	Gas	Elec.	Gas	Elec.	Gas	Elec.	Gas	Elec.	Gas	Elec.	Gas
Selected Trans. line / Pipeline Candidates	F-H, B3-C, D-N	A-B1, A-D	F-H, B3-C, D-N	A-B1, A-D	F-H, B3-C, D-N	A-B1, A-D	F-H, B3-C, D-N	A-B1, A-D	F-H, B3-C, D-N	A-B1, A-D	F-H, B3-C, D-N	A-B1
Selected Gen. Candidates	I,Q,T,B2	-	I,Q,T, B2	-	I,Q,T, B2	-	I,Q,T, B2	-	Q, B2	-	B2	-
Investment Cost ($10^6\$$)	1331.3	579.6	1512.5	579.6	1693.6	579.6	1751	579.6	846.3	579.6	523.4	25
Expected Gen. cost ($10^9\$$)	2.90	21.98	2.68	21.73	2.45	21.52	2.73	21.77	3.11	22.65	3.07	22.62
Expected DRP cost ($10^6\$$)	0.69	-	0.58	-	0.75	-	-	-	-	-	0.64	-
Total expected Cost of ADMM method ($10^9\$$)	26.79		26.55		24.75		26.82		27.18		26.24	
Processing time (s)	13160		13530		13525		12445		3405		4130	

Table 3 Size of pipeline and electricity generation expansion candidates

Case #	**Selected Generation candidates**		**Selected Pipeline candidates**	
	Location	**Size (MW)**	**Location**	**Diameter (mm)**
1	I/Q/T/ B2	800/1000/400/800	A-B1/ A-D	914
2	I/Q/T/ B2	800/600/ 400/800	A-B1/ A-D	914
3	I/Q/T/ B2	400/600/ 400/800	A-B1/ A-D	914
4	I/Q/T/ B2	800/1000/400/1000	A-B1/ A-D	914
5	Q/ B2	1000/600	A-B1/ A-D	914
6	B2	800	A-B1	914

Electricity generation cost in different cases is shown in Fig. 4. In this figure, effect of new wind installation and regulatory framework is studied in cases 1 to 3. As it is shown in Fig. 4, as capacity of new wind farm increases, electricity generation cost decreases. Also, it is shown in Fig. 4 that NPV of generation costs for deterministic cases, i.e. cases 5 and 6 are more than stochastic cases 1-4. Investment cost of electricity network is depicted in Fig. 5. Based on Table 2, as capacity of new wind power plant increases in cases 1 to 3, the expansion capacity of GCPPs decreases and as a result, electricity network investment cost increases, mainly due to the fact that investment cost of 1 MW of a wind power plant is higher than 1 MW of a GCPP. However, as the goal in stochastic cases is to look for a plan that suits to all scenarios, investment costs of stochastic cases 1-4 are higher than deterministic cases 5 and 6. Total expected cost of gas and electricity networks is depicted in Fig. 6. Decreasing effect of new wind installation on gas and electricity total costs can be seen in cases 1-3. Comparing the total expected cost in cases 2 and 4 in Fig. 6 shows that DRP decreases the total expected cost of both gas and electricity networks. Also, by comparing cases 1-6 in Tables 2-3 and Figs. 4-6, it is concluded that:

1- Unlike case 1, there is no DRP in case 4 which results in adding a 500 MW new wind farm and 200 MW new GCPP in expansion planning phase. In other words, new capacity addition could be avoided/reduced by enabling DRPs.

2- In case 3 (compared to case 2), by increasing the capacity of new wind farm from 500 MW to 1000 MW, capacity of new GCPPs decreases by 400 MW. Although total investment cost increases in case 3 in comparison with case 2, due to higher investment cost for capacity addition of wind farm than GCPP, total expected cost of expansion planning decreases more in case 3 (due to the lower fuel/operating cost of both gas and electricity networks).

3- In case 2, due to the installation of 500 MW new wind farm, capacity of new GCPPs decreases by 400 MW as compared to case 1. Although total investment cost increases in case 2, total expected cost of expansion planning decreases in this case compared to case 1.

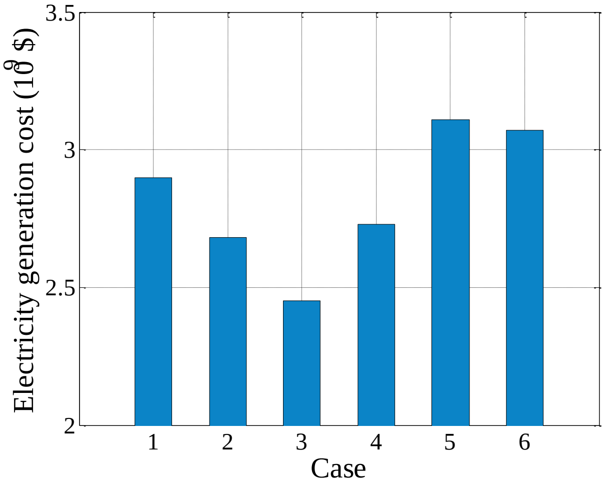

Fig. 4 Electricity generation cost in different Cases

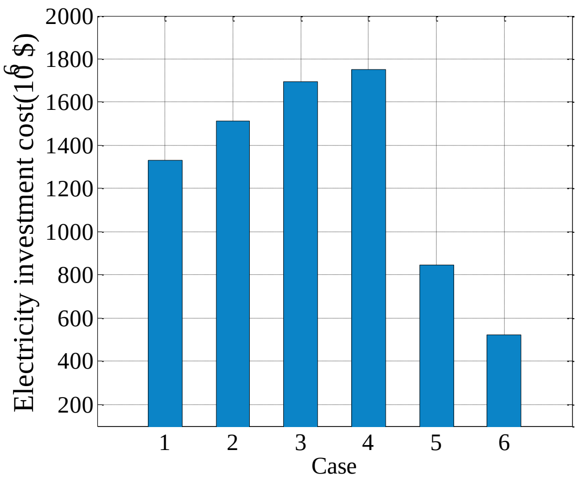

Fig. 5 Electricity investment cost in different Cases

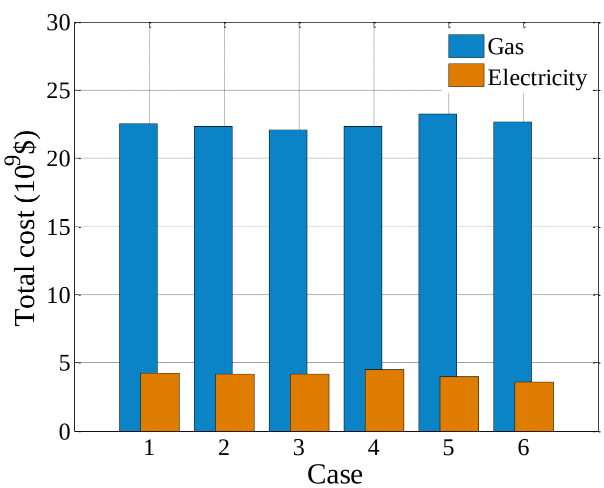

Fig. 6 Total cost of ADMM method in different Cases

4- In case 6, DRP eliminates the need for generation expansion in bus Q and decreases capacity of new GCPPs by 800 MW. Consequently, DRP eliminates the need for expansion of pipeline A-D. Hence, total expected cost of case 6 decreases in comparison to case 5.

Expansion planning decisions of generation opportunity show that DRP can reduce the needs for new generation installations through peak shaving and load shifting actions. In this regard, case 6 as a deterministic case that considers the effect of DRP on the proposed GEEP model, is considered as a benchmark. The effect of different DRP penetration levels on electricity network investment cost is shown in Fig. 7. To better investigate the DRP effect, results of electricity network expansion cost, investment cost, generation candidates, DRP cost and total expected cost of gas and electricity networks are summarized in Table 4. From the results, it is obvious that incorporating DRP results in lower investment cost of electricity network. However, as it can be seen in Fig. 7, with DRP penetration levels above 10%, electricity investment cost does not change anymore. Fig. 7 also indicates that if DRP penetration level increases beyond 20%, DRP cost remains unchanged. The reason is that DRP reaches the maximum load shedding action that is defined in the load variation range. Also, a DRP penetration level higher than 10% eliminates the need to generation expansion in bus Q as it is shown in Table 4 and Fig. 7.

Table 4 Effect of DRP penetration level on electricity network expansion planning

DRP	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**
Expansion cost (10^9\$)	3.96	3.6	3.59	3.59	3.59	3.59
Investment Cost (10^6\$)	846.3	523.4	523.4	523.4	523.4	523.4
Generation candidates	Q,B2	B2	B2	B2	B2	B2
DRP cost (10^6\$)	0.32	0.64	0.88	1.01	1.02	1.02
Total expected Cost (10^9\$)	27.19	26.24	26.23	26.23	26.23	26.23

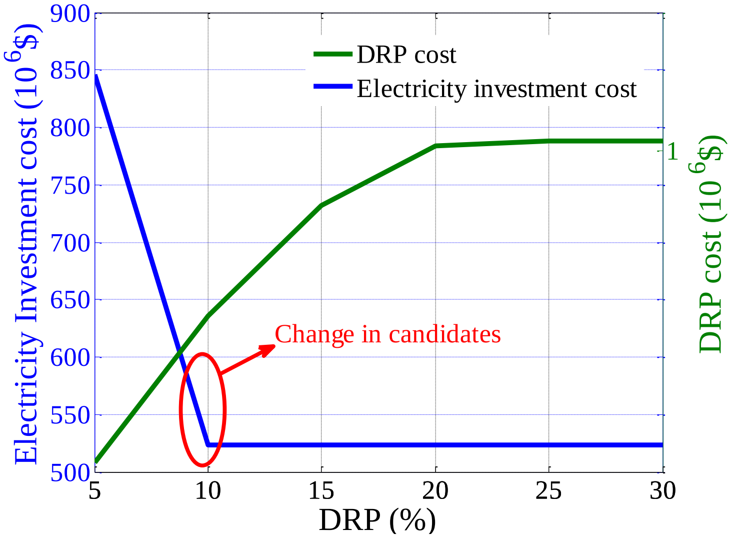

Fig. 7 Effect of DRP penetration level on electricity network investment and DRP costs

Impact of DRP on daily load profile of electricity system in region D is shown in Fig. 8. It is obvious that as DRP penetration level increases, smoother daily load profile is achieved.

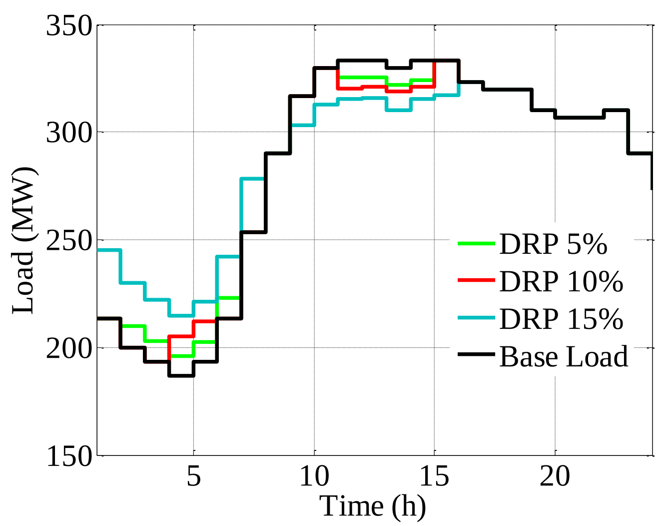

Fig. 8 Effect of DRP penetration level on daily load profile of D in electricity system

Land scarcity is another factor which can be imperative in expansion planning studies. In this step, limitations are imposed in maximum available land for GCPPs, wind turbines and pipelines. Considering case 3 as a holistic case, results for land limitation are studied in two more cases including:

- Case 7: land limitation for GCPPs and wind turbines
- Case 8: land limitation for pipelines

Obtained results are summarized in Table 5 according to selected transmission line, generation, and pipeline candidates, NPV of investment cost for each entity, NPV of generation cost, NPV of total cost and based on the ADMM method. Results show that with restriction in land area for wind turbines and GCPPs in B, extra capacity is satisfied by new installation in T and capacity increment in F. Wind turbine installation is confined to about 500 MW and similar limitation is applied to GCPPs in B. Besides, restriction in pipeline land leads to size decrement of A-D pipeline and installing new E-D pipeline which is costly. Totally, it can be concluded that land area limitation changes network topology toward a more expensive one.

Table 5 Detailed results of GEEP according to land scarcity

Case	Case 7		Case 8	
	Elec.	Gas	Elec.	Gas
Selected Trans. line / Pipeline Candidates	F-H/B3-C/D-N	A-B1/ A-D	F-H/B3-C/D-N	A-B1/E-D/A-D
Pipeline size (mm)	-	914/914	-	914/304/762
Selected Gen. Candidates	I/Q/T/B2/F	-	I/Q/T/ B2	-
Gen. size (MW)	400/600/ 800/400/400		400/600/ 400/800	
Investment Cost (10^6\$)	1801.4	579.6	1512.5	871.4
Expected Gen. cost (10^9\$)	2.65	22.01	2.45	21.73
Total expected Cost of ADMM method (10^9\$)	27.04		26.56	

4. Conclusion

In this paper a stochastic decentralized model for GEEP was introduced. Different uncertainties including wind power output, interest rate and load growth were considered to have a holistic approach. Regulatory framework of a realistic case study as well as the DRP was also implemented to see how regulatory policies and demand side resource management could affect the GEEP. Compared to the current integrated expansion planning methods, the proposed ADMM method coordinated gas and electricity networks with a minimum data exchange.

Proposed GEEP model was applied to a real case study in Iran and results were compared in different cases. It was shown that DRP can affect expansion decisions and at some penetration levels, can reduce expansion candidates. Moreover, effect of regulatory policies for new renewables on GEEP was studied with different capacities for wind farm. It was shown that renewables could reduce expansion cost of both gas and electricity networks. Also results of stochastic model were compared with those of a deterministic model and it was shown that dealing with extreme conditions and uncertainties could lead to higher expected expansion cost. Effect of restriction in available land was also investigated and topology changes were studied subsequently.

Given the pivotal role of gas and electricity in any country's socio-economic indicators and considering the complex structure of integrated energy systems, prominent priorities of policy makers appear to be determining the optimal generation technologies portfolio as well as the role of prosumers on the optimal composition. It is therefore recommended for future works to study the application of portfolio theory to formulate the optimal expansion plan as well as to investigate the effect of power to gas technology on the stochastic GEEP model, as it can harvest extra power produced by renewables and hence, modifies renewable regulatory policies.

Appendix A- Demand Response Program Model

Shiftable demand response action is modeled as (A.1)-(A.5). In this regard, effective load in each scenario according to the DRP is defined by (A.1). Shiftable load is ensured by (A.2). DRP limitations is indicated by (A.3) and (A.4) for load decrement and increment opportunities, respectively. Constraint (A.5) ensures that only one of the either load increment or decrement opportunities of DRP can be considered in a time period. This is accomplished by binary variables used in (A.3)-(A.5).

$$P^{E}_{l_{m,y,d,t,\omega}} = P_{l_{m,y,d,t,\omega}} - P^{-}_{DR_{m,y,d,t,\omega}} + P^{+}_{DR_{m,y,d,t,\omega}} \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{A.1}$$

$$\sum_{t} (P^{+}_{DR_{m,y,d,t,\omega}} - P^{-}_{DR_{m,y,d,t,\omega}}) = 0 \qquad \forall m \in \mathcal{B}, \omega \in \Omega \tag{A.2}$$

$$0 \le P^{-}_{DR_{m,y,d,t,\omega}} \le u^{-}_{DR_{m,y,d,t,\omega}} \overline{P^{-}_{DR_{m,y,d,t,\omega}}} \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{A.3}$$

$$0 \le P^{+}_{DR_{m,y,d,t,\omega}} \le u^{+}_{DR_{m,y,d,t,\omega}} \overline{P^{+}_{DR_{m,y,d,t,\omega}}} \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{A.4}$$

$$u^{+}_{DR_{m,y,d,t,\omega}} + u^{-}_{DR_{m,y,d,t,\omega}} \le 1 \qquad \forall\ t \in \mathcal{T}, m \in \mathcal{B}, \omega \in \Omega \tag{A.5}$$

Appendix B- Simulation Parameters

Parameters

K^{pipe}_{ij}	[12]
R^{comp}_{ij}	1.6
$Q^{Npp}_{l_{i,y,d,\omega}}$	[12]
$\int^{comp}_{ij}$	0.0025 bar^{-1}
$\lambda^{gas}_{l_{i,y,d,\omega}}$	3.5 $/MSCM
$\lambda^{gas}_{r_{i,y,d,\omega}}$	3.5 e6 $/MSCM

L_{ij}^{Pipe}	[12]
A_{ij}^{Pipe}	[12]
$P_{s_{m,h}}^{R}$	[38]
$P_{w_m}^{R}$	Regulatory policy
$\overline{P^{W}}$	Regulatory policy
$P_{l_{m,y,d,t,\omega}}$	[38]
$\lambda_{r_{m,y,d,t,\omega}}^{elec}$	1e6 $/MW
$\lambda_{m,h,y,d,\omega}^{FC}$	3.5 $/ MSCMD
$\lambda_{m,y,d,t,\omega}^{DR}$	[40]
y_{mn}	[38]
P_b	100 MW
GHV_h	0.0353 MMBTU/MSCM
$cost_{ij}^{Pipe}/cost_{mn}^{trans}/cost_{mh}^{gen}$	[7]
$cost_{m}^{W}$	1466 k$/MW
T	15 year
$T^{t}/T^{g}/T^{p}$	30/20/30 year

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