Strategic participation of integrated thermal and electrical energy service provider in natural gas and wholesale electricity markets

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***Abstract*—The accelerating interest in energy system models has influenced numerous revolutionized alterations in the wholesale gas and electricity market. This study proposes a novel bi-level multi-follower optimization framework for the strategic behavior observation of an integrated (thermal and electrical) energy service provider (IESP) as a price-maker in the wholesale electricity market (WEM) and natural gas market (NGM). At the upper level, the IESP submits offers/bids in WEM and NGM to procure electricity/gas to the customers. To this end, the IESP endeavors to minimize operational costs and influence the market-clearing price (MCP) by deploying demand-side flexibilities, i.e., elastic electrical and thermal loads. At the lower level, the wholesale electricity market operator (WEMO) and natural gas market operator (NGMO) receive offers/bids from all market participants and clear the market with the goal of maximizing social welfare. The IESP is modelled via the IEEE-33 bus active distribution system (ADS) and an 8-node district heating system (DHS), while the WEM and NGMs are embodied by a 6-bus transmission network (TN) and a 21-node natural gas network (NGN), respectively. Karush–Kuhn–Tucker (KKT) conditions are introduced to transform the multi-follower bi-level optimization problem into a single-level problem, while the inherent nonlinearities of the problem are linearized using the theory of strong duality. Moreover, the intrinsic intermittencies of the renewable energy sources (RES) is dealt with by the risk-averse information gap decision theory (IGDT). The results confirm that flexible electrical and thermal demands can diminish the market-clearing price by as much as 4.1%.**

***Index Terms*—Integrated energy service provider; Natural gas market; Electricity market; District heating systems; Flexible demand; Price-maker.**

NOMENCLATURE

Indices

i, t, k, r	Indices of ADS bus's, time, DGs, wind turbine
l, ϑ, e, q	Indices of pipeline, node, demand and source in DHS.
pv, u, s, R	Indices of PVA, ILs, shiftable loads, feasible operation region in CHP units
$n, w, \lg, c$	Indices of NGN nods, NGN producer, active pipeline, non-active pipeline
e, d, dg	Indices of GS, ADS loads, NGN loads
g, b, b'	Indices of Genco, TN bus's
A_n^m	Set of m equipment's located at ADS and TN bus's or NGN nodes n
Tr	Set of bus's connected to each other in the TN.
CHP, NGU	Set of CHP and non-gas fired DGs.

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Parameters

$C_k^{DG}, C_r^{Wind}, C_{pv}^{PV}$	Operating costs of DGs, wind power, pv ($/MWh).
C_u^{IL}, C_s^{DR}	IL, DRP costs ($/MWh).
$\underline{P_k^{DG}}, \overline{P_k^{DG}}$	Minimum/Maximum output power of DGs (MW).
P^R, ϕ^R	Rth extreme point of the feasible operating region (MW).
γ_p, γ_H	Power and heat generations of the CHP (%).
C_k^{SU}, C_k^{SD}	Startup/shutdown cost of NGFDU ($/MWh).
C_k^{GSU}, C_k^{GSD}	Amount of fuel used to startup and shutdown of CHP units (Kcf)
R_k^{UP}/R_k^{DN}	Ramp up/down of DGs (MW).
T_k^U, T_k^D	Min on, off time of DGs (h).
$\overline{P_{r,t}^{Wind}}, \overline{P_{pv,t}^{PV}}$	Maximum output power of wind and PV (MW).
$\rho_{LS}, \Gamma_{LS}, P_{u,t}^{IL,\max}$	Load control factor, maximum load shifting, Maximum of interrupted load (MW).
Z_{ij}^{DS}, R_{ij}^{DS}	Impedance, resistance of ADS feeders (ohm).
$I_{ij}^{DS\_\max}$	Maximum current of ADS feeders (A).
$\underline{V_i^{DS}}, \overline{V_i^{DS}}$	Maximum, minimum of ADS bas's (KV).
$\underline{T_l^{DHS}}, \overline{T_l^{DHS}}$	Minimum/Maximum pipeline temperature in DHS (°C)
$\underline{T_\vartheta^{DHS}}, \overline{T_\vartheta^{DHS}}$	Minimum/Maximum nodal temperature in DHS (°C)
$T_{\vartheta,e}^{\min}/T_{\vartheta,e}^{\max}$	Minimum/Maximum indoor temperature of AH. (°C)
λ_l, L_l	Thermal conductivity rate and length of DHS pipeline (m)
C_p, R	Thermal capacity of water, thermal resistance of households (MWh/kg.°C), (°C/MWh)
$ms_{t,l}, mr_{t,l}$	Water mass flow of supply/return DHS pipeline (kg/h)
$m_{t,\vartheta,e}^{de}, m_{t,\vartheta,q}^{sr}$	Water mass flow of demand/source at DHS nodes (kg/h)

$n^{ho}_{\vartheta,e}, Cair_{\vartheta,e}$	Number of households and their average thermal capacity at DHS nodes (MWh/°C)
$\underline{P_t^{IESP}}, \overline{P_t^{IESP}}$	Maximum/minimum power traded with the EWM (MW).
$C^{Max}_{b,b'}$	Maximum power flow capacity in TN lines (MW).
	Variables
$P_t^{IESP}, G_{k,t}^{GFU}$	Electricity and NG are traded by the IESP with the EWM and NGM.
$P^{Wind}_{r,t}, P^{PV}_{pv,t}$	Output power of wind turbine and PV (MW).
$P^{IL}_{u,t}, P^{DR}_{s,t}$	Amount of IL and shifting load (MW).
$SU_{k,t}, SD_{k,t}$	Amount of startup and shutdown calculated for NGU ($/MWh).
$GSU_{k,t}, GSD_{k,t}$	Amount of fuel gas consumed by the CHP unit to Startup/shutdown (Kcf).
$P^{DG}_{k,t}, H^{DG}_{k,t}$	Power and heating output DGs and CHP (MW).
$P^{flow}_{ij,t}, P^{loss}_{ij,t}$	Power flow and power loss in the ADS feeders (MW).
$I^{DS}_{ij,t}, V^{DS}_{i,t}$	ADS feeder current (A) and ADS bus's voltage (KV).
$T^{ps,out}_{t.l}/T^{pr,out}_{t,l}$	Temperature at the end of supply /return pipes in DHS (°C)
$T^{ps,in}_{t.l}/T^{pr,in}_{t,l}$	Temperature at the beginning of supply /return pipes in DHS (°C)
$T^{ms}_{t,\vartheta}, T^{mr}_{t,\vartheta}$	Nodal temperature of supply/return pipes in DHS (°C)
$T^{in}_{t,\vartheta,e}, H^{loss}_{t,l}$	Indoor temperature in AH and thermal energy loss in piplines. (MWh)
$H^{sor}_{t,\vartheta,q}, H^{ho}_{t,\vartheta,e}$	Thermal energy delivered by source and absorbed by household. (MWh)
$P^G_{g,t}$	Power generated by Gencos (MW).
$\delta_{b,t}$	Voltage bus angle of TN (Rad)
$q_{w,t}$	Gas output of the NG wells (KCf)
$q_{\lg,t}, q_{c,t}$	Gas flow in active, passive pipelines (KCf)
$q^{in}_{e,t}, q^{out}_{e,t}$	In rate, out rate of the GSS (KCf)
$GS_{e,t}$	Storage capacity of the GSS (KCf)
$Q^{CHP}_{k,t}$	Amount of gas consumed by CHP units
α^R_t	Combination coefficient of corner point
	Binary Variables
$I_{k,t}$	Commitment state of DGs.
$y_{k,t}, z_{k,t}$	Startup and shutdown state of DGs.
	Dual variables
μ, v, ζ	Inequality dual variables in the TN.
λ	Equality dual variables in the TN.
β	Inequality dual variables in the NGN.
γ, ρ	Equality dual variables in the NGN.
X_1, X_2	Linearized cost of IESP participation in NGM/WEM ($)

I. Introduction

A. Motivation

In the field of advanced power systems, energy service providers transfer bids from consumers to the wholesale market. Afterward, the independent system operator (ISO) clears the market according to the received offers/bids from producers/consumers, clarifying the ultimate market clearing price (MCP) and the production/consumption share of each player. In other words, energy service providers are intermediary entities between consumers and the wholesale market [1]. In previous studies, one type of energy (i.e., Electricity) has been prioritized [2]– [3]. However, with advances in coupling energy technology, e.g., combined heat and power units (CHP), combined cooling heating and power units (CCHP) and electrical boilers (EB), the energy infrastructures such as thermal, natural gas and electrical systems have become inextricably interconnected. Additionally, the existence of numerous multi-energy systems and new commercial conformations have influenced the decision procedure of the integrated energy systems. In this regard, the researchers are exploring new means to model the behavior of the current multi-energy systems, which can participate in energy markets as a price-maker player that is capable of influencing MCP [4]. In fact, in this study, we seek to investigate a new entity that is aptly named as the integrated energy service provider (IESP). This new market player is obliged to participate in the wholesale electricity market (WEM) and natural gas market (NGM) to supply the integrated electrical and thermal demand.

B. Literature review

There are many noteworthy studies on the integrated power, natural gas and district heating systems (DHS), each of which has focused on a different facet, such as operation [5], flexibility improvement [6], optimal energy management [7] or addressing the uncertainties [8]. In [9], an optimal participation strategy for a large-scale multi-energy system was presented to take part in real-time electricity market, day-head electricity market, local electricity market, and the natural gas market, considering uncertainties. Furthermore, investigating the strategic behavior of the energy players in different energy markets has recently been a trending topic. In some studies, these players have been represented as strategic production units, such as the strategic behavior of the conventional units in the pool market [10], wind farms in the wholesale market [11], or the hydro unit in the day-ahead wholesale market [12]. Additionally, the strategic behavior of the energy players have been investigated from various perspectives, such as the impact of energy storage on day-ahead and reserve markets [13], aggregated electric vehicles in the day-ahead wholesale market [14], along with virtual power plants in day-ahead and balancing markets [15]. The majority of these studies are modelled as a bi-level or multi-level problem, wherein the strategic players are integrated into the upper level, while energy markets form the lower-level followers.

Another subject that has gained attention is the strategic behavior of the distribution companies (Disco) in various energy markets. In [16], strategic behavior of a Disco on transactions with WEM was evaluated under risk measures. Similarly, the authors in [17] did not only study the strategic behavior of Disco in WEM, but they also included the reserve market. To study the strategic behavior of a multi-energy system in the WEM, a bi-level approach was presented in [18], which minimized the total cost. The multi-energy system was considered as the upper level, while WEM problem defined the lower level of the bi-level problem. Authors in [19] have proposed a robust bi-level approach for the participation of an integrated energy service provider in the WEM as a price-maker player. The literature [20] investigated the Disco's participation in day-ahead and real-time markets considering proper risk measures. Ref [21] inspected a bi-level strategic scheduling framework for Disco wherein WEMO and the microgrids supplied by Disco were modelled as lower-level followers. Generally, it is observed that most of the earlier studies have been centered on one type of energy, i.e., electricity. However, with rising modern co-generation and tri-generation systems, such as CHPs and CCHPs, the regulatory and administrative associations are faced with new challenges. The most perplexing one has been the strategic behavior of the energy service providers in various energy markets, e.g., electricity and natural gas. In this regard, ref [22] proposed the strategic stochastic bidding of a multi-energy micro grid in day-ahead and real-time markets. Furthermore, a mathematical program with equilibrium constraints (MPEC) has been scrutinized in [23] for the strategic behavior of a multi-energy system in electricity and thermal energy markets, where the multi-energy system operator has been designated as the leader while appointing thermal and electrical market operators as followers. Moreover, the impact of uncertain production units such as wind turbines (WT) and photovoltaic arrays (PVA) on transactional behaviors of the multi-energy systems has been discussed in [24]. Likewise, [25] evaluated multi-energy service providers as intermediary bodies that connect aggregated distributed generators to WEM. A stochastic bi-level decision framework was introduced in [26] to assess local multi-energy service providers in integrated NGM and WEM. Additionally, the strategic behavior of the multi-energy system in trades with local energy market and other multi-energy systems was evaluated in [27]. Eventually, the authors in [28] have adressed the optimal energy procurement problem of a multi-energy system, considering pool market, available forward contracts and the strategic responses of rival multi-energy systems.

C. Contributions

Apparently, the literature has not yet explored the strategic behavior of the IESP in transactions with natural gas and wholesale markets as a price-maker player using the IGDT approach. To take a more detailed look at the gaps of these studies, their main characteristics is included in Table I. Accordingly, the following points can be made:

- The studies [5]–[9], [22], [24], [25], [27], [28], were focused on strategic behavior of the executive and regulatory branches in the integrated energy systems as price-taker participants. Nonetheless, a price-taker player has no say over MCP and they have to perform energy procurement under the price that is declared by WEMO and NGMO.
- In refs [10]–[17], [20], [21], the authors have only investigated one type of energy, i.e., electricity. Nevertheless, the appearance of co-generation and tri-generation technologies has led to fundamental infrastructural modifications that resulted in inextricably interconnected thermal, electrical and natural gas systems.
- In studies [18], [19], [22]–[28], the authors have ignored the network (thermal electrical and natural gas networks) models, constraints and load flow equations as a simplifying assumption that makes the results non-viable in real-world circumstances.

To tackle these issues, this study puts forward a distinctive bi-level single-leader and multi-follower framework to evaluate the strategic behavior of the IESP in transactions with NGM and WEM as a price-maker player that can influence MCP. At the upper level, the IESP operates an integrated district heating system (DHS) and an active distribution system (ADS). On account of the fact that DHSs do not cover large areas, and they are fed mainly by the thermal output of the CHP units, it is not a farfetched assumption that they would operate under the command of a single operator, i.e., IESP. The IESP tries to incorporate the flexibilities of the thermal and electrical demands to lower MCP and after receiving requirements of the thermal/electrical loads, and the production capabilities, submits the offers/bids in NGM and WEM markets. At the lower level, WEMO and NGMO operate as individual followers that respectively clear the NGM and WEM to maximize community welfare. Eventually, the risk-averse IGDT approach is deployed to deal with the inherent uncertainties of RES. Overall, the principal contributions of this study can be outlined as follows:

i A bi-level multi-follower optimization framework based on risk-averse IGDT is proposed to evaluate the strategic behavior of the IESP in WEM and NGM as a price-maker player. To the best of authors' knowledge, this type of model has not been investigated in any of the previous publications.

ii The impact of thermal/electrical flexibilities on MCP of WEM/NGM and strategic behavior of the IESP is examined.

iii The mutual influence of each player/market on MCP and decision-making process of other players/markets in integrated thermal, electrical and natural gas systems is scrutinized.

The remainder of this paper is organized as follows: The problem is elaborated in section II, while section III provides the IGDT-based bi-level formulation of the integrated energy service provider. Section IV presents the case studies and results. Finally, conclusions are listed in section V.

II. Problem description

In this study, the IESP is considered as a price-maker participant in NGM and WEM. Based on the illustrative flowchart in Fig. 1, at the first stage, the IESP receives basic information that consists of number of aggregated households (AHs) in DHS, thermal/electrical demand requirements, production constraints of gas-fired/non-gas-fired units (NGU), RES and ADS/DHS constraints. At the next step, after

TABLE I: Comparative evaluations between this study and previous works

Ref	Strategic player	Strategic behavior		Distribution network constraints		Bi-level model	Wholesale market constraints		Uncertainty
		Price-taker	Price-maker	Electrical	Thermal		Electrical	Natural gas	
[9]	Multi-energy system	✓	×	×	×	×	✓	×	SP-RO
[10]	Gencos	×	✓	×	×	✓	✓	×	×
[11]	Wind turbine	×	✓	×	×	✓	✓	×	SP
[12]	Hydro units	×	✓	×	×	✓	✓	×	SP
[13]	Storage system	×	✓	×	×	✓	✓	×	Two-stage SP
[14]	Vehicle aggregator	×	✓	×	×	✓	✓	×	SP
[15]	Virtual power plant	×	✓	×	×	✓	✓	×	IGDT
[16]	Disco	×	✓	×	×	✓	✓	×	CVaR
[17]	Disco	×	✓	✓	×	✓	✓	×	SP
[18]	Multi-energy system	×	✓	×	×	✓	✓	×	SP-RO
[19]	IESP	×	✓	✓	×	✓	✓	×	RO
[20]	Disco	×	✓	✓	×	✓	✓	×	Two-stage SP
[21]	Disco	×	✓	✓	×	✓	✓	×	Risk-SP
[22]	Microgrid	✓	×	×	×	×	×	×	SP
[23]	Multi-energy system	×	✓	✓	✓	✓	×	×	×
[24]	Multi-energy players	✓	×	×	×	✓	×	×	SP
[25]	Multi-energy service providers	✓	×	×	×	✓	×	×	SP
[26]	Multi-energy system	×	✓	×	×	✓	✓	✓	SP
[27]	Multi-energy system	✓	×	×	×	✓	×	×	×
[28]	Multi-energy system	✓	×	×	×	✓	×	×	SP
This paper	**IESP**	✖	✔	✔	✔	✔	✔	✔	**IGDT**

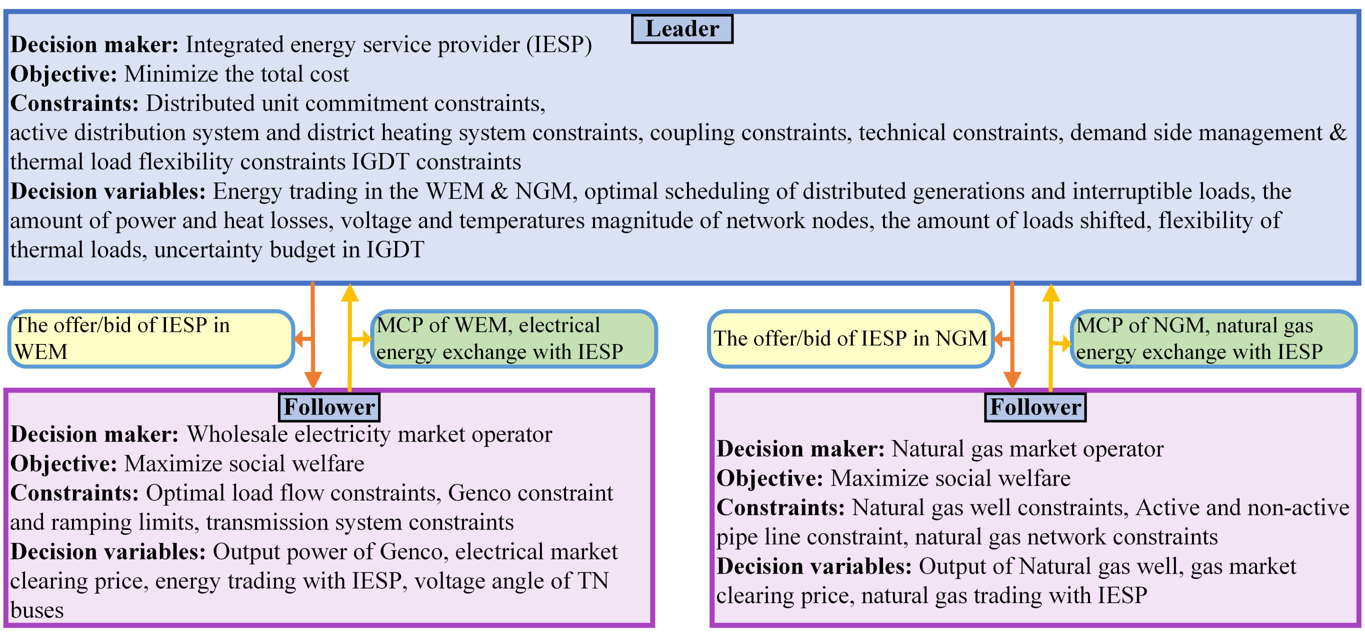

Fig. 1: Problem description in flowchart representation.

scheduling the commitment status of the units in DHS and ADS, the IESP submits offers/bids to participate in NGM and WEM. Subsequently, the NGMO and WEMO individually receive offers/bids from other market players, such as gas wells, Generation companies (Genco) and other gas/electricity consumers. Then NGMO and WEMO clear their own separate markets to clarify the MCP and generation/consumption share of each participant.

Moreover, the MCP processing is executed with the objective of maximizing social welfare subjected to operational constraints of the natural gas network (NGN), transmission network (TN), Gencos and gas wells. It should be reiterated that the NGMO and WEMO function individually with their own independent objective. When the ultimate gas/electricity MCP is announced, the IESP reschedules all its units and responsive thermal/electrical loads, then resubmits offers/bids in NGM and WEM. Afterward, market clearing process is repeated by NGMO and WEMO. This iterative procedure is carried out until the algorithm converges to an equilibrium point for all the players, where the changes in offers/bids of two consecutive iterations are lower than a predefined epsilon value. In this study, the equilibrium point is achieved by replacing the bi-level or multi-level optimization problems with a single-level problem using KKT conditions linearized by the theory of strong duality. In this approach, the decisions of each player (NGMO, WEMO and IESP) have a mutual impact on that of the others. For instance, the thermal or electrical power dispatch in integrated DHS and ADS can influence the MCP and units scheduling in NGM and WEM. Similarly, the decisions of the IESP are bound to behaviors of the NGMO and WEMO.

III. Formulation

A. Integrated energy service provider (Leader)

1) Objective function: The objective function of the IESP is defined in Eq. (1), which minimizes the operational costs of integrated DHS and ADS. As illustrated, the objective function is comprised of seven terms, including the cost of energy procured from WEM, WT generation cost, cost of natural gas from NGM, the production and start-up/shutdown costs of distributed generation units (DGs), PVA generation cost, interruptible loads (IL), and demand response program (DRP) cost, respectively.

$$\min \sum_t \left\{ \begin{array}{l} \lambda_{b,t} P_t^{IESP} + \sum\limits_r C_r^{Wind} P_{r,t}^{Wind} + \sum\limits_k \gamma_{n,t} G_{k,t}^{GFU} \\ + \sum\limits_{k \in NGU} (C_k^{DG} P_{k,t}^{DG} + SU_{k,t} + SD_{k,t}) \\ + \sum\limits_{pv} C_{pv}^{PV} P_{pv,t}^{PV} + \sum\limits_u C_u^{IL} P_{u,t}^{IL} + \sum\limits_s C_s^{DR} P_{s,t}^{DR} \end{array} \right\} \tag{1}$$

2) Unit commitment of DGs: Equation Eq. (2) represents the commitment status of the DGs in ADS. Eqs. (3)-(6) restrict the thermal/electrical power generation of the CHP units to a feasible operation region (FOR). The natural gas consumption of the CHP units is defined by Eq. (7).The start-up/shutdown costs of non-gas-fired units (NGU) are imposed by Eqs. (8)-(9); likewise, Eqs. (10)-(11) define the gas consumption cost for start-up/shutdown acts of CHP units. The ramp up/down constraints of the DGs are declared by Eqs. (12)-(13), while Eqs. (14)-(23) impose the minimum on/off time limitations of DGs [29]. Finally, wind and solar productions are in Eqs. (24)-(25).

$$\underline{P_k^{DG}} I_{k,t} \le P_{k,t}^{DG} \le \overline{P_k^{DG}} I_{k,t} \forall k \in \{NGU\}, \forall t \tag{2}$$

$$P_{k,t}^{DG} = \sum_{R=1} \alpha_t^R P^R \forall k \in CHP, \forall t \tag{3}$$

$$H_{k,t}^{DG} = \sum_{R=1} \alpha_t^R \phi^R \forall k \in CHP, \forall t \tag{4}$$

$$\sum_{R=1} \alpha_t^R = I_{k,t} \forall k \in CHP, \forall t \tag{5}$$

$$0 \le \alpha_t^R \le 1 \forall R, \forall t \tag{6}$$

$$Q_{k,t}^{CHP} = \gamma_p P_{k,t}^{DG} + \gamma_H H_{k,t}^{DG} \forall k \in CHP, \forall t \tag{7}$$

$$SU_{k,t} \ge C_k^{SU} y_{k,t} \forall k \in NGU, \forall t \tag{8}$$

$$SD_{k,t} \ge C_k^{SD} z_{k,t} \forall k \in NGU, \forall t \tag{9}$$

$$GSU_{k,t} \ge C_k^{GSU} y_{k,t} \forall k \in \{CHP\}, \forall t \tag{10}$$

$$GSD_{k,t} \ge C_k^{GSD} z_{k,t} \forall k \in \{CHP\}, \forall t \tag{11}$$

$$P_{k,t}^{DG} - P_{k,t-1}^{DG} \le (1 - y_{k,t}) R_k^{UP} + y_{k,t} \underline{P_k^{DG}} \forall k, \forall t \tag{12}$$

$$P_{k,t-1}^{DG} - P_{k,t}^{DG} \le (1 - z_{k,t}) R_k^{UP} + z_{k,t} \underline{P_k^{DG}} \forall k, \forall t \tag{13}$$

$$T_k^{Ue} = \min \left\{ T, T_k^{U0} \right\} \tag{14}$$

$$T_k^{De} = \min \left\{ T, T_k^{D0} \right\} \tag{15}$$

$$\sum_{t=1}^{T_k^{Ue}} I_{k,t} = T_k^{Ue} \forall k \tag{16}$$

$$\begin{array}{l} \sum\limits_{t=r}^{t+T_k^{Ue}-1} I_{k,r} \ge T_k^U y_{k,t} \\ \forall k, \forall t = \left[T_k^{Ue} + 1, ..., T - T_k^U + 1 \right] \end{array} \tag{17}$$

$$\sum_{t=r}^{T} (I_{k,r} - y_{k,t}) \ge 0 \forall k, \forall t = \left[T - T_k^U + 2, ..., T \right] \tag{18}$$

$$\sum_{t=1}^{T_k^{De}} I_{k,t} = 0 \forall k \tag{19}$$

$$\begin{array}{l} \sum\limits_{t=r}^{t+T_k^{D}-1} (1 - I_{k,r}) \ge T_k^D z_{k,t} \\ \forall k, \forall t = \left[T_k^{De} + 1, ..., T - T_k^D + 1 \right] \end{array} \tag{20}$$

$$\begin{array}{l} \sum\limits_{t=r}^{T} (1 - I_{k,r} - z_{k,t}) \ge 0 \\ \forall k, \forall t = \left[T - T_k^D + 2, ..., T \right] \end{array} \tag{21}$$

$$y_{k,t} - z_{k,t} = I_{k,t-1} - I_{k,t} \forall k, \forall t \tag{22}$$

$$y_{k,t} + z_{k,t} \le 1 \forall k, \forall t \tag{23}$$

$$0 \le P_{r,t}^{Wind} \le \overline{P_{r,t}^{Wind}} \forall r, \forall t \tag{24}$$

$$0 \le P_{pv,t}^{PV} \le \overline{P_{pv,t}^{PV}} \forall pv, \forall t \tag{25}$$

3) Demand response program and interruptible loads: Equations Eqs. (26)-(28) model the DRP, while ILs are defined by Eq. (29).

$$P_{s,t}^{DR} = (1 - \phi_{s,t}) P_{s,t}^{DSRL} \forall s, \forall t \tag{26}$$

$$0 \le \phi_{s,t} \le \Gamma_{LS} \forall s, \forall t \tag{27}$$

$$\sum_t P_{s,t}^{DSRL} \phi_{s,t} = \rho_{LS} \sum_t P_{s,t}^{DSRL} \forall e \tag{28}$$

$$0 \le P_{u,t}^{IL} \le P_{u,t}^{IL,\max} \forall u, \forall t \tag{29}$$

4) Active distribution system: In this study, to satisfy power the flow constraints of the ADS, a linearized framework is deployed, which is adopted from [21]. The power flow of lines is imposed by Eq. (30), while Eqs. (31)-(32) define the power loss and current flow in feeders of the ADS. Current limitations of the feeders and voltage limitations of the nodes are enforced by Eqs. (33)-(34), respectively. The nodal energy equilibrium is ensured by Eqs. (35)-(36) in the slack bus and other buses. Eq. (37) shows the amount of gas consumed by the CHP unit.

$$P_{ij,t}^{flow} = \frac{R_{ij}^{DS}}{(Z_{ij}^{DS})^2}(V_{i,t}^{DS\_sqr} - V_{j,t}^{DS\_sqr})\forall ij, \forall t \tag{30}$$

$$P_{ij,t}^{Loss} = R_{ij}^{DS} I_{ij}^{DS\_sqr} \forall ij, \forall t \tag{31}$$

$$I_{ij,t}^{DS} = \frac{V_{i,t}^{DS} - V_{j,t}^{DS}}{Z_{ij}^{DS}} \forall ij, \forall t \tag{32}$$

$$-I_{ij}^{DS\_\max} \leq I_{ij,t}^{DS} \leq I_{ij}^{DS\_\max} \forall ij, \forall t \tag{33}$$

$$\underline{V_i^{DS}} \leq V_{i,t}^{DS} \leq \overline{V_i^{DS}} \forall i, \forall t \tag{34}$$

$$\begin{aligned} &P_t^{IESP} + \sum_{r \in A_i^r} P_{r,t}^{Wind} + \sum_{pv \in A_i^p v} P_{pv,t}^{PV} + \sum_{k \in A_i^k} P_{k,t}^{DG} \\ &+ \sum_{s \in A_i^s} P_{s,t}^{DR} + \sum_{u \in A_i^u} P_{u,t}^{IL} = \sum_{s \in A_i^s} P_{s,t}^{DSRL} + \sum_{d \in A_i^d} P_{d,t}^{DSNRL} \\ &+ \sum_{s \in A_i^e b} +0.5(\sum_{j \in DS} P_{ij,t}^{Loss} + \sum_{j \in DS} P_{ij,t}^{flow}) \forall i = 1, \forall t \end{aligned} \tag{35}$$

$$\begin{aligned} &\sum_{r \in A_i^r} P_{r,t}^{Wind} + \sum_{pv \in A_i^p v} P_{pv,t}^{PV} + \sum_{k \in A_i^k} P_{k,t}^{DG} + \sum_{s \in A_i^s} P_{s,t}^{DR} \\ &+ \sum_{u \in A_i^u} P_{u,t}^{IL} = \sum_{s \in A_i^s} P_{s,t}^{DSRL} + \sum_{d \in A_i^d} P_{d,t}^{DSNRL} \\ &+ \sum_{s \in A_i^e b} P_{eb,t}^{EB} + 0.5(\sum_{j \in DS} P_{ij,t}^{Loss} + \sum_{j \in DS} P_{ij,t}^{flow}) \forall i \neq 1, \forall t \end{aligned} \tag{36}$$

$$G_{k,t}^{GFU} = Q_{k,t}^{CHP} + GSU_{k,t} + GSD_{k,t} \forall k \in \{CHP\}, \forall t \tag{37}$$

5) District heating system: In this study, the hot water pipeline network method is adopted to model DHS. The nodal temperature of the DHS is obtained as the equilibrium temperature of all pipelines that are united in a node, which is established in Eqs. (38)-(39). The water temperature of pipeline exiting a node is equal to the equilibrium temperature of that node as imposed by Eq. (40). Eq. (41) defines the nodal thermal demand. Due to the thermal energy loss, the pipelines' temperature drops at the end of the line as shown by Eq. (42). The amount of energy loss is calculated via Eq. (43). In this study, EB and CHP units are incorporated as thermal energy sources and Eq. (44) defines the amount of energy they deliver to DHS. The thermal equilibrium of the DHS is ensured by Eq. (45), while Eq. (46) defines the temperature of the AH. Eventually, the upper and lower temperature bounds of AH and DHS are enforced by Eqs. (47)-(48). Moreover, Eq. (50) defines the thermal energy production of the EBs, while Eq. (51) restricts their electrical consumption. Eventually, total thermal energy productions is established through Eq. (52).

$$\sum_{l \in s_\vartheta^-} (T_{t,l}^{ps,out}.ms_{t,l}) = T_{t,\vartheta}^{ms} \sum_{l \in s_\vartheta^-} ms_l \forall t, \forall \vartheta \tag{38}$$

$$\sum_{l \in s_\vartheta^+} (T_{t,l}^{pr,out}.mr_{t,l}) = T_{t,\vartheta}^{mr} \sum_{l \in s_\vartheta^+} mr_l \forall t, \forall \vartheta \tag{39}$$

$$\begin{cases} T_{t,\vartheta}^{ps,in} = T_{t,l}^{ms}, & l \in S_\vartheta^+ \\ T_{t,\vartheta}^{pr,in} = T_{t,l}^{mr}, & l \in S_\vartheta^- \end{cases} \forall t, \forall l \tag{40}$$

$$H_{t,\vartheta,e} = C_p m_{t,\vartheta,e}^{de}(T_{t,\vartheta,e}^{ms} - T_{t,\vartheta,e}^{mr}) \forall t, \forall \vartheta, \forall e \tag{41}$$

$$\begin{cases} T_{t.l}^{ps,out} = (T_{t,l}^{ps,in} - T_t^{out}) e^{\frac{-\lambda_l L_l}{C_p ms_l}} + T_t^{out} \\ T_{t,l}^{pr,out} = (T_{t,l}^{pr,in} - T_t^{out}) e^{\frac{-\lambda_l L_l}{C_p mr_l}} + T_t^{out} \end{cases} \forall t, \forall l \tag{42}$$

$$H_{t,l}^{loss} = C_p m_{t,l}(T_{t,l}^{in} - T_{t,l}^{out}) \forall t, \forall l \tag{43}$$

$$H_{t,\vartheta,q}^{sor} = C_p m_{t,\vartheta,q}^{sr}(T_{t,\vartheta,q}^{in} - T_{t,\vartheta,q}^{out}) \forall t, \forall \vartheta, \forall q_{\in\{CHP,EB\}} \tag{44}$$

$$\sum_{\vartheta} \sum_{q \in \{CHP,EB\}} H_{t,\vartheta,q}^{sor} - \sum_{l \in \{S_\vartheta^+, S_\vartheta^-\}} H_{t,l}^{loss} - \sum_{\vartheta} \sum_{d} H_{t,\vartheta,e}^{ho} = 0 \tag{45}$$

$$\begin{aligned} &T_{t,\vartheta,e}^{in} = T_{t-1,\vartheta,e}^{in} e^{\overline{\frac{-1}{(R/\mathrm{n}_{\vartheta,e}^{ho}).Cair_{\vartheta,e}}}} \\ &+(H_{t,\vartheta,e}^{ho}.R/\mathrm{n}_{\vartheta,e}^{ho} + T_t^{out}).(1 - e^{\overline{\frac{-1}{(R/\mathrm{n}_{\vartheta,e}^{ho}).Cair_{\vartheta,e}}}}) \forall t, \forall \vartheta, \forall e \end{aligned} \tag{46}$$

$$T_{\vartheta,e}^{\min} \leq T_{t,\vartheta,e}^{in} \leq T_{\vartheta,e}^{\max} \forall t, \forall \vartheta, \forall e \tag{47}$$

$$\underline{T_l^{DHS}} \leq T_{t.l}^{ps,out}, T_{t,l}^{ps,in} \leq \overline{T_l^{DHS}} \tag{48}$$

$$\underline{T_\vartheta^{DHS}} \leq T_{t.\vartheta}^{ms}, T_{t,\vartheta}^{mr} \leq \overline{T_\vartheta^{DHS}} \forall t, \forall l \tag{49}$$

$$H_{eb,t}^{EB} = \eta_{eb}^{EB} P_{eb,t}^{EB} \ \forall eb, \forall t \tag{50}$$

$$0 \leq P_{eb,t}^{EB} \leq \bar{P}_h^{EB} \ \forall eb, \forall t \tag{51}$$

$$\sum_k H_{k,t}^{DG} + \sum_{eb} H_{eb,t}^{EB} = H_{t,\vartheta,q}^{sor} \ \forall \vartheta, \forall q, \forall t \tag{52}$$

B. Natural gas market operator (Follower)

The objective function of the NGMO (an independent follower) is defined via Eq. (53). As can be seen, it consists of three terms. The first and second ones define the costs of natural gas production and the cost of natural gas storage (GS), respectively. The last term represents the cost of energy that IESP bids to purchase. The limits of natural gas drawn from gas wells are imposed in Eq. (54). To convert the lower level followers into the equivalent KKT conditions, the problem should be linear and convex, which is the reason this study has adopted the model proposed by [30]. The gas flow is defined by Eqs. (55)-(56) for active and non-active pipelines, respectively. The natural gas consumption limit of IESP is defined in Eq. (57). The GS model is established in Eqs. (58)-(61), while (Eq. (62) defines the energy equilibrium of the NGN.

$$\min \sum_t \left\{ \sum_w C_w^{gas} q_{w,t} + \sum_e C_e^{GS} q_{e,t}^{in} - \sum_k C_{k,t} G_{k,t}^{GFU} \right\} \tag{53}$$

$$0 \le q_{w,t} \le q_w^{\max}; \beta_{w,t}^{1,\max} \beta_{w,t}^{1,\min} \forall w, \forall t \tag{54}$$

$$-q_{\lg}^{\max} \le q_{\lg,t} \le q_{\lg}^{\max}; \beta_{\lg,t}^{2,\max} \beta_{\lg,t}^{2,\min} \forall \lg, \forall t \tag{55}$$

$$0 \le q_{c,t} \le q_c^{\max}; \beta_{c,t}^{c,\max} \beta_{c,t}^{c,\min} \forall c, \forall t \tag{56}$$

$$0 \le G_{k,t}^{GFU} \le G_K^{\max}; \beta_{k,t}^{3,\max}, \beta_{k,t}^{3,\min} \forall k, \forall t \tag{57}$$

$$GS_{e,t} = GS_{e,t-1} + q_{e,t}^{in} - q_{e,t}^{out}; \rho_{e,t} \forall e, \forall t > 1 \tag{58}$$

$$0 \le q_{e,t}^{in} \le q_e^{in,\max}; \beta_{e,t}^{4,\max} \beta_{e,t}^{4,\min} \forall e, \forall t \tag{59}$$

$$0 \le q_{e,t}^{out} \le q_e^{out,\max}; \beta_{e,t}^{5,\max} \beta_{e,t}^{5,\min} \forall e, \forall t \tag{60}$$

$$GS_e^{\min} \le GS_{e,t} \le GS_e^{\max}; \beta_{e,t}^{6,\max}, \beta_{e,t}^{6,\min} \forall e, \forall t \tag{61}$$

$$\begin{array}{l} \sum\limits_{w \in A_n^w} q_{w,t} + \sum\limits_{\{.\} \in \varphi_n^+} q_{\{.\},t} - \sum\limits_{\{.\} \in \varphi_n^-} q_{\{.\},t} - \sum\limits_{k \in A_n^k} G_{k,t}^{GFU} \\ - \sum\limits_{dg \in A_n^{dg}} q_{dg,t} + \sum\limits_{e \in A_n^e} (q_{e,t}^{out} - q_{e,t}^{in}) = 0; \gamma_{n,t} \\ \{.\} \in \{\lg, c\}, \forall n, \forall t \end{array} \tag{62}$$

C. Wholesale electricity market operator (Follower)

Equation Eq. (63) defines the objective function of WEMO (an independent follower), which is modelled by a TN. The terms of the equation contain energy production cost of Gencos, and the cost of energy offered or bided by IESP. The energy equilibrium of TN is ensured by Eq. (64). The capacity boundaries of Gencos are enforced by Eq. (65), while Eqs. (66)-(69) restrict their ramp up/down rates. The transactional limits of IESP are declared in Eq. (70). Eventually, Eqs. (71)-(72) impose the maximum power flow of the transmission lines and voltages angles.

$$\min \left\{ \sum_t \sum_g C_g^G P_{g,t}^G - \sum_t \sum_g C_t^{IESP} P_t^{IESP} \right\} \tag{63}$$

$$\begin{array}{l} \sum\limits_{g \in A_n^g} P_{g,t}^G - P_t^{IESP} - P_{b,t}^D = \sum\limits_{b' \in Tr} B_{b,b'} (\delta_{b,t} - \delta_{b',t}) \\ : \lambda_{b,t} \forall b, \forall t \end{array} \tag{64}$$

$$0 \le P_{g,t}^G \le P_{g,t}^{GMax} : \mu_{g,t}^{G\min}, \mu_{g,t}^{G\max} \forall g, \forall t \tag{65}$$

$$P_{g,t}^G - P_{g,t-1}^G \le RU_g : \mu_{g,t}^{1,\min} \forall g, \forall t > 1 \tag{66}$$

$$P_{g,t}^G - P_{g,ini}^G \le RU_g : \mu_{g,t}^{2,\min} \forall g, \forall t = 1 \tag{67}$$

$$P_{g,t-1}^G - P_{g,t}^G \le RD_g : \mu_{g,t}^{3,\min} \forall g, \forall t > 1 \tag{68}$$

$$P_{g,ini}^G - P_{g,t}^G \le RD_g : \mu_{g,t}^{4,\min} \forall g, \forall t = 1 \tag{69}$$

$$\underline{P_t^{IESP}} \le P_t^{IESP} \le \overline{P_t^{IESP}} : \mu_t^{IESP,\min}, \mu_t^{IESP,\max} \forall t \tag{70}$$

$$\begin{array}{l} -C_{b,b'}^{Max} \le B_{b,b'} (\delta_{b,t} - \delta_{b',t}) \le C_{b,b'}^{Max} \\ : \upsilon_{b,b',t}^{\min}, \upsilon_{b,b',t}^{\max} \forall b, \forall b', \forall t \end{array} \tag{71}$$

$$-\pi \le \delta_{b,t} \le \pi : \xi_{b,t}^{\min}, \xi_{b,t}^{\max} \forall b, \forall t \tag{72}$$

D. Mixed-integer linear programming

The problem discussed in this study is a nonlinear bi-level multi-follower model, which is reorganized as single-level problem using KKT conditions. The minutiae of this transformation are elaborated in [20]. The terms $\lambda_{i,t} P_t^{IESP}$ and $\gamma_{n,t} G_{k,t}^{GFU}$ are nonlinear statements that are linearized by the theory of strong duality as explained in the same reference. Finally, the ultimate problem formulation is established as follows:

$$\begin{array}{l} \min \sum\limits_t \left\{ \begin{array}{l} \sum\limits_{k \in NGU} (C_k^{DG} P_{k,t}^{DG} + SU_{k,t} + SD_{k,t}) \\ + \sum\limits_c C_c^{IL} P_{c,t}^{IL} + \sum\limits_e C_e^{DR} P_{e,t}^{DR} \end{array} \right\} \\ + X_1 + X_2 \end{array} \tag{73}$$

s.t Upper-level constraints: Eqs. (1)-(52)

Lower-level constraints: Eqs. (58),(62) , (64) and KKT linearized conditions. Where, X_1 and X_2 are the linearized terms of non-linear terms related to the costs of purchasing electricity and natural gas from the wholesale markets of electricity and natural gas, respectively.

E. Information gap decision theory

the IGDT approach gives the operator a chance to take more robust actions even though it might come with higher cost values. In other words, the operators are enabled to define the amount of cost that they are willing to endure for the sake of reliability. The overall framework is mathematically established as follows:

$$\max \{\alpha\} \tag{74}$$

$$OF_b = \{OF : \min OF\} \tag{75}$$

$$OF \le OF_b (1 + \varsigma), 0 \le \varsigma \le 1 \tag{76}$$

$$0 \le P_t^{RES} \le (1 - \alpha) \bar{P}_t^{RES}, P_t^{RES} = P_{r,t}^{Wind,\max} + P_{pv,t}^{PV,\max} \tag{77}$$

wherein ς is the risk-aversion parameter and α defines the uncertainty radius. Here, this risk-averse IGDT approach is utilized to model the uncertain output power of the RES in the IESP problem.

IV. Case studies and results

In this study, the IESP is modelled by an integrated IEEE-33 bus ADS and an 8-node DHS. The NGMO and WEMO are established through a 20-node NGN and a 6-node TN. The overall topology schematic of the systems, connections and nodal location of the components are depicted in Fig. 2. As illustrated, the IESP is comprised of three CHP units, two NGU, three PVAs and four WTs at ADS side, while the DHS side is made up of 6000 AHs, which are restricted to the temperature interval of 18.0 °C-25.0 °C which is the reason they are considered as flexible thermal loads. Technical information about the ADS can be extracted from [21], while technical data regarding the DHS and AH is listed in [31]. DHS, ADS and NGN are connected through CHP1-3. Technical information on NGN is represented in [32]. The NGN is supplied through two gas wells, which have the production costs of 5$/KCF and 7.5 $/KCF, respectively. Additionally, the 6-bus TN is a standard IEEE system with three Gencos, two non-responsive load nodes and seven transmission lines [33]. The ADS is connected to TN through a substation and the cost of IL, DRP and RES are 180, 2 and 1.25 ($/MWh), respectively. The proposed model is a mixed-integer linear problem (MILP), which is solved via CPLEX 12.5.1 under GAMS environment. With an Intel(R) Core (TM) i5-8250U CPU @ 1.60 GHz (4 CPUs), RAM 8 GB system, the solution procedure takes 2.5 minutes on average, which is compatible with the requirements of such a large-scale problem. Both absolute and relative optimization gabs are set to be zero [34]. The problem is investigated under following four case studies:

1) Case study 1 (**CS1**): The strategic participation of the IESP in WEM and NGM, excluding the flexible thermal/electrical loads.
2) Case study 2 (**CS2**): The strategic participation of the IESP in WEM and NGM considering the flexible thermal loads.
3) Case study 3 (**CS3**): The strategic participation of the IESP in WEM and NGM considering the flexible thermal/electrical loads.
4) Case study 4 (**CS4**): The IGDT-based strategic participation of the IESP in WEM and NGM with flexible thermal/electrical loads.

Hourly scheduling of ADS in **CS1**, **CS2** and **CS3** is demonstrated by Fig. 3-Fig. 5 Based on Fig. 3-Fig. 4, including the temperature flexibility of AH in **CS2** has increased the electrical output of the CHP1 and CHP3 by 19.11% and 28.45%, respectively (In comparison with **CS1**). The reason for this upsurge is the interdependency between the thermal and electrical outputs of the CHP units. Hence the flexible thermal loads open up the capacity for electrical production. In **CS3**, the integration of DRP by IESP has shifted the load from peak to off-peak intervals as illustrated by Fig. 5.

Thermal load scheduling of ADS in two cases is illustrated in Fig. 6-Fig. 7, wherein the line graphs and the bar charts represents AH temperature and thermal dispatch of CHP and EBs. In **CS1**, the AH temperature is assumed to be constant 25.0 °C. Hence the output power of the thermal sources is fixed at peak hours. In **CS2**, however, the AH temperature is a flexible variable restricted in the interval of 18.0 °C to 25.0 °C. As can be noticed, during off-peak electricity hours, CHPs have more thermal capacity. Therefore, during hours (24 to 7) the AH temperature increases, reaching 25.0 °C at hour 7. At this point, the CHP units reduce their thermal output until the AH temperature drops back to 18.0 °C, meaning that the AH are utilized as thermal energy storages. Compared to **CS1**, this temperature flexibility in **CS2** has reduced the thermal output of CHP1 and CHP3 by 19.11% and 28.45%.

Fig. 8 and Fig. 9 illustrate the scheduling of Gencos in WEM considering three cases. The production costs of Genco1 and Genco3 are less than that of Genco2. Based on these figures, the AH thermal flexibilities in **CS2** increase the electrical power production of the CHP units. A higher portion of the load is therefore satisfied through local distributed CHPs and the energy import of IESP from WEM has dropped. As a result, the production of the Genco2 has plummeted by 12.82% with respect to **CS1**. Moreover, the DRP in **CS3**, shifts the IESP demand to cheap off-peak market ours, thereby leading to a 20.02% reduction in the Genco2 production (expensive unit). Particularly, primary Gencos do not demonstrate any notable variation through different cases, as they are designed to satisfy the base load of the system. Fig. 10 provides a comparative perspective on the MCP of WEM in three cases. The aforementioned power reduction in **CS2** leads to a 1.96% drop in MCP of this case compared to **CS1**. Furthermore, integration of DRP in **CS3** diminishes the output power of expensive Gencos, resulting in a 5.89% reduction in the MCP. In NGM, on account of the fact that all expensive wells are active during the whole 24h period, there is not a perceivable variation in MCP among various cases and it is equal to 7.5$/Kcfh.

The total operational costs of IESP in three different cases are summarized in Table II. As mentioned, the thermal flexibilities of AH in **CS2** increase the output power of the CHP units. Therefore, the energy imported from WEM drops by 7.43%, while overall cost is decreased by 2.59% in comparison to **CS1**. Furthermore, in **CS3**, DRP shifts the demand to cheaper off-peak periods, thereby leading to a 4.06% reduction in overall cost. Nonetheless, DRP does not exert a notable influence on the MCP of NGM.

TABLE II: Operation costs in the three cases

	CS1	CS2	CS3
NGFDUs ($/MWh)	14411.93	14816.33	15246.61
RES($/MWh)	171.0584	171.0584	171.0584
IL ($/MWh)	7220.922	6216.261	5464.858
Purchased power from market ($/MWh)	9937.47	9198.555	8810.608
Purchased GAS from market ($/KCfh)	5047.81	5435.408	5546.495
DRP ($/MWh)	0	0	56.0939
Total cost ($/MWh)	36789.19	35837.61	35295.72

In **CS4**, IGDT is deployed to handle uncertainties of RES. The risk-averse behavior of the IESP is summarized in Table III and Table IV. As can be noticed, increasing the risk-aversion parameter in IGDT, the radius of uncertainty increases. In other words, IESP prefers to conduct scheduling based on the lower end of uncertainty spectrum. Consequently, IESP increases the production of the units and the energy purchase from WEM as a countermeasure. Evidently, these

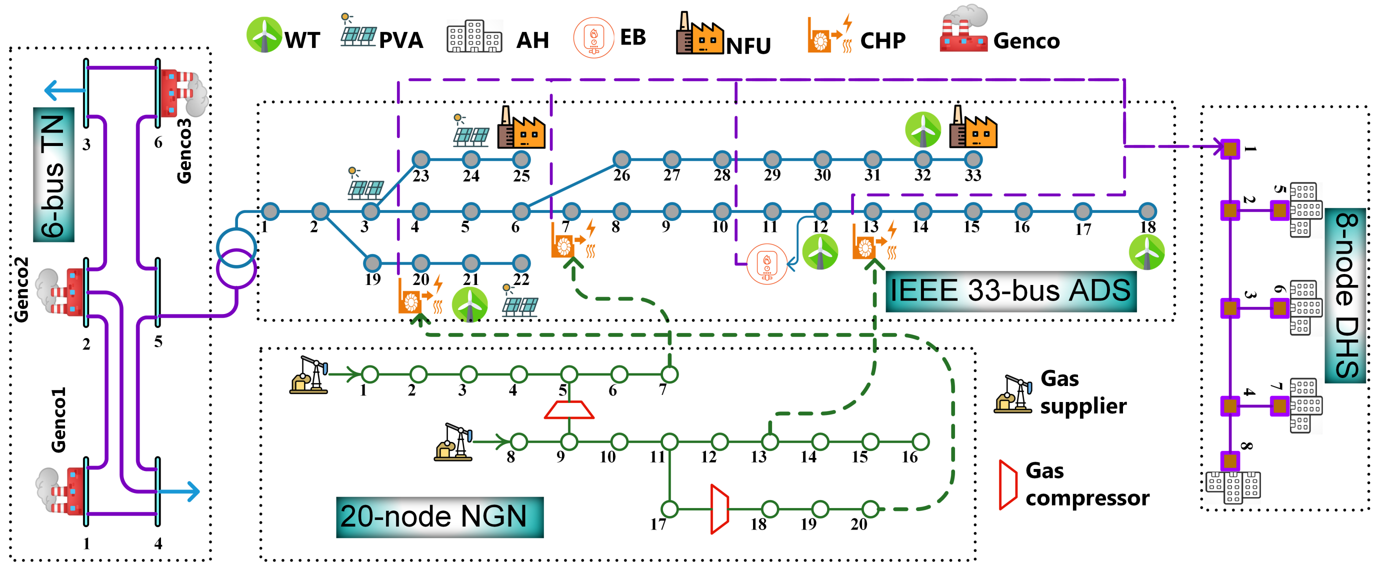

Fig. 2: The overall topology schematic of the IESP and its connections with WEM and NGM

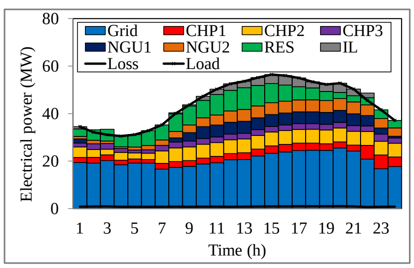

Fig. 3: Power balance of ADS in **CS1**

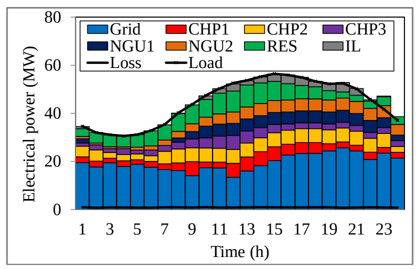

Fig. 4: Power balance of ADS in **CS2**

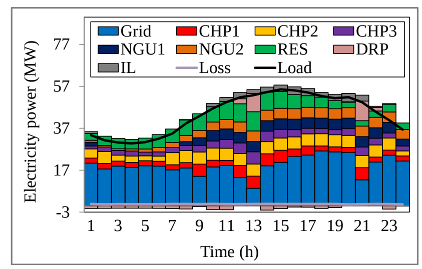

Fig. 5: Power balance of ADS in **CS3**

TABLE III: Sensitivity analysis of risk-aversion parameter on different cost values in IESP

	$\xi = 0$	$\xi = 0.05$	$\xi = 0.1$	$\xi = 0.15$	$\xi = 0.2$	$\xi = 0.25$	$\xi = 0.3$
NGFDUs ($/MWh)	15246.61	15809.72	16299.98	16876.76	17188.54	17563.95	18138.69
RES($/MWh)	171.0584	141.0768	113.6375	86.9593	58.2974	33.80995	14.95449
Interruptible load ($/MWh)	5464.858	6631.119	7961.439	9116.257	10034.11	11464.04	12472.96
Purchased power from market ($/MWh)	8810.608	9011.328	9230.188	9447.771	9811.854	9980.141	10226.49
Purchased GAS from market ($/KCfh)	5546.495	5627.141	5597.444	5655.092	5693.873	5726.249	5659.675
DRP ($/MWh)	56.0939	57.15349	58.45951	59.65321	53.21221	55.62698	53.33489
Total cost ($/MWh)	35295.72	37277.54	39261.15	41242.5	42839.89	44823.81	46566.1
Alpha	0	0.200328	0.380565	0.534879	0.666591	0.789983	0.900285

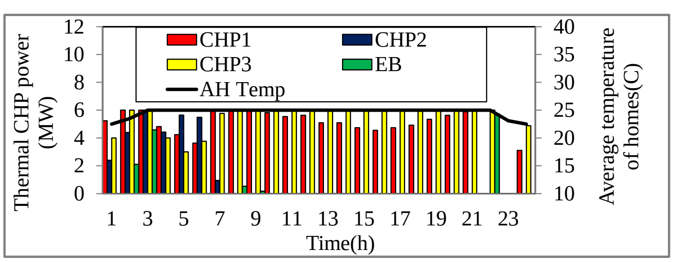

Fig. 6: Thermal energy balance of the DHS and AH temperature in **CS1**

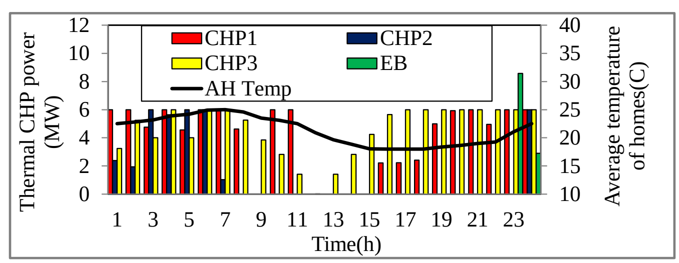

Fig. 7: Thermal energy balance of the DHS and AH temperature in **CS2**

conservative actions lead to higher cost values. To evaluate the impact of NGN pipeline congestion on IESP, a sensitivity analysis is evaluated as illustrated by Table V. According to the results, stepwise increments in natural gas demand up to 30% leads to a 6.5% reduction in the amount of natural gas purchased by IESP, which is the direct impact of line congestion. Consequently, the natural gas delivery to CHP units is obstructed with each incremental step in natural gas demand. In an attempt to satisfy load demand, IESP is forced to purchase more energy from WEM and shed interruptible loads. As a result, increasing natural gas demand in the NGM, means higher operational cost and augmented ADS power

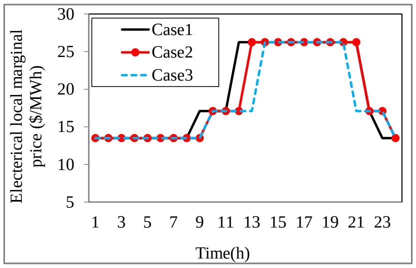

Fig. 8: Output power of Genco2 in the three cases

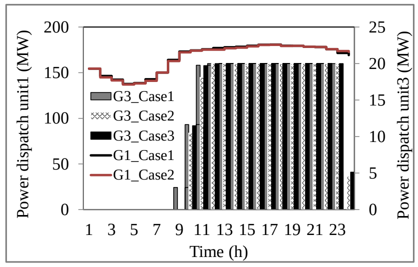

Fig. 9: Output power of Genco1 and 3 in the three cases

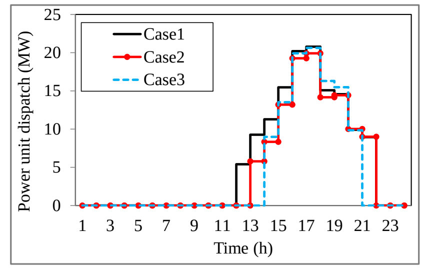

Fig. 10: Market clearing price in the three cases

TABLE IV: Sensitivity analysis of risk-aversion parameter on the output power of the units and the energy purchased from WEM.

	$\sum_t P_t^{IESP}$	$\sum_t RES_t$	$\sum_{t,g} P_{k,t}^{DG}$	$\sum_{t,c} P_{c,t}^{IL}$
$\xi = 0$	465.6599	136.8467	447.1551	30.36032
$\xi = 0.05$	473.2698	113.0737	458.1278	36.7833
$\xi = 0.1$	483.309	91.27206	461.3848	44.09156
$\xi = 0.15$	494.4866	70.18474	471.7547	50.45957
$\xi = 0.2$	502.254	47.40205	477.871	55.5648
$\xi = 0.25$	507.9273	27.85246	485.0552	63.30867
$\xi = 0.3$	511.5728	12.68149	486.91	68.88956

TABLE V: Sensitivity analysis of natural gas demand on operational parameters of the IESP.

	0%	**10%**	**20%**	**30%**
$\sum_t P_t^{IESP}$	465.6599	467.058	468.4297	578.1821
$\sum_{c,t} P_{c,t}^{IL}$	30.36032	30.91449	31.66021	46.37204
$\sum_{i,j,t} P_{i,j,t}^{Loss}$	19.95984	20.00193	20.14715	24.82609
$\sum_{k \in CHP_1,t} P_{k,t}^{DG}$	82.19925	81.55124	80.06565	62.38711
$\sum_{k \in CHP_2,t} P_{k,t}^{DG}$	121.9186	120.7401	118.8038	111.5932
$\sum_{k \in CHP_3,t} P_{k,t}^{DG}$	73.48725	73.40353	73.45972	0
$\sum_{k \in NGFDU_1,t} P_{k,t}^{DG}$	80.4	80.4	80.4	81.5162
$\sum_{k \in NGFDU_2,t} P_{k,t}^{DG}$	89.15006	89.15006	89.14994	100.7316
$\sum_{k,t} GFU_{k,t}$	739.5327	734.9355	727.4974	477.3429
$\sum_{i,t} \lambda_{i,t}$	438.4733	438.4733	438.4733	460.38

losses for IESP.

V. Conclusion

This study investigated a bi-level multi-follower optimization framework for strategic scheduling of an IESP in WEM and NGM as a price-maker player. At the upper-level, the IESP's operational and participation costs in the WEM and NGM is minimized, while WEMO and NGMO, as the lower-level followers, individually clear the NGM and WEM intending to maximize community welfare. Eventually, the IGDT approach was integrated to deal with uncertain RES production. Overall, the following conclusions can be drawn from the results:

1) The most important outcome of the proposed framework was to illustrate how the decisions of various operators can have mutual impacts. For instance, applying DRP to the IESP problem alters the Genco scheduling in the WEM. Similarly, increasing the natural gas consumption in NGM, rises the MCP in WEM.
2) AHs' temperature flexibilities enhanced the operational region of the CHP units and increased their electrical capacity, which leads to a substantial decline in MCP.
3) Integrating DRP in the IESP problem reduces the MCP, as it shifts the demand from peak to off-peak periods that are cheaper.
4) When the IESP incorporates risk-averse IGDT framework, the problem is scheduled for the lower end of the RES production spectrum to gain more conservative solutions, even though it leads to higher cost values.

The high computational burden of the model and the lack of newly emerging electric vehicles, can be listed as its main downsides. As a prospect for future studies, using decentralized optimization methods and assessing the resiliency of the system for possible contingencies (e.g., earthquakes, floods, terrorist incidents) offers a promising research ground.

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