A Bi-Level Day-Ahead Market-Clearing Mechanism for Coordinated Regional-Local Multi-Carrier Systems in Presence of Energy Storage Technologies

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Abstract

A multi-energy system (MES) provides greater flexibility for the operation of different energy carriers. It increases the reliability and efficiency of the networks in the presence of renewable energy sources (RESs). Various energy carriers such as power, gas, and heat can be interconnected by energy storage systems (ESSs) and combined heat and power units at different levels (e.g., within a region or a local). Non-coordinated optimization of energy systems at local and regional levels does not verify the whole optimal operation of systems since the systems operate without considering their interactions with each other. One of the most famous sources of flexibility is ESSs. Hence, this paper presents a stochastic decentralized approach to evaluate the impact of ESSs on regional-local MES market-clearing within a bi-level framework. On the regional level, the economic interaction between the electricity and NG systems is carried out by a centralized system operator (CSO). In addition, coordination between various energy carriers is implemented by the energy hub operator at the local level. To ameliorate the flexibility of the natural gas (NG) system in the regional MES, the linepack model of gas pipelines has been considered.

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Local MES modeling is performed through multiple input/output ports using a linear energy hub model. The proposed model is a mixed-integer linear programming (MILP), which is solved by CPLEX solver in GAMS software.

Keywords: Decentralized market clearing, two-step iteration-based framework, multi-carrier energy storage, coordinated power and gas networks, energy hub

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Nomenclature

Index and setsIndex and sets

i, b, j	Indices of units, electric buses
t, h, s	Indices of time periods, energy hub, and scenarios
n, m, sp	Indices of NG nodes, and gas resources
l	Indices of NG network loads
A_b^i	Set of power generation units i located at electricity grid bus b
A_n^{sp}	Set of NG producers sp located at NG network node n
A_b^h	Set of energy hub h located at power grid bus b
A_n^h	Set of energy hub h located at NG network node n
A_b^w	Set of energy wind w located at power grid bus b
Tr,z	Sets of power transmission lines and NG network branches
CU, GU	Set of the NGFPP and GFPPs

Parameters

f_b^{Max}	Transmission line capacity
P_i^{Max}, P_i^{Min}	Maximum/ minimum power output of unit i
C_i^{SU}, C_i^{SD}	Costs of start-up and shut-down of NGFPP i
C_i^{GSU}, C_i^{GSD}	Costs of start-up and shut-down of GFPP i.
T_i^{up}, T_i^{dn}	Minimum on and off time of unit i
R_i^{up}, R_i^{dn}	Ramp-up and ramp-down limit of unit i
$v_{sp}^{Max}, v_{sp}^{Min}$	Maximum/minimum of NG producer sp
Pr_n^{Max}, Pr_n^{Min}	Maximum/minimum pressure at node n
pi_s	Probability of scenario s

$D^e_{b,t}$	Electricity demand of bus b at time t
η_{Hc}, η_{Hd}	Heat storage charge and discharge coefficient in energy hub
η_{sc}, η_{sd}	Electricity storage charge and discharge coefficient in energy hub
η_{eb}	Efficiency of the electric boiler
η_{ce}, η_{cg}	Conversion coefficient of NG to electrical and heating energy in CHP unit, respectively
CHP^{Max}_h	Maximum NG input of CHP in energy hub h
EB^{Max}_h	Maximum input power of electric boiler in energy hub h
HC^{Max}_h/HD^{Max}_h	Maximum charging and discharging capacity at the heating storage system in energy hub h
SC^{Max}_h/SD^{Max}_h	Maximum charging and discharging capacity at the electricity storage system in energy hub h
ES^{Max}_h	Maximum electricity energy stored at power storage in energy hub h
HS^{Max}_h	Maximum heating stored in heat storage in energy hub h
y^k_h	Electricity generation of corner point k of CHP in energy hub h
Variables	
$I^s_{i,t}$	Commitment status of unit i at period t in scenario s
$SU^s_{i,t}/SD^s_{i,t}$	Start-up and shut-down cost of NGFPPs unit i at period t in scenario s
$GSU^s_{i,t}/GSD^s_{i,t}$	Start-up and shut-down of GFPPs unit i at period t in scenario s
$y^s_{i,t}/z^s_{i,t}$	Binary variables to determine the Start-up and shut-down status of unit i at period t, equal to 1 if unit i is turned ON/OFF at hour t in scenario s and 0 otherwise
$P_{i,s,t}$	The power output of generator i at period t in scenario s
$PW_{w,s,t}$	The power output of wind unit w at period t in scenario s
$f_{b,j,s,t}$	Power flow on transmission line (b,j) in scenario s, at period t
$\delta_{b,s,t}$	Voltage angle at bus b and in scenario s, at period t
$\widehat{\lambda}^e_{b,s,t}$	Local marginal electric price at bus b in scenario s, at period t.
$\widehat{\lambda}^G_{n,s,t}$	Local marginal gas price at node n in scenario s, at period t.
$\nu_{sp,s,t}$	NG producer sp at scenario s at period t
$Pr_{n,s,t}$	Pressure at node n in scenario s at period t
$h_{n,m,s,t}$	Average mass of NG (linepack) in pipeline (n,m), scenario s, at period t

$q^{in/out}_{n,m,s,t}$	Inflow/ outflow NG rates of the pipeline (n,m) in scenario s, at period t
$v^{e}_{in,h,s,t}$, $v^{g}_{in,h,s,t}$	Electricity and NG input for energy hub h in scenario s, at period t
$v^{h}_{out,h,s,t}$	Heating output for energy hub h in scenario s, at period t
$v_{1\cdots17,h,s,t}$	The energy flow of energy hub h in scenario s, at period t
$EL^{e}_{h,s,t}$, $EL^{g}_{h,s,t}$	Electricity/ NG loads of energy hub h in scenario s, at period t
$EL^{h}_{h,s,t}$	Heating load of energy hub h in scenario s, at period t
$EY_{h,s,t}$	Storing indicator for electricity of energy hub h in scenario s, at period t. If the condition is 1, the electricity storage is charged, if the condition is 0, the electricity storage is discharged
$HY_{h,s,t}$	Storing indicator for heating of energy hub h in scenario s, at period t. If the condition is 1, the heating storage is charged, if the condition is 0, the heating storage is discharged
$\Delta ES_{h,s,t}$, $\Delta HS_{h,s,t}$	Changes of electric / heat stored in electric / heat storage of energy hub h in scenario s, at period t
$L_{l,s,t}$	NG load l in scenario s, at period t
$\alpha^{K}_{h,s,t}$	Combined coefficient for corner point k of CHP in energy hub h in scenario s, at hour t

1. Introduction

1.1. Motivation

A multi-energy system (MES) is a relatively new development that has attracted more attention from researchers in recent years due to an increase in renewable energy sources (RESs) all over the world. In a MES, several energy carriers such as electricity, gas, heat, and cooling are considered together. This energy diversification enhances system reliability, flexibility, and stability. In addition, the benefits of integrating different energies create new challenges to system performance. With the development of multi-energy carriers, participants in the energy markets are increasing. Now the question that comes up here is "do traditional markets respond to this volume of different energies? "Traditionally, various energy sources are managed by different independent operators. However, recent studies have focused on operator coordination methods [1]. Some energy types such as electricity and natural gas (NG) can be transported over long distances (a few hundred kilometers). However, the heat and cooling just can be produced and consumed in a limited area. Therefore, MES includes region level (transmission) and local level (distribution) systems. At the regional MES, gas-fired power plants (GFPPs) are responsible for the coordination of the NG network and electricity grid. Producing electricity by GFPPs with high-efficiency, fast start-up and high-ramping can be one of the best options to counter with the inherent uncertainty of RESs. In addition to the technical benefits, the GFPPs does not produce any NOx gas, and its SO2 emissions are substantially lower than the coal and oil power plants [2]. World-wide, the demand for gas to generate electricity usually reaches above 40% of total gas fuel consumption, which is expected to increase in the coming years [3]. This fact indicates the creation of a deep connection between power systems and NG systems. With this growing trend of power generation with GFPPs, significant challenges for the performance of the two systems have been created. One of the challenging problems is how to coordinate the electricity and NG markets. From the perspective of the electricity market operator, the generation of electricity by GFPPs has led to that the gas market prices directly affecting the unit commitment (UC) [4].

1.2. Literature review

Some literature has focused on the connection between electricity and NG networks at regional levels. The effects of the gas network on the UC model has been analyzed in [4–6]. Authors of [7] has investigated a market-clearing model considering the electricity and NG network constraints. The proposed model was solved by a two-stage stochastic UC and taking into account the effect of compressed air storage unit on the system flexibility. Authors of [8] have proposed (i) the information decision gap theory (IGDT)-based robust security UC for coordinated power and NG systems with integrating compressed air energy storage system (CAES) and (ii) the concept of demand response (DR) for day-ahead planning considering flexible ramping products for ensure system reliability. In [9], a minimax-regret robust flexibility-constrained UC model has been considered for increasing the flexibility of the electric power distribution and NG system (IDGS). The authors have presented a multi-objective scheduling based on the UC in [10] for integrated electricity and NG networks, considering flexible energy sources such as P2G system and DR. In [11], a MILP problem has been proposed to integrate the electricity and NG markets under a two-stage stochastic approach. The aim of this work was to compare the operation of the NG network and electrical grid in independently and integrated manner. The results show that the operating costs are reduced when the electrical grid and NG network are operated in an integrated manner. The authors of [12] have proposed a UC scheduling on integrated electricity and NG systems considering flexible energy sources such as P2G, electricity and NG storage systems and linepack technology. A decentralized decision making strategy for multi-area integrated electricity and NG systems has been presented in [13]. In this literature, both electricity and NG operators decide independently. Authors of [14] have proposed a market-based stochastic approach for the energy market clearing in interconnected electricity and NG networks considering wind power. In [15], a co-planning of electricity and NG networks considering the uncertainties of grid loads has been provided. Authors of [16] have evaluated the impact of local marginal prices on the bilateral trade between electricity and NG markets at the distribution level. Also, in this research, a second-order cone programming (SOCP) approach has been used to solve the problem of optimal multi-period NG and obtain the market clearing price. Authors of [17] have proposed a stochastic bi-level model to optimally define the volume of NG for power generation planning, which can predict real-time energy demands. The authors of [18] have proposed a bi-level approach for modeling the equilibrium of the coupled electricity and NG markets, where a special diagonalization algorithm (DA) has been designed to solve the interaction between two markets. The authors of [19] have presented an equilibrium problem with equilibrium constraints (EPEC) to study the clearing of independent power and NG markets under optimal offering strategies and market powers of energy producers considering a DA algorithm to solve the problem. In [20], a bi-level approach for modeling the equilibrium of the electricity and NG markets under strategic offering and bidding behaviors is presented, where the upper level includes several strategic firms, and the lower level of the problem consider two markets of electricity and NG. The authors of [21] have proposed an optimization problem for electricity, NG, and district heat networks with the aim of minimizing operating costs under the IGDT approach for modeling the uncertainty of energy resources.

Local-level MES is modeled as a composite of many independent subsystems (electricity, NG, district heat, and water) where energy subsystems are independently operated. To meet various local level loads, the function of the local MES is to convert the electricity and NG delivered by the regional MES to heat and cooling. The local MES operation method focuses on energy conversion and storage and distribution methods instead of network optimization at distribution levels. However, it is difficult to build energy distribution and conversion across all of the equipment due to a great number of energy conversion equipment, as well as energy storage resources in local MES. As such, the energy hub is presented to model the interface between energy distribution and conversion in a local MES, based on coupling matrices [1, 22]. The literature related to the local level or energy hub problems are extensive. These problems have been used under different contexts, such as investigating a variety of hub energy modeling [23], Providing a variety of optimal methods for energy hub management [24], investigating the impact of different energy storage systems on energy hubs and microgrid [25, 26], and comprehensive evaluation of the impact of different types of uncertainty modeling on energy hubs is provided in [27].

The authors of [28] have proposed a multi-objective scheduling for an EH with the aim of maximizing social welfare and minimizing the CO2 emissions by considering the genetic algorithm to solve this optimization problem. Reference [29] has been presented a stochastic programming model developed for multi-energy systems integrated with active distribution grid and NG network and energy hubs. In [30] has been presented a study on the impact of integrating electric vehicles (EV) and demand responsiveness program on a comprehensive energy hub under a robust optimization approach. In [31], a regional-district scheduling is proposed based on two-stage robust optimization aiming at increasing the level of penetration of wind power generation. This work has been extended in [32] by assessing the impact of natural disasters on the regional-district system on the previous problem. Moreover, how power to gas (P2G) behaves have been analyzed when one of the working network pipelines is out of circulation. In [33], a two-level optimization problem for the day ahead planning of active distribution systems equipped with renewable energy sources, distributed generation units, energy storage systems and electric vehicles has been presented. In [34], the authors have proposed an optimal bi-level program to study the economic interaction between energy hub systems and the electricity distribution network with the aim of minimizing the costs of the energy hub system and the electricity distribution network. In [35], the authors have presented a MPEC to investigate the strategic behavior of the energy hub system in integrated power and heating markets with the aim of increasing the profitability of the energy hub system. In [36], the authors have proposed mixed-integer nonlinear programming to integrate smart energy hubs into the distribution network considering hybrid uncertainty-based DR schemes.

In [37], an optimal risk-constrained planning for a smart energy hub is provided with flexible resources such as CAES system and DR program. Authors in [38] have introduced a new modeling approach to optimize the power energy management of a multi-energy micro grid considering of the DR program and uncertainty of energy hubs loads. In [39] a stochastic-interval hybrid approach for robust programming of an energy hub is presented. In addition, a thermal and electric DR program is used to save energy costs on the energy hub. In [40], an optimal scheduling is provided for supplying electric, heating and cooling loads with continuous and (on / off) controllable loads. In addition, the features of energy hub forming equipment such as energy losses, cooling degradation cost, cooling and heating storage, combined heat and power (CHP) are taken into account. In [41] a stochastic model is presented for the electricity and NG real-time prices of an energy hub. In this research, to manage the system uncertainty, Conditional-Value-at-Risk (CVaR) technique is used to control the risk in the operation of energy hubs. In [42], a multi-objective scheduling has been implemented to minimize operating costs and reduce carbon emissions in the presence of a DR program on an energy hub. The results of this study show that the implementation of the DR program reduces the operating costs and carbon emissions. The authors of [43] have proposed a robust scheduling for optimizing a hydrogen-based micro-energy hub, taking into account the DR program and the fuel cell-based hydrogen storage system.

1.3. Contributions

To the best knowledge of the authors, in above researches has not been discussed how to connect the markets at regional and local levels. In other words, the focus of previous works is often on how to coordinate regional market systems or only local systems independently. The main gaps in the reviewed literature can be summarized as follows:

- In some works, e.g. [7-21], researchers have focused only on the coordination of NG and electricity systems at the regional level. They have not analyzed the impact of regional-level parameters on the local level system.
- In some works, e.g. [23-27, 30, 37-43], researchers have focused only on the optimal scheduling of energy hub systems. They have refrained from modeling the wholesale market for the purchase of electricity and NG to supply the demands of energy hub systems.
- In some works, e.g. [7, 8, 10, 12-17, 21], the problem of optimal scheduling of integrated electricity and NG systems at the regional level without considering the linepack system has been investigated. The existence of linepack system in NG networks is beneficial and increases the flexibility of NG systems and generation units, especially in critical times of the NG network. In addition, the linepack system reduces the total operating costs of the integrated electricity and NG system. Also, the linepack system can have a positive effect on the local level system.
- In some works e.g. [29, 31, 32], the authors focus on coordinating local and regional levels in a centralized manner. In a decentralized approach, private data operation of both local and regional level systems is more preserved.
- In some works, e.g. [33-36], the authors have focused on the physical or economic interactions of hub energy systems with the distribution or transmission power network and ignore the constraints of the NG network. Given

that NG energy is one of the main inputs for energy hub systems [23], ignoring the constraints of the NG network leads to inaccurate results.

To cover these gaps, in this paper, a decentralized stochastic approach to evaluate the impact of EES on regional-local MES market-clearing within a two-step iteration-based framework is provided. The main contributions of this paper are summarized as follows:

- A bi-level stochastic market-clearing mechanism is established to model economic interaction between regional and local level system operators.
- A two-step iteration-based framework is proposed to solve the bi-level optimization problem, where the interaction effect of the regional and local level systems on each other are considered.
- The effect of local-level energy storage resources on the market-clearing price of local and regional level systems is evaluated considering uncertainty of local level demands.
- The effect of the flexibility of the NG system equipped with linepack technology on the dispatch of regional level generation units and the optimal scheduling of the local energy system is investigated.

The rest of the paper is organized as follows: (i) the second section of the paper deals with problem description and formulation, (ii) the third section of the paper revolves around the case studies and obtained results, and (iii) finally, the conclusion is written in Section 4 of the paper.

2. Problem description and formulation

2.1. Introducing the precise concept for regional-local MES modeling

The concept of regional-local MES is presented in Figure 1. Regional MES coordinates the production and dispatch of electricity and NG systems at transmission levels. At the regional level system, integrated electricity and NG systems are managed by a centralized system operator (CSO). The local MES plans the electricity and NG delivered by the regional MES to supply heat, gas, and electrical loads. The local level system is controlled by an energy hub operator (EHO). The regional MESs

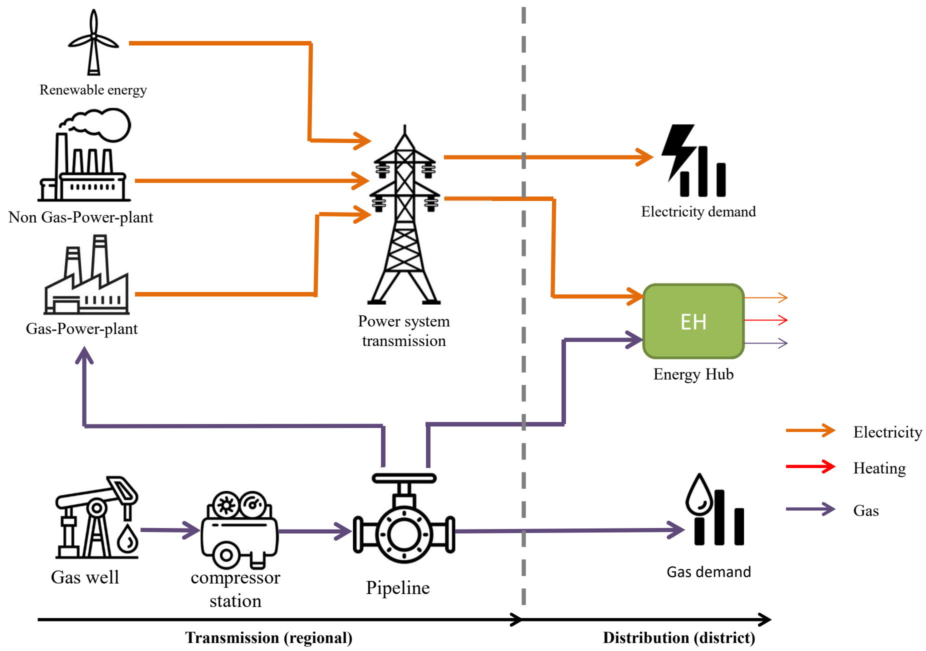

Figure 1: Regional-local MES structure

is physically coordinated between the two systems through the NG consumption of GFPPs. While they are economically coordinated through the NG price offered to the GFPPs. Figure 2 illustrates the energy hub structure for the local MES. In this local MES structure, it is equipped with combined heating and power (CHP), electrical boiler (EB), electrical storage (ES), heating storage (HS). The energy hub model can be simply expanded to use other equipment such as air storage systems and NG furnaces.

2.2. *Mathematical modeling of regional MES market clearing (lower level problem)*

The EHO goal in this problem is to minimize the operating costs (costs of purchasing electrical and NG energies from the regional level) in a two-step iteration-based framework to meet different local-level demands, with considering security constraints and uncertainties of different local level loads.

$$\min \sum_{s} \pi_s \sum_{t} \sum_{h} (\rho^{LMPES}_{s,t} v^{e}_{in,h,s,t} + \alpha^{LMGES}_{s,t} v^{g}_{in,h,s,t}) \tag{1}$$

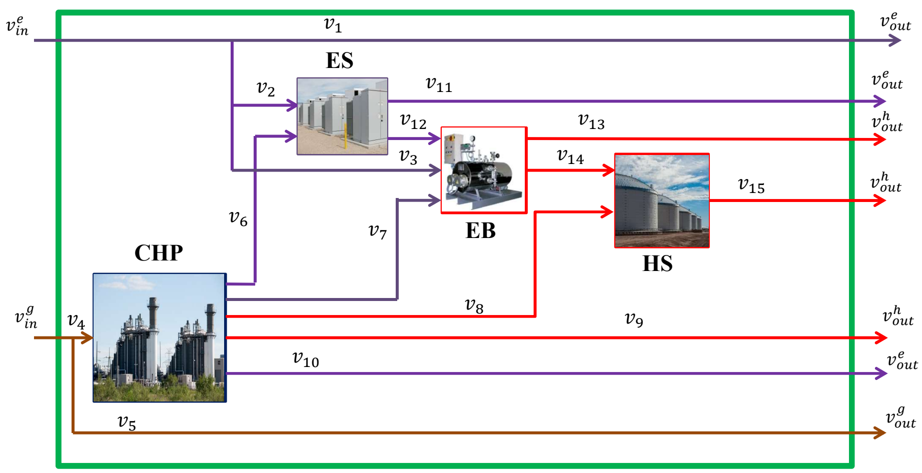

Figure 2: Energy hub structure for local MES

Eq. 1 determines the local-level objective function that our aim is to minimize the costs of operating electrical and NG energies purchase at the regional level.

2.2.1. *Local-level technical and security constraints*

Eq. (2) specifies energy hub input energies. The offered energy hub is an oriented graph with one-way energy flux in each segment. Hence all variables $\nu_{1,h,s,t}$, $\nu_{2,h,s,t}$, $\cdots$, $\nu_{17,h,s,t}$ in Eq. 3, are positive. Constraints (4) and (5) respectively represent the inputs of CHP and EB. Eqs. (6)-(8) represent the feasible operating area of the CHP unit. It is assumed that the CHP unit operates in the back pressure mode. Refer to [44] for more information on how to linearize CHP unit equations. Eqs. (9)-(11) state the balance of energy hub output power [31].

$$\nu^{e}_{in,h,s,t}, \nu^{g}_{in,h,s,t} \geqslant 0 \quad \forall h, \forall s, \forall t \tag{2}$$

$$\nu_{1,h,s,t}, \nu_{2,h,s,t}, \ldots, \nu_{17,h,s,t} \quad \forall h, \forall s, \forall t \tag{3}$$

$$\nu_{4,h,s,t} \leqslant CHP^{MAX}_{h} \quad \forall h, \forall s, \forall t \tag{4}$$

$$\nu_{3,h,s,t} + \nu_{7,h,s,t} + \nu_{12,h,s,t} \leqslant EB^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{5}$$

$$\nu_{7,h,s,t} + \nu_{10,h,s,t} = \sum_{K} \alpha^{K}_{h,s,t} y^{K}_{h} \quad \forall h, \forall s, \forall t \tag{6}$$

$$0 \leqslant \alpha^{K}_{h,s,t} \leqslant 1 \quad \forall h, \forall s, \forall t, \forall k \tag{7}$$

$$\sum_{K} \alpha^{K}_{h,s,t} = 1 \quad \forall h, \forall s, \forall t \tag{8}$$

$$\nu^{e}_{out,h,s,t} = EL^{e}_{h,s,t} \quad \forall h, \forall s, \forall t \tag{9}$$

$$\nu^{g}_{out,h,s,t} = EL^{g}_{h,s,t} \quad \forall h, \forall s, \forall t \tag{10}$$

$$\nu^{h}_{out,h,s,t} = EL^{h}_{h,s,t} \quad \forall h, \forall s, \forall t \tag{11}$$

2.2.2. Local level heat storage system constraints

Eq. (12) constraints the HS output and input. Eq. (13) indicates that charging and discharging the HS cannot be done simultaneously. Eqs. (14) and (15) enforce the heat energy of HS. Since our focus is on scheduling the day-ahead market clearing of the regional and local level system, accurately model the losses in the energy storage systems is ignored [31].

$$\nu_{8,h,s,t} + \nu_{14,h,s,t} \leqslant HY_{h,s,t} HC^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{12}$$

$$\nu_{15,h,s,t} \leqslant (1 - HY_{h,s,t}) HD^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{13}$$

$$HS_{h,s,t} = \begin{cases} HS_{h,s,0} \quad t = 0 \\ HS_{h,s,t-1} + \Delta HS_{h,s,t-1} \quad O.W \end{cases} \quad \forall h, \forall s, \forall t \tag{14}$$

$$0 \leqslant HS_{h,s,t} \leqslant HS^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{15}$$

2.2.3. Local level electrical storage system constraints

Eq. (16) limits the ES output and input. ES is not able to charge and discharge electrical at the same time in Eq. (17). Eqs. (18) and (19) enforce the electrical energy of ES [31].

$$\nu_{2,h,s,t} + \nu_{6,h,s,t} \leqslant EY_{h,s,t} SC^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{16}$$

$$\nu_{11,h,s,t} + \nu_{12,h,s,t} \leqslant (1 - EY_{h,s,t}) SD^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{17}$$

$$ES_{h,s,t} = \begin{cases} ES_{h,s,0} \quad t = 0 \\ ES_{h,s,t-1} + \Delta ES_{h,s,t-1} \quad O.W \end{cases} \quad \forall h, \forall s, \forall t \tag{18}$$

$$0 \leqslant ES_{h,s,t} \leqslant ES^{Max}_{h} \quad \forall h, \forall s, \forall t \tag{19}$$

2.2.4. The standardized matrix representation of local level

The standard local level matrix showing the relationship between the inputs and outputs of different energy carriers is illustrated Eq. (20) [31].

$$
\begin{bmatrix}
0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 1 & 0 & 1 \\
-1 & 0 & 0 & 0 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & -1 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & -1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \eta_{HC} & 0 & 0 & 0 & 0 & 0 & \eta_{HC} & \frac{1}{\eta_{HC}} \\
0 & 0 & 0 & -1 & 0 & \eta_{SC} & 0 & 0 & 0 & \eta_{SC} & 0 & 0 & 0 & 0 & \frac{-1}{\eta_{Sd}} & \frac{-1}{\eta_{Sd}} & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & \eta_{Ce} & 0 & -1 & -1 & 0 & 0 & -1 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & \eta_{Cg} & 0 & 0 & 0 & -1 & -1 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & \eta_{eb} & 0 & 0 & 0 & \eta_{eb} & 0 & 0 & 0 & 0 & \eta_{eb} & -1 & -1 & 0
\end{bmatrix}
\begin{bmatrix}
{}^{e}_{in,h,t,s} \\
v^{g}_{in,h,t,s} \\
\Delta HS_{h,t,s} \\
\Delta ES_{h,t,s} \\
v_{1,h,t,s} \\
v_{2,h,t,s} \\
v_{3,h,t,s} \\
v_{4,h,t,s} \\
v_{5,h,t,s} \\
v_{6,h,t,s} \\
v_{7,h,t,s} \\
v_{8,h,t,s} \\
v_{9,h,t,s} \\
v_{10,h,t,s} \\
v_{11,h,t,s} \\
v_{12,h,t,s} \\
v_{13,h,t,s} \\
v_{14,h,t,s} \\
v_{15,h,t,s}
\end{bmatrix}
=
\begin{bmatrix}
{}^{e}_{out,h,t,s} \\
v^{g}_{out,h,t,s} \\
0 \\
0 \\
0 \\
0 \\
0 \\
0 \\
0 \\
0
\end{bmatrix}
\tag{20}
$$

2.3. Mathematical modeling of regional MES market clearing

The aim of CSO in this problem is to clear the electricity and NG market with a stochastic approach to determine the local marginal price (LMP) values of offered to the local level.

Eq. (21) relates to the objective function of the problem that our aim is to minimize the costs of operating the electricity and NG systems. Eq. (22) is the quadratic cost of generation NGFPP in the UC. Since the quadratic cost of generation is non-linear, it is linearized using the method presented in [45].

$$\min \sum_{s} pi_s \sum_{t} \sum_{i \in CU} (FC_{i,s,t} + SU_{i,t}^{s} + SD_{i,t}^{s}) + \sum_{sp} \gamma_{gas} V_{sp,s,t} \tag{21}$$

$$FC_{i,s,t} = a_i P_{i,s,t}^2 + b_i P_{i,s,t} + c_i I_{i,t}^{s} \quad \forall i \in CU, \forall s, \forall t \tag{22}$$

The first term of the equation is about the operating cost and startup/shut down the power plants due to the cost of generating electricity from Non gas-fired power plant (NGFPP). The second term is related to the cost of gas production (gas well). Note that the electricity and NG networks are cleared by the CSO under an objective function so because of that the cost of generating the GFPPs electricity is not included because this would double the cost.

2.3.1. Generating unit constraints

Eq. (23) relates to the limitation of power units generation. Eqs. (24) and (25) are related to the costs of startup and shut down NGFPP. Eqs. (26) and (27) are related to the costs of startup and shut down of GFPPs. Eqs. (28) and (29) sets the startup/ shutdown status of all units. Eqs. (30) and (31) are related to the ramp-up/down rate variations of the generating power of the units.Eqs. (32)- (37) related to the minimum on/off time.

$$P_i^{Min} I_{i,t}^{s} \leqslant P_{i,s,t} \leqslant P_i^{Max} I_{i,t}^{s} \quad \forall i, \forall s, \forall \tag{23}$$

$$SU_{i,t}^{s} = C_i^{SU} y_{i,t}^{s} \quad \forall i \in CU, \forall s, \forall t \tag{24}$$

$$SD_{i,t}^{s} = C_i^{SD} z_{i,t}^{s} \quad \forall i \in CU, \forall s, \forall t \tag{25}$$

$$GSU^s_{i,t} = C^{GSU}_i y^s_{i,t} \quad \forall i \in GU, \forall s, \forall t \tag{26}$$

$$GSU^s_{i,t} = C^{GSU}_i z^s_{i,t} \quad \forall i \in GU, \forall s, \forall t \tag{27}$$

$$y^s_{i,t} - z^s_{i,t} = I^s_{i,t-1} - I^s_{i,t} \quad \forall i, \forall s, \forall t \tag{28}$$

$$y^s_{i,t} + z^s_{i,t} \leqslant 1 \quad \forall i, \forall s, \forall t \tag{29}$$

$$P_{i,s,t} - P_{i,s,t-1} \leqslant (1 - y^s_{i,t}) R^{UP}_i + y^s_{i,t} P^{Min}_i \quad \forall i, \forall s, \forall t \tag{30}$$

$$P_{i,s,t-1} - P_{i,s,t} \leqslant (1 - z^s_{i,t}) R^{DN}_i + z^s_{i,t} P^{Min}_i \forall i, \forall s, \forall t \tag{31}$$

$$L^{on}_i = \min \left\{ T, (T^{on}_i - T^{on}_{i,0}) I^s_{i,0} \right\} \tag{32}$$

$$L^{off}_i = \min \left\{ T, (T^{off}_i - T^{off}_{i,0})(1 - I^s_{i,0} \right\} \tag{33}$$

$$\sum_{t \in L^{on}_i} 1 - I^s_{i,t} = 0 \quad \forall i, \forall s \tag{34}$$

$$\sum_{t=r}^{t+T^{on}_i - 1} I^s_{i,r} \geqslant T^{on}_i (I^s_{i,t} - I^s_{i,t-1}) \quad \forall i, \forall s, \forall t \in [L^{on}_i + 1, T - T^{on}_i + 1] \tag{35}$$

$$\sum_{t=r}^{T} (I^s_{i,r} + (I^s_{i,t} - I^s_{i,t-1})) \geqslant 0 \quad \forall i, \forall s, \forall t \in [T - T^{on}_i + 2, T] \tag{36}$$

$$\sum_{t \in L^{off}_i} I^s_{i,t} = 0 \quad \forall i, \forall s \tag{37}$$

$$\sum_{t=r}^{t+T^{off}_i - 1} (1 - I^s_{i,r}) \geqslant T^{off}_i (I^s_{i,t-1} - I^s_{i,t}) \quad \forall i, \forall s, \forall t \in \left[L^{off}_i + 1, T - T^{off}_i + 1\right] \tag{38}$$

$$\sum_{t=r}^{T} (1 - I^s_{i,r} + (I^s_{i,t-1} - I^s_{i,t})) \geqslant 0 \quad \forall i, \forall s, \forall t \in \left[T - T^{off}_i + 2, T\right] \tag{39}$$

2.3.2. Power network constraints

Eq. (40) is related to the bus power balance equation. Eq. (41) is related to the constraint of the line flow and Eq. (42) corresponds to the DC load flow in the power system.

$$\sum_{j:(b,j) \in Tr} f_{b,j,s,t} = \sum_{i \in A^i_b} P_{i,s,t} + \sum_{w \in A^w_b} PW_{w,s,t} - \sum_{h \in A^h_b} \nu^e_{in,h,s,t} - \sum_{d \in A^d_b} D_{d,t} : \widehat{\lambda^e_{b,s,t}} \quad \forall b, \forall s, \forall t \tag{40}$$

$$-f^{Max}_i \leqslant f_{b,j,s,t} \leqslant f^{Max}_b \quad \forall (b,j) \in Tr, \forall s, \forall t \tag{41}$$

$$f_{b,j,s,t} = (\delta_{b,s,t} - \delta_{j,s,t}) / X_L \quad \forall (b,j) \in Tr, \forall s, \forall t \tag{42}$$

2.3.3. NG system constraints

Like bus voltage constraints in the power grid, the node pressure constraints in the NG network must be guaranteed in a suitable range Eq. (43) that is guaranteed to customers. According to Eq. (44), the flow of NG can be expressed as a function of the squared pressure and pipe characteristics such as length, diameter, and coefficient of friction. This equation is known as the general flow equation, which can be approximated by Weymouth equations under certain conditions. The sign function in Eq. (45) allows the flow from both sides, for example, it is possible according to the pressure values in the gas flow pipelines be from n to m or vice versa. Eq. (44) is non-convex in addition to being nonlinear.

$$Pr_n^{Min} \leqslant Pr_{n,s,t} \leqslant Pr_n^{Max} \quad \forall n, \forall s, \forall t \tag{43}$$

$$q_{n,m,s,t} = sgn(Pr_n, Pr_m) K_{n,m}^f \sqrt{Pr_{n,s,t}^2 - Pr_{m,s,t}^2} \quad \forall (n,m) \in z, \forall s, \forall t \tag{44}$$

$$sgn(Pr_n, Pr_m) = \begin{cases} 1, & Pr_n \geqslant Pr_m \\ -1, & Pr_n \leqslant Pr_m \end{cases} \quad \forall (n,m) \in z \tag{45}$$

Nonlinearity and non-convexity of the gas flow equation make it difficult for natural gas pricing. Therefore, we used an outer approximation approach based on the Taylor series expansion around fixed pressure points to linearize the Weymouth equation and propose a globally optimal solution [9]

$$q_{n,m,s,t} \leqslant \frac{K_{n,m}^f PR_{n,u}}{\sqrt{PR_{n,u}^2 - PR_{m,u}^2}} Pr_{n,s,t} - \frac{K_{n,m}^f PR_{m,u}}{\sqrt{PR_{n,u}^2 - PR_{m,u}^2}} Pr_{m,s,t} \quad \forall (n,m) \in z, \forall s, \forall t \tag{46}$$

where u is a set of fixed pressure points $PR_{n,u}$, $PR_{m,u}$ [46]. However, the constraint of the gas flow is given by Eq. (46). The sgn function is ignored because of the nonlinearity of the above equation. Therefore, an equation must be defined that it guarantees the two-way flow of gas in the pipeline. Therefore, Eqs. (47)-(50) is used to ensure the two-way flow of the system [11].

$$q_{n,m,s,t} = q_{n,m,s,t}^+ - q_{n,m,s,t}^- \quad \forall (n,m) \in z, \forall s, \forall t \tag{47}$$

$$q_{n,m,s,t}^+ \leqslant M y_{n,m,s,t} \quad \forall (n,m) \in z, \forall s, \forall t \tag{48}$$

$$q_{n,m,s,t}^- \leqslant M(1 - y_{n,m,s,t}) \quad \forall (n,m) \in z, \forall s, \forall t \tag{49}$$

$$y_{n,m,s,t} \in \{1, 0\} \quad \forall(n, m) \in z, \forall s, \forall t \tag{50}$$

where $q^{+}_{n,m,s,t}$ illustrates the gas flow in the pipeline from node n to node m and similarly $q^{-}_{n,m,s,t}$ illustrates the gas flow from node m to node n. The parameter M is a large enough constant. Eq. (50) fulfills the function of sgn. Eqs. (51)-(52) ensure that only one of the two variables $q^{-}_{n,m,s,t}$ and $q^{+}_{n,m,s,t}$ has a different value from zero. In addition to the above constraints, the following inequalities are defined [11, 47]:

$$q^{+}_{n,m,s,t} \leqslant \frac{K^{f}_{n,m} PR_{n,u}}{\sqrt{PR^{2}_{n,u} - PR^{2}_{m,u}}} \underset{n,s,t}{Pr} - \frac{K^{f}_{n,m} PR_{m,u}}{\sqrt{PR^{2}_{n,u} - PR^{2}_{m,u}}} \underset{m,s,t}{Pr} + M(1 - y_{n,m,s,t}) \quad \forall \langle n, m) \in z \mid m < n \rangle, u, s, t \tag{51}$$

$$q^{-}_{n,m,s,t} \leqslant \frac{K^{f}_{n,m} PR_{m,u}}{\sqrt{PR^{2}_{m,u} - PR^{2}_{n,u}}} \underset{m,s,t}{Pr} - \frac{K^{f}_{n,m} PR_{n,u}}{\sqrt{PR^{2}_{m,u} - PR^{2}_{n,u}}} \underset{n,s,t}{Pr} + M(y_{n,m,s,t}) \quad \forall \langle n, m) \in z \mid m > n \rangle, u, s, t \tag{52}$$

It can be seen that the gas flow direction is defined by binary variables, as given as appropriate linear Eqs. (53) and (54). Also, two non-negative variables $q^{in}_{n,m,s,t}$ and $q^{out}_{n,m,s,t}$ are defined for flexibility of linepacks in inflow and outflow [11].

$$q^{+}_{n,m,s,t} = \frac{q^{in}_{n,m,s,t} - q^{out}_{n,m,s,t}}{2} \quad \forall(n, m) \in z, \forall s, \forall t \tag{53}$$

$$q^{-}_{n,m,s,t} = \frac{q^{in}_{m,n,s,t} - q^{out}_{m,n,s,t}}{2} \quad \forall(n, m) \in z, \forall s, \forall t \tag{54}$$

One of the unique features of linepack in NG systems is that it can act as short-term storage and it is an economical way to save energy [11].

$$h_{n,m,s,t} = K^{f}_{n,m} \frac{Pr_{n,s,t} + Pr_{m,s,t}}{2} \quad \forall(n, m) \in z, \forall s, \forall t \tag{55}$$

$$h_{n,m,s,t} = h_{n,m,s,t-1} + q^{in}_{n,m,s,t} - q^{out}_{n,m,s,t} \quad \forall(n, m) \in z, \forall s, \forall t \geqslant 1 \tag{56}$$

$$h_{n,m,s,t} = h_{n,m,s,0} + q^{in}_{n,m,s,t} - q^{out}_{n,m,s,t} \quad \forall(n, m) \in z, \forall s, \forall t = 1 \tag{57}$$

$$h_{n,m,s,t} \geqslant h_{n,m,s,0} \quad \forall(n, m) \in z, \forall s, \forall t \tag{58}$$

Eq. (55) shows that the linepack corresponds to the average pressure of the pipeline. Therefore, by increasing the pressure at the node of a pipeline, it will increase the linepack and vice versa. Eqs. (56) and (57) also show that the linepack in addition to Eq. (55) is equal to the difference between inlet and outlet flow in the pipeline. Other technical constraints of the NG network are as follows:

$$\nu_{sp}^{Min} \leqslant \nu_{sp,s,t} \leqslant \nu_{sp}^{Max} \quad \forall sp, \forall s, \forall t \tag{59}$$

$$\sum_{sp \in A_n^{sp}} \nu_{sp,s,t} - \sum_{h \in A_n^h} \nu_{in,h,s,t}^{g} - \sum_{l \in A_n^l} L_{l,t} = \sum_{(n,m) \in z} (q_{n,m,s,t}^{in} - q_{m,n,s,t}^{out}) : \widehat{\lambda}_{n,s,t}^{G} \quad \forall n, \forall s, \forall t \tag{60}$$

$$L_{l,t} = \frac{a_i P_{i,s,t}^2 + b_i P_{i,s,t} + c_i + SU_{i,t}^s + SD_{i,t}^s}{HHV} \quad \forall l, \forall s, \forall t, \forall i \in GU \tag{61}$$

$$\widehat{\lambda}_{n,s,t}^{G} = \alpha_{s,t}^{LMGES} \quad \forall n = n_5, \forall s, \forall t \tag{62}$$

$$\widehat{\lambda}_{b,s,t}^{e} = \rho_{s,t}^{LMGES} \quad \forall b = b_5, \forall s, \forall t \tag{63}$$

Eq. (59) is related to the limitation of gas produced from NG wells. Eq. (60) is related to the balance of energy in NG production and consumption. Eq. (61) shows the coupling between the NG and power networks. Since Eq. (61) is nonlinear, it is linearized using the method presented in [45]. Where the higher heating value (HHV) is 1.026MBtu/kcf. Eqs. (62) and (63) are related to the electricity and NG prices offered local level, respectively.

2.4. Bi-level market-clearing mechanism

Figure 3 shows the market-clearing mechanism of local and regional levels. This mechanism consists of several participants, which are as follows:

1) NGFPP; the task of these units is to generate power through non-gas fuels and sells it to the power grid.

2)NG producers; the task of these producers is to extract NG from gas wells and then sell it to the NG network.

3) Renewable energy sources; the task of these sources is to generate power through non-fossil fuels such as wind, solar, biomass and sell it to the power grid.

4) CSO; this operator is responsible for controlling and overseeing the integrated electricity and NG networks, as well as clearing the wholesale market.

5) Multi-energy consumers; they buy power and NG from the integrated wholesale market to meet their demands. Energy consumers are divided into active and inactive consumers. The energy hub system is introduced as one of the main active consumers that can reduce overall operating costs by using flexible energy sources (such as energy storage systems). The energy hub system can also have a positive effect on the wholesale market. Given that inactive consumers at the local level do not react to the price offered by the wholesale market, our focus will be on the interaction between the EHO and the wholesale market.

Generally, based on the proposed framework, energy producers (NGFPP, renewable energy sources, and NG producers) offer price-quantity for supplying energy to the CSO operator. Also, active and inactive consumers bid the CSO the required energy demand. Then, the CSO clears the wholesale market using standard market-clearing tools to maximize social welfare and obtain the LMP for power system busses and NG network nodes. In the proposed approach, the interaction between CSO and EHO has been considered, where the EHO behaves as a large-scale consumer in the wholesale market. The EHO clears the market based on the forecasted prices and then participates in the wholesale market to supply the rest of the demand. After clearing the integrated wholesale market (coordinated power and gas markets), local marginal prices will be determined and sent to the EHO. Now, the EHO updates its demand based on the received LMP by optimal scheduling of energy hub resources. So, the EHO can change the LMP values in the wholesale market by changing the load consumption pattern. The main reason for this practice is the dependence between energy consumption and price. In addition, we provide a two-step iterative framework for solving the bi-level problem. In the upper level, optimal stochastic scheduling for the EHO under an energy hub framework is solved with the aim of minimizing the cost of operation. In the lower level, the electricity and NG markets are cleared under a coordinated framework, taking into account wind power and linepack technology. The consumer demand profile is determined in the upper-level problem, and the energy price values at different conditions will be determined in the lower level problem.

The proposed two-step iteration-based framework is presented by a recursive algorithm in Figure 4. The following steps describe the iteration-based two-step method to solve the decentralized day-ahead market-clearing of the coupled regional-local energy systems.

Stage 1: Collecting information and input parameters (e.g. CHP capacity, charging and discharging capacity of energy sources, etc.) and calculating the electricity and NG required by the local level and present it to the regional level.

Stage 2: Solving the problem of electricity and NG clearing market by CSO using Eqs. (22)-(63).

Stage 3: Obtaining the amount of local marginal prices $\rho_{s,t}^{LMEPS}$ and $\sigma_{s,t}^{LMGPS}$ using the Eqs. (40) and (60).

Stage 4: EHO economic dispatch using Eqs. 1- 21 and obtaining operational cost amount.

Stage 5: Updating local level load profile ($\nu_{in,h,s,t}^{e}$ and $\nu_{in,h,s,t}^{g}$).

Stage 6: Solving the electricity and NG market clearing by CSO using Eqs. (22)-(63) with updated data.

Stage 7: Update the local marginal prices $\rho_{s,t}^{LMEPS}$ and $\sigma_{s,t}^{LMGPS}$ by using the dual Eqs. (40) and (60).

Stage 8: Use the new load profiles and the values of updated LMPs to achieve the true value of the overall energy hub cost.

Stage 9: If the following stopping criterion is satisfied, we will move on to the next step, otherwise go back to **Step 4**. (Here, the k index corresponds to the iteration of the algorithm)

$$\left|\nu_{in,h,s,k,t}^{e,g} - \nu_{in,h,s,k-1,t}^{e,g}\right| \leqslant \varepsilon \tag{64}$$

Stage 10: Report the results.

Note that the most appropriate way to solve bi-level problems is to convert both lower and upper levels of the problem into a single-level problem. However, commonly the bi-level programming problem is complex and difficult to solve. In bi-level problems, when the lower level is a linear programming problem (LP), the Karush–Kuhn–Tucker (KKT) conditions can be used to convert the bi-level problem into a single-level problem [48]. However, when the lower level problem is a mixed integer linear problem (MILP), this method cannot be used. In this work, an economic dispatch and a simple model without binary variables of the NG system can be used as a linear LP problem for wholesale market modeling. However, the effects of the UC and ramp-rate constraints and effect of linepack in natural gas

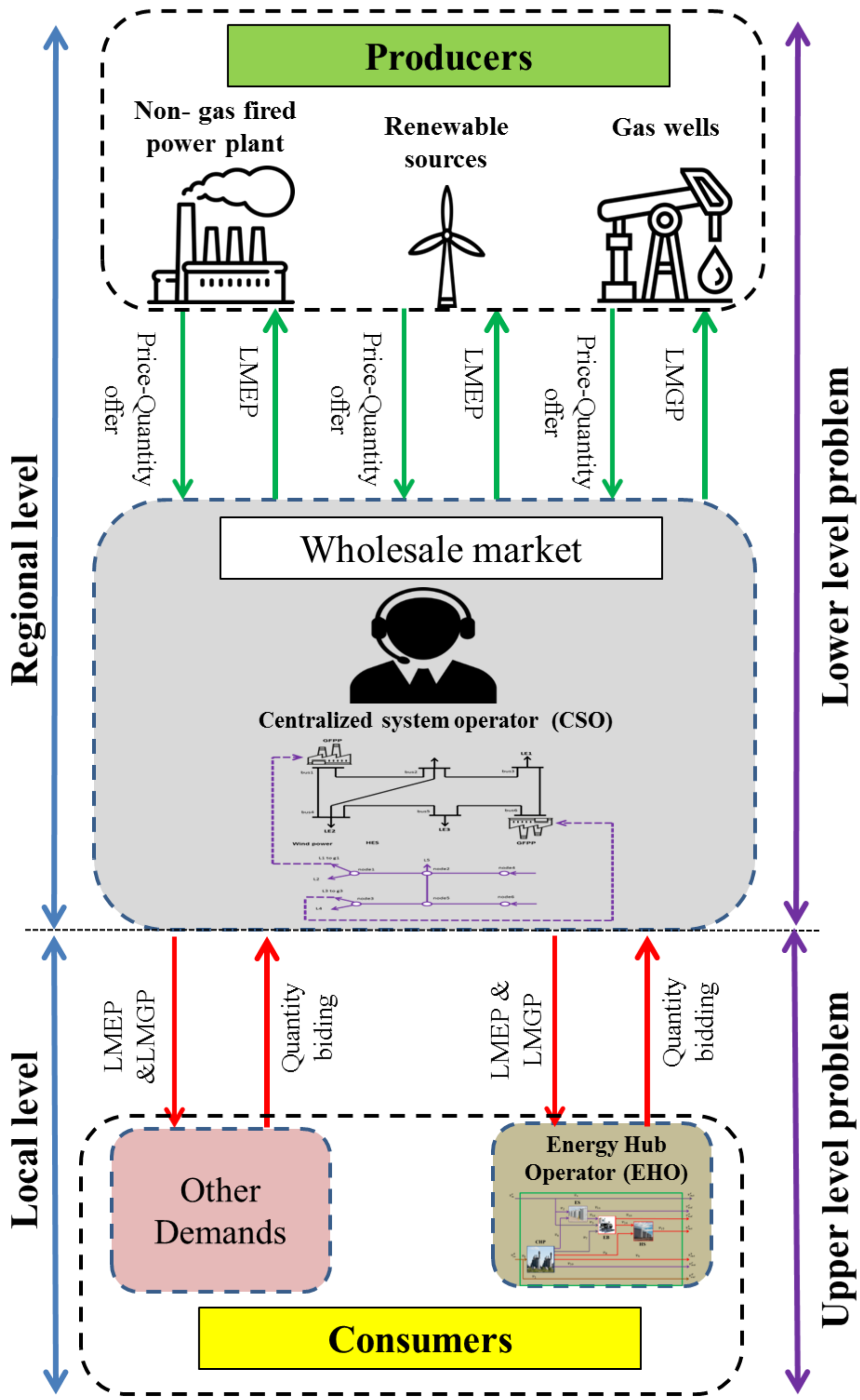

Figure 3: Market-clearing mechanism of local and regional levels

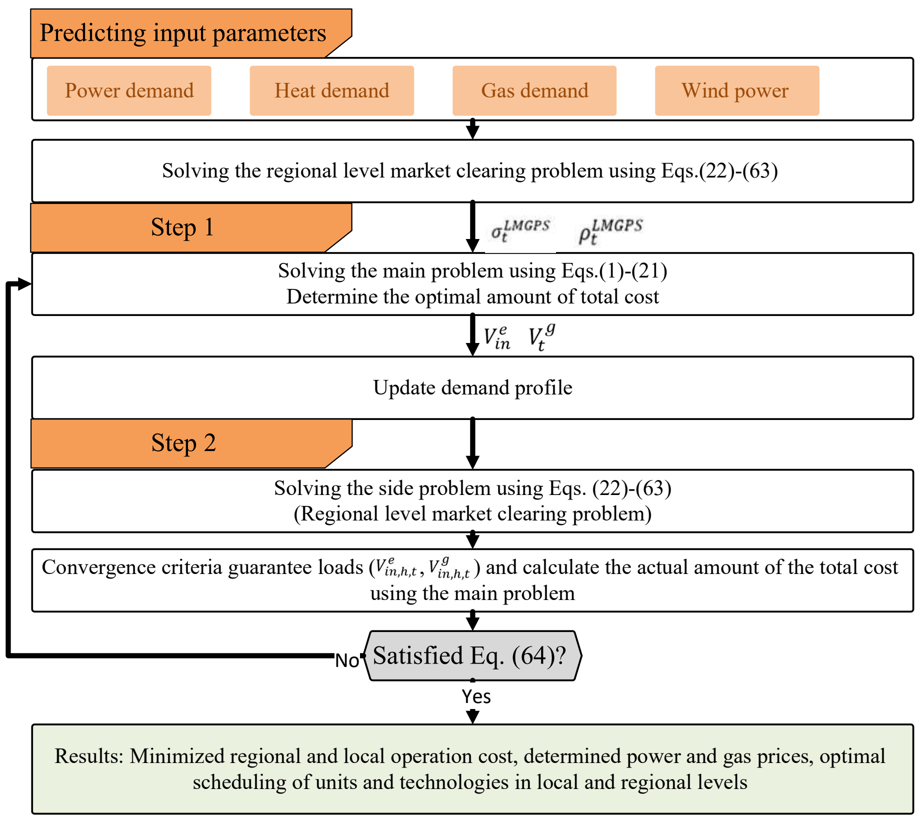

Figure 4: Proposed algorithm for the two-step iteration problem

system modeling are discarded. Discarding these constraints makes it impossible to provide a precise and accurate model for the modeling of integrated electricity and NG systems. Therefore, a two-step iteration-based framework can be used to solve such a problem. It should be noted that a similar two-step iteration method has been used in [49, 50].

3. Case study and results

In this paper, the proposed model has been simulated by using the IEEE 6-bus standard test system for the 6-bus power system and 6-node NG network. The performed case study has been analyzed in the form of three cases. The proposed problem is modelled as a MILP in GAMS software and has been solved using CPLEX standard solver. The modified 6-bus power system consists of two gas-fired, one non-gas-fired power plant and a wind power plant with seven transmission lines and two electric loads, which the characteristics of units, buses, transmission lines, and load profiles are provided in [51]. GFPPs are located at bus 1 and 6, and the NGFPP is located at bus 2 and wind power plan are located at bus 5. The 6-node NG network includes five pipelines, a compressor, two NG suppliers, and three residential NG loads. The topology of the local and regional level system has been depicted in Figure 5. The characteristics of NG wells, pipelines, and line packs have been provided in reference [52]. The values of CHP, EB, and EES parameters are presented in [31]. The gas load demand of the 6-node NG network (LG) and forecasted wind power dispatch has been shown in Figure 6. In addition, the local-level system (energy hub) is connected to the fifth bus of the power system, as well as the fifth node of the NG network. The electric, heat, and NG load profile of the local level have been indicated in Figure 7.

The considered case studies for analyzing MES at local and regional levels are as follows:

Case 1: Market clearing of the regional-local MES, without considering local EES and the uncertainties of local-level loads.

Case 2: Market clearing of the regional-local MES, considering the local EES

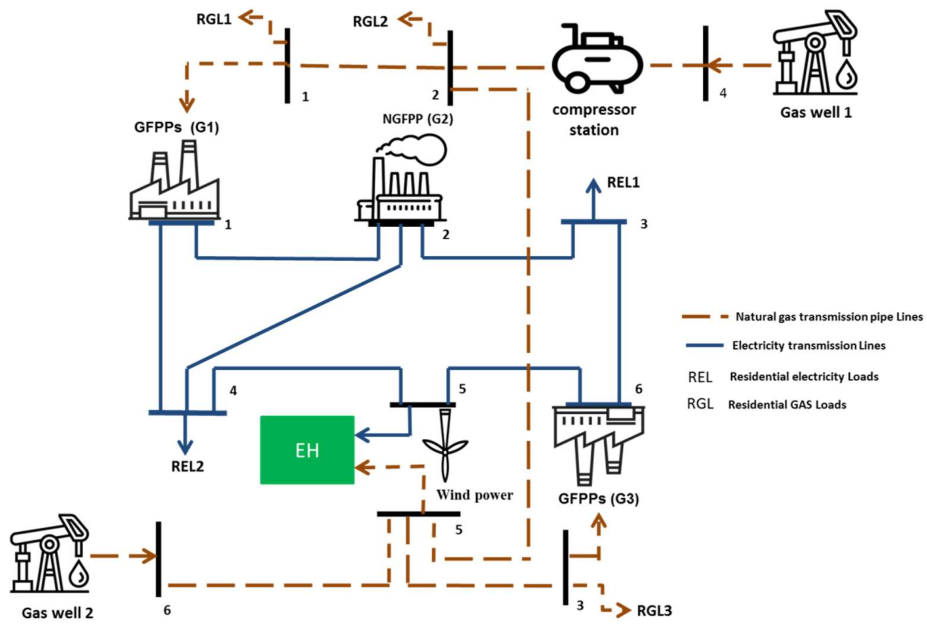

Figure 5: The topology of 6-bus power system with 6-node NG with local-level

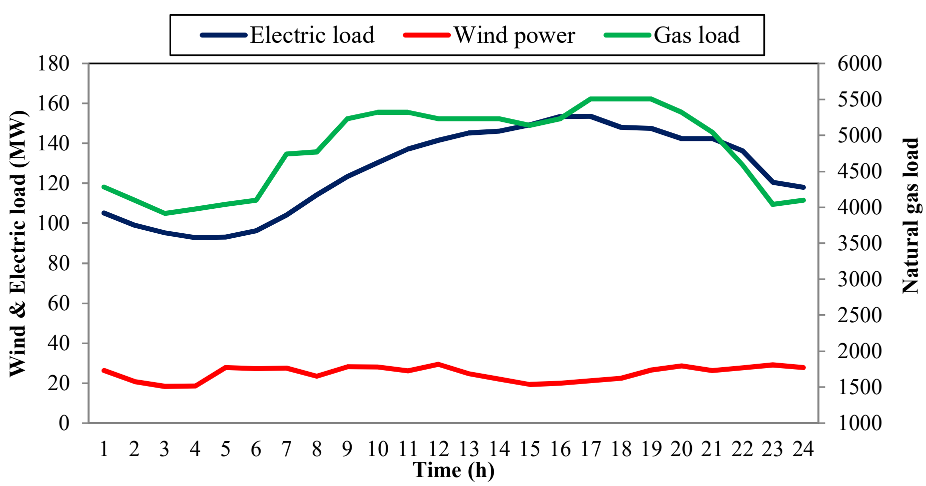

Figure 6: Forecasted total residential load of the NG network, electric network load and wind power generation at regional levels [11, 13]

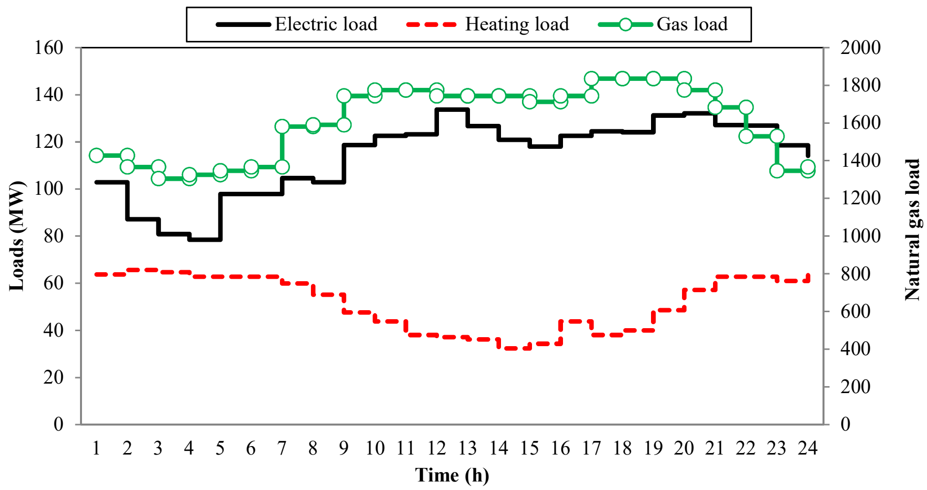

Figure 7: Hourly local level loads [32]

without the uncertainties of local-level loads.

Case 3: Market clearing of the regional-local MES, considering the local EES, as well as the uncertainties of local-level loads.

Case 1: In this case, the market clearing of the regional-local MES regardless of the local EES and their uncertainties is considered. The hourly scheduling of units' commitment has been indicated in Figure 8. As shown in this figure, the low-cost gas-fired unit G1 is in the entire time period in operation. While the expensive non gas-fired unit G2 enters the operation between hours 12 and 20. The generation unit G2 produces most of its output at peak load times of the power system and the NG network, which is between hours 13 and 19 in the power system and between hours 17 and 20 in the gas system, respectively. The gas-fired unit G3 also operates between hours 10 and 12, 20 and 23. In this case, the total operating costs, GFPPs and NGFPP are \$542908.27, \$534922.24 and \$43274.24, respectively. Also, the local level operating cost is \$166454.12

According to Figure 9, due to the low and uniform energy demand in the early hours (i.e. from 1 to 8 o'clock), the dispatch of the cheap G1 generation unit is low, so at these hours the market clearing price is 19.23 \$/MWh. From t=9 onwards, due to the increase in the dispatch of electricity in the G1 unit, the market clearing price will rise to 21.77 \$/MWh. Given that between hours 12 and 20, which is the peak hour load of the gas network and power grid, the NG system will restrict the gas dispatch to the GFPPs during these hours due to the prioritization of residential NG network loads over other NG network loads. As a result, the dispatch of the expensive unit G2 increased and the market clearing price changed to 30.01 \$/MWh. From 20:00 onwards, electricity and NG consumption will be reduced. Similarly, as energy demand declines, the dispatch of the G2 unit decreases, and therefore the market clearing price decreases to 24.56 \$/ MWh. Finally, from 23:00 onwards, with the reduction in the dispatch of cheap G1 and G2 units, the market clearing price will be reduced to 19.27 \$/MWh. It is worth noting that these results have been obtained by considering the capacity constraints of the transmission lines. Unless the capacity constraints are taken into account, the market clearing price will be the same across all power system buses. Given that expensive NG suppliers are online at all times, it is obvious that the market clearing price of the NG is regulated by expensive suppliers (i.e. 2.9 \$/Kcf).

Figure 10 shows the EHO scheduling to supply electrical loads in **Case 1**. From an economic point of view, due to the low price of NG, the entire electricity demand should be supplied by the CHP. Supplying the local-level loads by CHP has more priority than purchasing electricity from the grid, but ignoring both technical view and security constraints cause irreparable damage at both levels. Therefore, scheduling to meet the demands of different local level loads must be both economically and technically guaranteed. According to Figure 10, it can be seen that the local level electricity load supplied by the power grid and the CHP unit are 68.31% and 31.68%, respectively. As can be seen from Figure 10, the CHP generation capacity is reduced during on-peak times of the NG network.

Figure 11 explains how the hourly scheduling of energy hub to meet the local-level heating loads in **Case 1**. As attested by Figure 11, due to the low cost of producing heat energy from NG, EHO schedules to provide the largest heating loads by CHP. Because the local heating peak load, which is from t=1 to t=8 and t=20 to t=24, therefore heating energy production is limited by CHP. As a result, the EHO will have to purchase electricity from the EB during these hours to balance the production and consumption of local heating energy. According to Figure 11, it can be seen that the local level heat load supplied by the CHP and the EB are 91.66% and 8.34% respectively.

To evaluate the effect of linepack on the flexibility of NG network, the residential load of the NG network is increased by 15%. Since t=17 is experiencing a sudden increase in residential load on the NG network, this situation could be a critical area for power grid generating units. As a result, the linepack system is expected to provide flexibility for the integrated system in this condition and prevent increasing the power and gas prices. Figure 12 shows the impact of linepack flexibility on the G1 generating unit after a 15% increase in residential NG network loads. With the linepack system, the unit G1 can deliver 17.12% more power at peak hours. In other words, the existence of a linepack system prevents excessive reductions in the power output of the G1 at critical times. Figure 13 shows the impact of linepack flexibility on the G2 generating unit after a 15% increase in residential NG network loads. As can be seen from Figure 13, the unit G2 can provide 5% more power at the peak hour load of the NG network. In addition, it prevents expensive units from increasing in other hours. Additionally, as can be seen in Table 1, the existence of the linepack system in addition to increasing the flexibility of the regional level system reduces the operating costs of both local and regional levels.

Table 1: Comparison of operating costs of the whole system of local and regional levels with linepack and without linepack

	With linepack	Without linepack
Total cost ($)	590738.1405	591370.7491
GFPPs ($)	568624.3897	568379.0973
NGFPP ($)	22113.7508	22991.6518
energy hub cost ($)	189546.415	195396.3145

Case 2: In this case, a review of the market clearing of regional-local MES has been provided considering ESS without their uncertainties for the local-level. As shown in Figure 14, the hourly scheduling of units has been compared with **Case 1**.

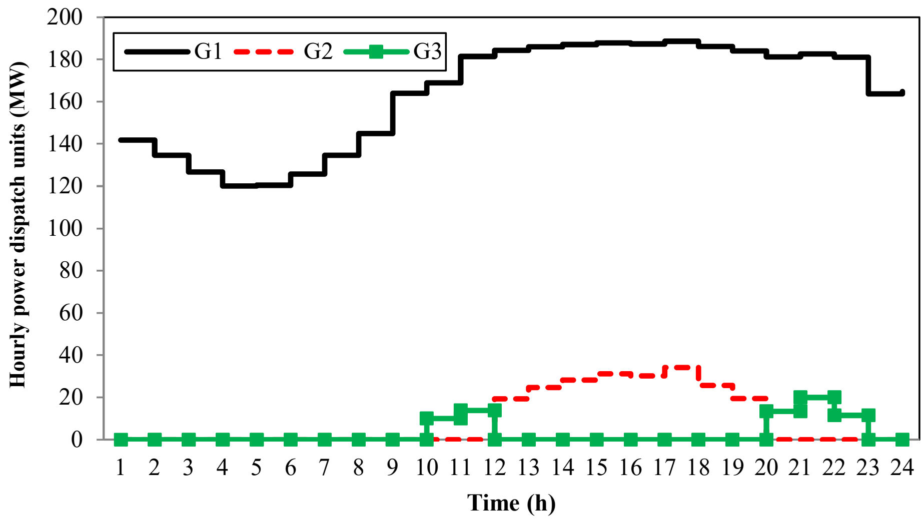

Figure 8: The hourly scheduling of units' commitment in **Case 1**

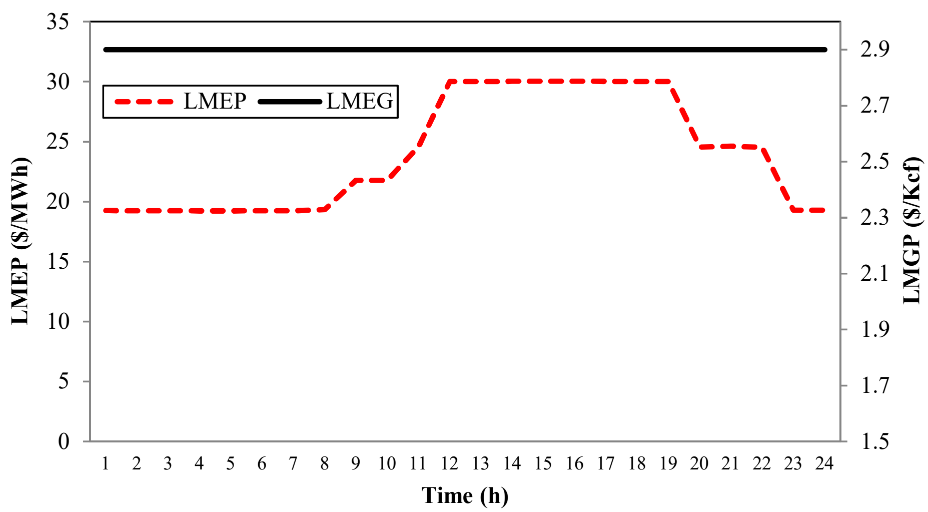

Figure 9: LMEPS obtained at the fifth bus and fifth node of the regional power system

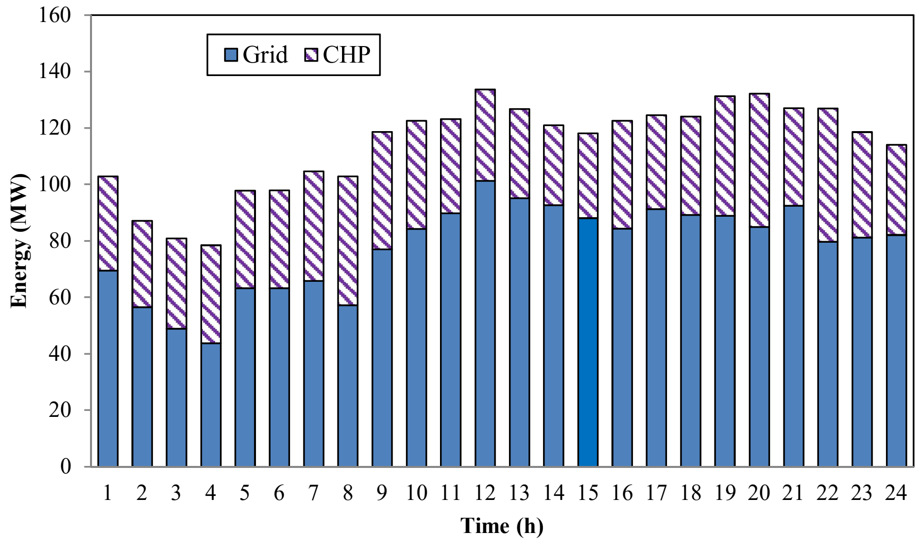

Figure 10: Hourly scheduling of energy hub to meet local-level electrical loads in **Case 1**

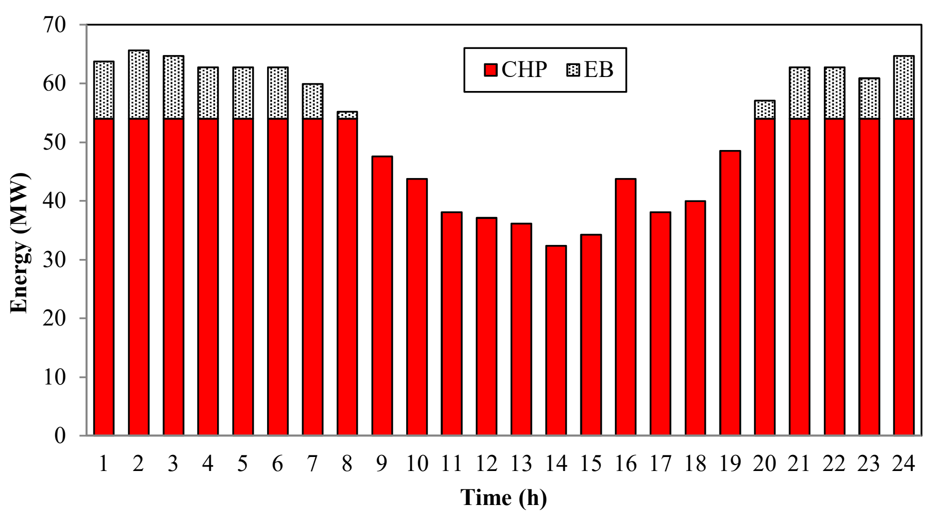

Figure 11: hourly scheduling of energy hub to meet local-level heating loads in **Case 1**

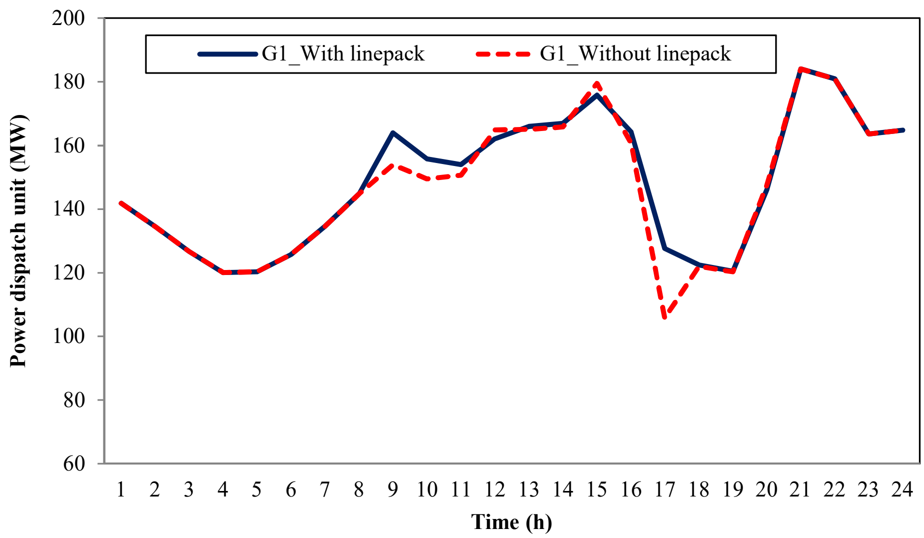

Figure 12: The impact of linepack system flexibility on G1 unit with an increase of 15% NG load

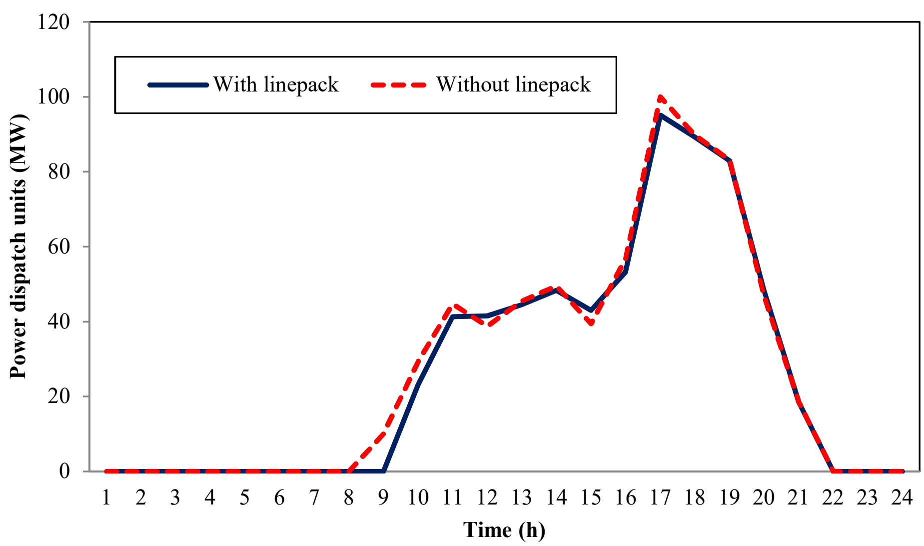

Figure 13: The impact of linepack system flexibility on G2 unit with an increase of 15% NG load

In this case, as demonstrated in Figure 14, the low-cost generation unit G1 is on for the entire period. Power generation of the expensive G2 unit has reduced to zero. The generation unit G3 also comes to operation from 15 to 20 hours. Compared to **Case 1**, the G1 unit's electrical energy dispatch has been increased in the early times due to the charging of local-level energy storage resources. In addition, due to the discharge of energy storage resources during peak hours, the number of commitments and the amount of G2 unit dispatch have been decreased significantly compared to the former case. In this case total operating costs, GFPPs and NGFPP are $535023.49, $535023.49 and $0, respectively. Also, the local level operating cost is $160057.74.

Figure 15 depicts the EHO scheduling for supplying local-level electricity. According to Figure 15, CHP has the top priority for supplying the local-level loads because of the low cost of NG. Likewise, the second priority is the supply of loads by the power system. Finally, electric storage performs the charging operation when the energy price is low and recharges when the price increases. According to the dashed line shown in Figure 15, the electricity purchased from the regional level has been decreased dramatically during the expensive hours of **Case 1**. Finally according to Figure 15, it can be seen that the local level electricity load supplied by the power grid, CHP, and ES are 60.43%, 32.24%, and 7.33% respectively.

Figure 16 shows how the EHO hourly scheduling is to supply local-level heating loads in **Case 2**. According to Figure 16, the scheduling for supplying the local-level heating loads is in such a way that the first priority of supplying the heating loads is done by CHP. EB is also scheduling to balance production and consumption in the time interval from 1 to 7 o'clock. Compared to **Case 1**, the production of heating energy is reduced by EB and the remaining demand is met by the heat storage. As expected, the HS stores heating energy at cheap times and recharges stored energy at expensive times. Finally according to Figure 16, it can be seen that the local level heating load supplied by the CHP, EB, and HS are 85.67%, 5.34%, and 8.99%, respectively.

Figure 17 is a comparison between LMEPs offered from the upstream market in **Case 1** and **Case 2**. As shown in Figure 17, the impact of local energy storage

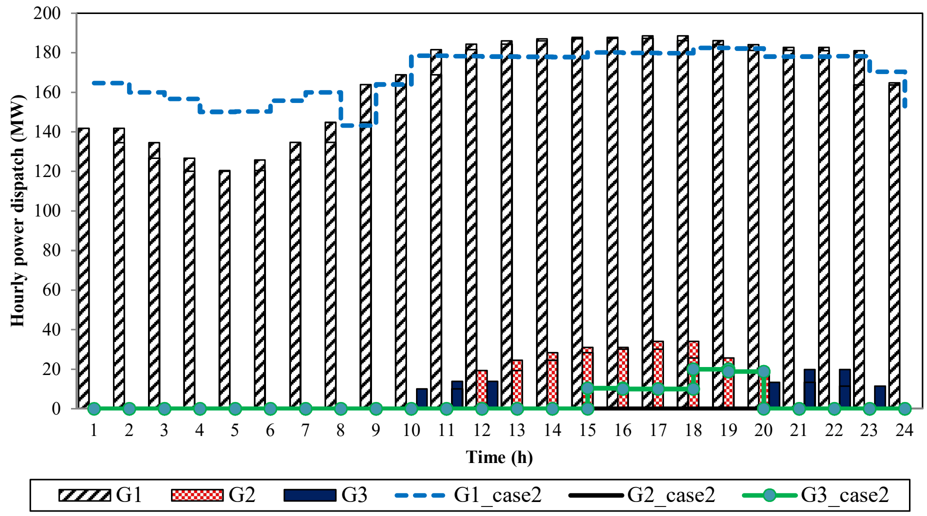

Figure 14: Hourly scheduling of production units' commitment in **Case 2**

resources on the LMP of the power system is remarkably obvious. Since energy storage resources store energy when the wholesale market prices are cheap and it injects the stored energy when the price is expensive, so it reduces the electric energy dispatch of the expensive unit of G2. Obviously, by lessening the dispatch of expensive units (i.e. from 12 to 20 o'clock), it reduces the LMEP offered from the wholesale market. The results confirm the reasoning presented.

Case 3: In this case a stochastic scheduling is performed to assess the market clearing at regional and local levels. The items that are considered for stochastic analysis in this case are as follows:

Case A1: Stochastic scheduling on market clearing at regional and local levels regardless of ESSs.

Case A2: Stochastic scheduling on market clearing at regional and local levels considering of ES.

Case A3: Stochastic scheduling on market clearing at regional and local levels considering of ES and HS.

In this case, the load and wind prediction error are estimated using a normal distribution function with a mean value equal to the predicted load and its standard

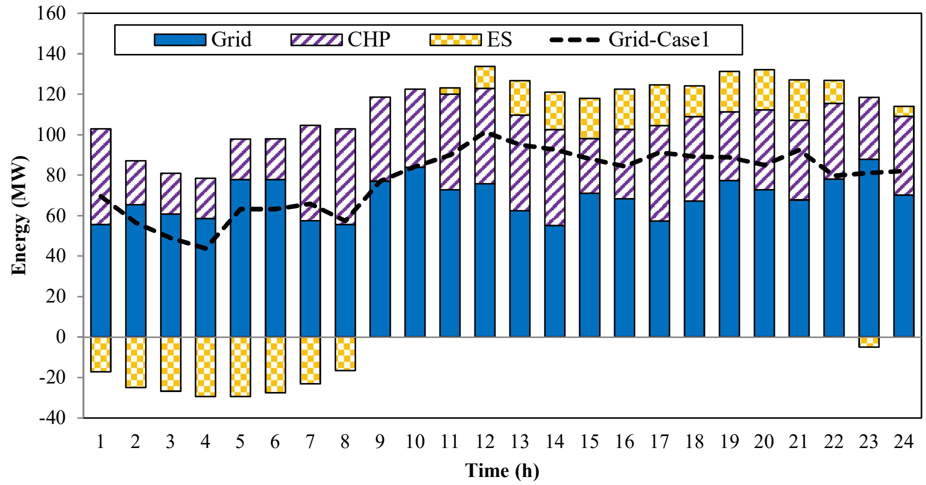

Figure 15: EHO hourly scheduling to supply local-level electrical loads in **Case 2**

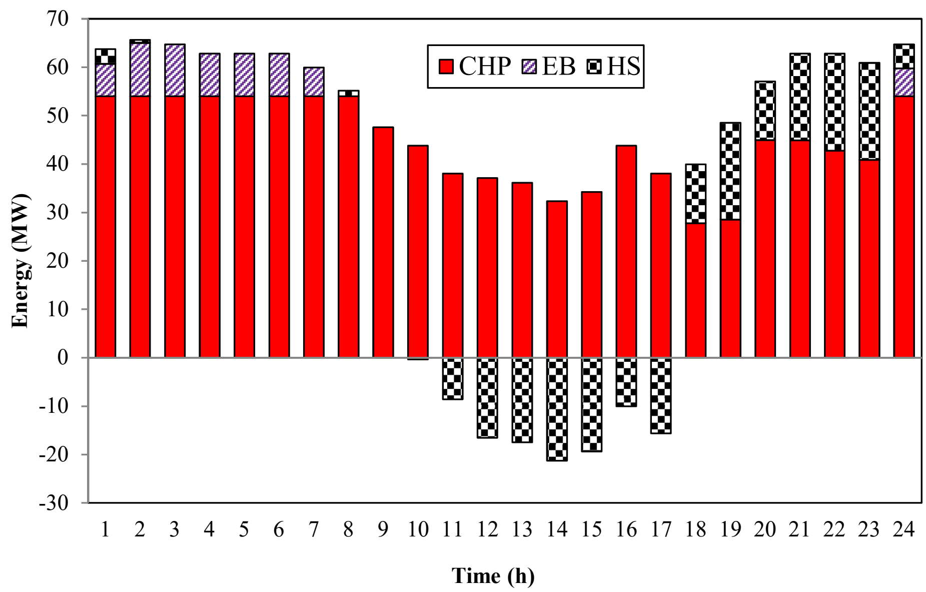

Figure 16: EHO hourly scheduling to meet local-level heating loads in **Case 2**

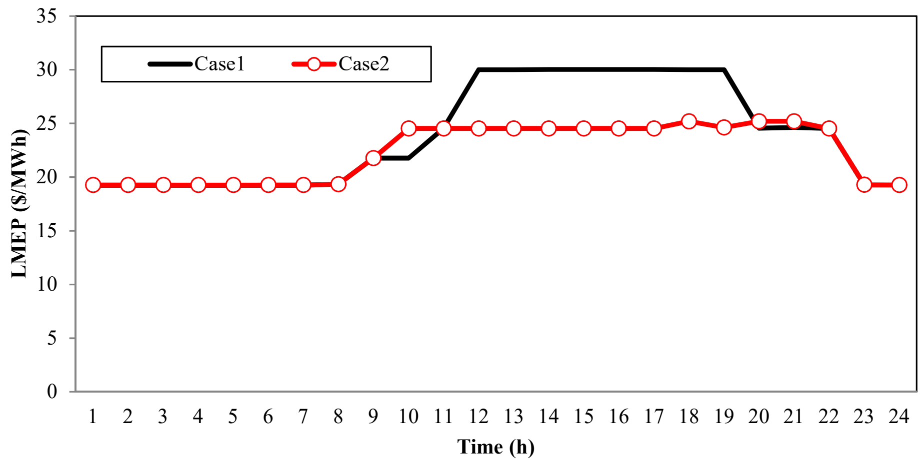

Figure 17: Comparison between the LMEPs obtained at the fifth bus of power system at the regional level

deviation is 5% and 10% of the mean value. A thousand-element scenario is generated by using Monte Carlo simulation and it is decreased to 10 scenarios by the scenario reduction method in GAMS/ SCENRED. In Tables 2, 3 and 4 are investigated the cost of different scenarios with related probabilities in **Case A1**, **Case A2** and **Case A3**, respectively. As is clear from the tables, in all cases the worst-case scenario for local and regional levels is the S8 scenario. It is also the best scenario for local and regional levels of the S10 scenario. Table 5 compares the allocation of operating costs in the three case studies under stochastic approach. The **Case A1** is regardless of ESS technologies, which has the highest operating cost. In **Case A2**, the addition of ES technology reduces the total cost of regional and local level system. Finally, in **Case 3**, the use of ES and HS technologies reduces operating costs at the local and regional level.

Table 2: Costs presented at different scenarios for **Case A1**

	S1	S2	S3	S4	S5
Scenarios	0.0293	0.0725	0.1819	0.0687	0.1095
Total cost	547910.6	548818	549439.9	548926.3	548254.5
GFPPs cost	535059.6	534620.7	536526.1	536278	536601.3
NGFPP cost	12851.04	13253.32	12913.83	12648.31	11617.15
energy hub cost	172724.6	172761.5	174686.5	174226.9	173570.6
	S6	S7	S8	S9	S10
Scenarios	0.0795	0.314	0.14	0.1539	0.1333
Total cost	545185.3	550242.6	552897.3	548398.2	544338.1
GFPPs cost	533568.1	536524.7	536400.9	535581.8	533511.7
NGFPP cost	11617.25	13717.95	16496.43	12816.39	10713.44
energy hub cost	169718.5	174772.9	177687.8	172759.7	169737.3

Table 3: Costs presented at different scenarios for **Case A2**

	S1	S2	S3	S4	S5
Scenarios	0.0293	0.0725	0.1819	0.0687	0.1095
Total cost	543905.6	543454.1	544445.4	544093.6	543469.7
GFPPs cost	533564.1	533167.6	535018.7	533948.1	534577.9
NGFPP cost	10341.47	10286.56	9426.664	10145.43	8891.817
Energy hub cost	166314.3	165729.4	167186.5	166593.5	165840.2
	S6	S7	S8	S9	S10
Scenarios	0.0795	0.314	0.14	0.1539	0.1333
Total cost	540788.2	545785.6	546884.5	543973.7	540013.7
GFPPs cost	531174.8	535078.1	534517.3	534219.8	531532.2
NGFPP cost	9613.447	10707.52	12367.22	9753.867	8481.506
Energy hub cost	163426.4	167823.2	168899.9	166606.2	162886.1

Table 4: Costs presented at different scenarios for **Case A3**

	S1	S2	S3	S4	S5
Scenarios	0.0293	0.0725	0.1819	0.0687	0.1095
Total cost ($)	539121.9	538087.2	540026.6	540079.9	538684.1
GFPPs cost ($)	533945.1	532872.2	535662.6	534583.9	534718.6
NGFPP cost ($)	4049.024	4088.65	3217.783	4368.28	2915.693
Energy hub cost ($)	162649.5	162054.1	163850.4	163363	162618.4
	S6	S7	S8	S9	S10
Scenarios	0.0795	0.314	0.14	0.1539	0.1333
Total cost ($)	536435.4	540640	542425.4	539510.7	535937.7
GFPPs cost ($)	531748.2	535167.7	535905	535125.2	531691.9
NGFPP cost ($)	3561.61	4329.808	5406.62	3259.108	3118.054
Energy hub cost ($)	160127.8	164373.8	165880.5	163306.5	159597.2

Table 5: Comparison of expected operating costs between **Case 1**, **Case 2** and **Case 3** under stochastic approach

	Case A1	**Case A2**	**Case A3**
Total cost ($)	548515.6	543656.2	539161.3
GFPPs cost ($)	535536.3	533758.4	534932.8
NGFPP cost ($)	128646.1	100016.5	43274.24
Energy hub cost ($)	173407.4	166165.5	161332.9

4. Conclusion

This paper presented a stochastic bi-level approach to evaluate the impact of energy storage resources on regional-local MES market-clearing with wind energy. In the upper-level problem, the objective of the EHO was to minimize the cost of purchasing electricity and NG using ESSs considering wind power generation. In the lower level problem, the CSO-managed integrated electricity and NG markets were implemented to minimize the cost of generating units and NG producers. To solve this bi-level problem, a two-step iterative algorithm was proposed to minimize the costs of both levels of the problem. In addition, a scenario-based stochastic approach was applied to handle the uncertainties of different local loads. Additionally, a NG system model equipped with line pack technology was considered to increase flexibility and reduce the cost of operating the regional level system. The results showed that in the presence of the multi-carrier energy storage, the daily operation cost at the local and regional levels was decreased by 7.01% and 1.7%, respectively.

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