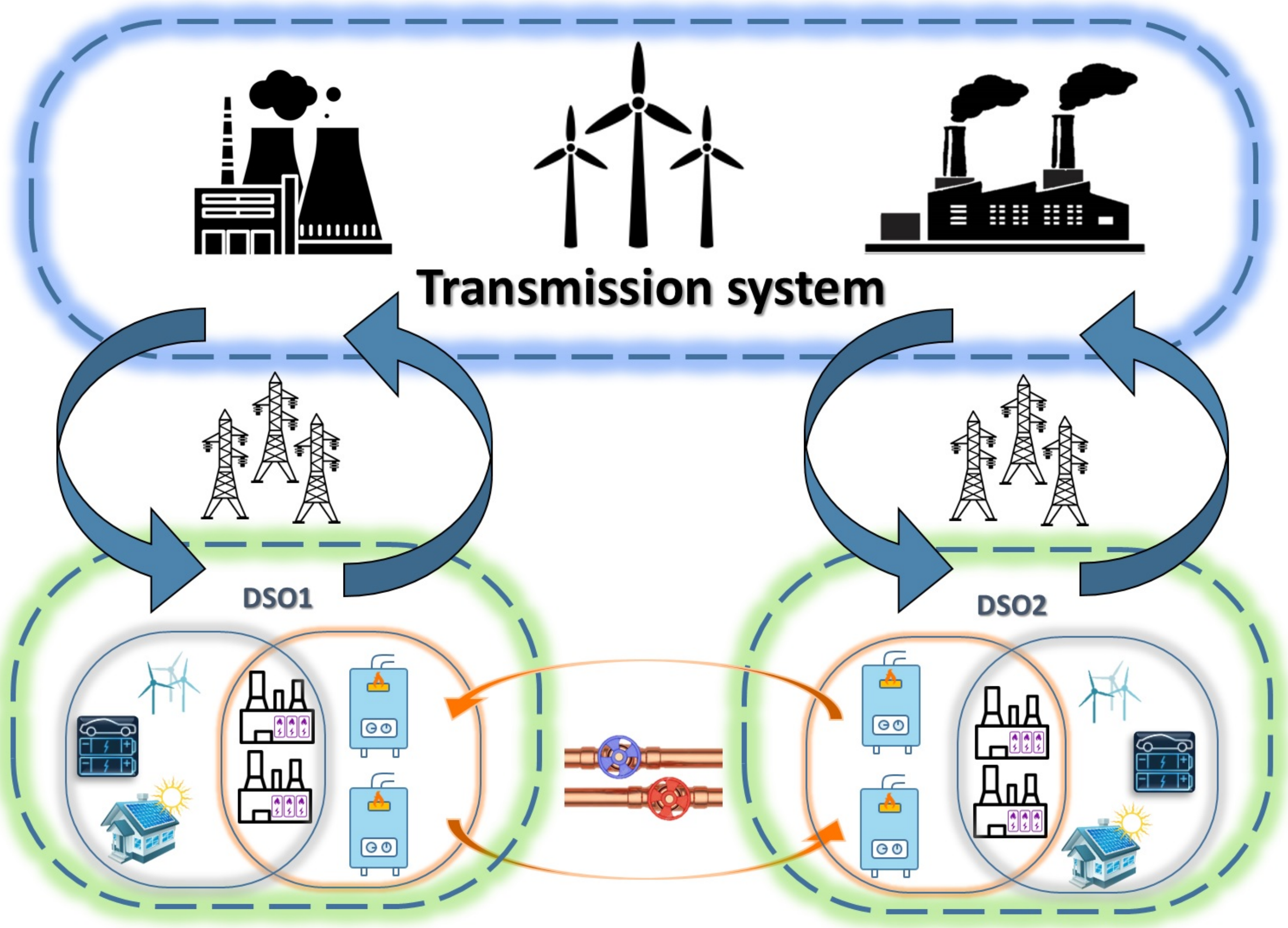
This is a peer-reviewed, accepted author manuscript of the following research article: Habibi, M., Vahidinasab, V., & Sepasian, M. S. (2022). Value of integrated electricity and heat scheduling with considering TSO–DSO cooperation. International Journal of Electrical Power and Energy Systems, 135, Article 107526. https://doi.org/10.1016/j.ijepes.2021.107526

# Graphical Abstract

## Energy Market for Heat and Electricity Power Considering TSO-DSO Cooperation

Mahdi Habibi,Vahid Vahidinasab,Mohammad Sadegh Sepasian



# Highlights

## Energy Market for Heat and Electricity Power Considering TSO-DSO Cooperation

Mahdi Habibi,Vahid Vahidinasab,Mohammad Sadegh Sepasian

- Developing an integrated heat and electricity market considering TSO-DSO cooperation.
- Considering limited heat transfer capacity between neighboring heating systems.
- Calculating shares of different market parties using intermediary variables and LMPs.
- Improving security and efficiency by coordinating the performance of market agents.

# Energy Market for Heat and Electricity Power Considering TSO-DSO Cooperation⋆

Mahdi Habibi[a], Vahid Vahidinasab[a,b,*] and Mohammad Sadegh Sepasian[a]

[a] *Faculty of Electrical Engineering, Shahid Beheshti University, Tehran, Iran*
[b] *The School of Engineering, Newcastle University, Newcastle upon Tyne NE1 7RU, United Kingdom*

ARTICLE INFO

*Keywords*:
Integrated electricity and heat markets
multi energy systems
combined heat and power (CHP) unit
TSO-DSO cooperation
energy transfer
locational marginal price
distributed generation

Abstract

The active role of distribution system operators (DSOs) coordinated with the transmission system operator (TSO) is highlighted by increasing the competition of new parties in energy markets. Besides, combined heat and power (CHP) units are the main heat suppliers of a district heating system, and their electricity production is strongly coupled with heat productions. This paper considers an integrated market for the heat and electric power considering TSO-DSO cooperation to increase the efficiency of the day-ahead scheduling. To increase market liquidity, the proposed model facilitates the energy transaction between systems with different agents by considering intermediary variables. Also, the corresponding costs of every market parties are separately calculated, and they are compared to the case of isolated operation of energy systems. The proposed model is applied to the modified IEEE 24-bus test system, in which it contains distribution systems and district heating systems. The result shows that the proposed model successfully reduces the operational costs compared to the isolated models. Also, the model facilitates energy trading between market parties.

## 1. Introduction

With the proliferation of small-sized distributed energy resources at the distribution network level, there are some parts of the grid capacities in both electricity and heat energy networks that remain unused while they can be traded between networks [1–3]. The electricity and heat energy networks have been integrated several years ago through the Combined Heat and Power (CHP) technology as a vector-coupling element [4, 5]. This paper looks for an integrated market model for electricity and heat energy systems. The proposed model will consider energy systems and the capacity of energy trading between the grids' interfaces and by considering the active cooperation of the Distribution System Operators (DSO) with the Transmission System Operator (TSO).

In conventional organizations, distribution systems play a passive role in electricity markets as fixed loads or pre-defined generation capacity based on the estimated operation points [6–8]. The separated model reduces the liquidity of markets and does not reflect the constraints of the downstream network that can be lead to interruptions [9]. In this regard, the cooperation of TSO and DSOs is established for electricity networks [9–11]. The data management problem of TSO-DSO is considered by a hierarchical model in [9]. That model studies an electricity market, and the sequential process has a slow convergence. Reference [10] proposed the decentralized management of DSOs' coordinated with TSO with considering the privacy of sharing sensitive information. An approach to exploit ancillary services from active distribution systems is described in [11], in which the power flow over interfaces is controlled by operators.

There is a strong link between the heat and electricity supplies, while the CHP units provide a large proportion of thermal energy in the heating systems [12, 13]. Also, the electric and gas boilers are the alternative sources for the heating network [14]. On the other hand, the dispatched values of electricity and heat can be affected by the market price signals for different energies [15]. The electricity and heat energy systems belong to different companies [16], but the energy market considering multi-energy systems can reach holistic solutions. Also, the integration of different energy systems with electricity networks can increase efficiency and reduces power imbalances [17]. The integrated heating and electricity systems are studied in [18], in which the model analyzes the performance of CHP units in reducing wind power curtailment at the transmission level. The operation of multi-energy systems is evaluated for transmission power systems integrated with gas and district heating networks in [19]. The active management of the distribution system and transferring energy between heating systems are not considered in that model. The heat loss limits the centralized operation of heating systems; hence, heat energy markets are usually operated by local DSOs [12]. Although heating networks are operated by the decentralized organization, any imbalances can affect electricity networks at different levels. Authors of [20] present an integrated model of electricity and district heating systems, which it considers the dynamic behavior of the thermal network. Meanwhile, a multi-regional operation of heating systems is presented in [21], in which the model considers transmission and distribution levels for supplying hot water. Reference [22] studied the flexibility services of CHP units provided by using energy storage tanks of centralized and decentralized models of heating systems at the distribution network level.

Table 1 compares existing publications in the area and highlights the research gaps, and also shows the novelties of the present paper. To the best of the knowledge of the authors, there is no model for integrated heat and electricity markets, which considers TSO-DSO cooperation. Also, market liquidity as an important factor in TSO-DSO coordination is widely investigated only for electricity networks. This paper will cover the above gaps by considering TSO-DSO cooperation in multi-energy systems.

This paper presents an Integrated Heat and Electricity Unit Commitment (IHE-UC) considering TSO-DSO cooperation. The proposed model considers the CHP unit as a vector-coupling element of electricity and heat energy systems. In addition to CHP units, the nonelectric boilers are applied as an alternative source for heat supply in the heating system, and Conventional Generators (CGs), Distributed Generators (DGs), and wind farms are the other electricity suppliers. The district heating systems are considered with a limited Capacity of Heat Transfer (CHT)

*Corresponding author
m_habibi@sbu.ac.ir ( Mahdi Habibi); vahid.vahidinasab@newcastle.ac.uk ( Vahid Vahidinasab); m_sepasian@sbu.ac.ir ( Mohammad Sadegh Sepasian)

**Table 1**
Comparison of this paper with existing related publications.

| References | CHPs | Boilers | Wind | E & H Coordination | TSO-DSO Coordination | CHT for DSOs | Calculating Share of Systems in -Energy Trading | | Operation Model |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Electricity | Heat | |
| [1] | – | – | – | – | – | – | – | – | Day-ahead UC |
| [2] | – | – | ✓ | – | – | – | – | – | Day-ahead UC |
| [3] | – | – | ✓ | – | – | – | – | – | Day-ahead UC |
| [4] | ✓ | – | ✓ | – | – | – | – | – | Economic Dispatch |
| [5] | ✓ | ✓ | ✓ | ✓ | – | – | – | – | Day-ahead UC |
| [6] | – | – | ✓ | – | – | – | – | – | Day-ahead UC |
| [7] | – | – | – | – | ✓ | – | ✓ | – | OPF |
| [8] | – | – | ✓ | – | ✓ | – | ✓ | – | Day-ahead UC |
| [9] | – | – | – | – | ✓ | – | – | – | Economic Dispatch |
| [10] | – | – | – | – | ✓ | – | ✓ | – | OPF |
| [11] | – | – | ✓ | – | ✓ | – | – | – | Power Flow |
| [12] | ✓ | ✓ | ✓ | ✓ | – | ✓ | – | – | Economic Dispatch |
| [13] | ✓ | ✓ | ✓ | ✓ | – | – | – | – | Day-ahead UC |
| [14] | ✓ | ✓ | – | ✓ | – | – | – | – | OPF |
| [15] | ✓ | ✓ | – | ✓ | – | – | – | – | OPF |
| [16] | ✓ | – | ✓ | ✓ | – | – | – | – | Day-ahead UC |
| [17] | ✓ | – | ✓ | ✓ | – | – | – | – | Day-ahead UC |
| [18] | ✓ | – | ✓ | ✓ | – | – | – | – | OPF |
| [19] | ✓ | ✓ | ✓ | ✓ | – | – | – | – | Economic Dispatch |
| [20] | ✓ | ✓ | ✓ | ✓ | – | – | – | – | OPF |
| [21] | ✓ | – | ✓ | ✓ | – | – | – | – | OPF |
| [22] | ✓ | – | – | ✓ | – | – | – | – | Economic Dispatch |
| [23] | ✓ | – | – | ✓ | – | – | – | – | OPF |
| **This paper** | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | **Day-ahead UC** |

to neighboring systems. The proposed model evaluates the interconnection of different energy systems and at different levels by considering intermediary variables for energy trading. The trading of different forms of energy will improve energy delivery and reduces the cost of energy supply. Also, the proposed model will obtain the share of different market players using Locational Marginal Electricity Price (LMEP) and Local Marginal Heat Price (LMHP). The main contributions of this paper are summarized as follows:

- To develop a model for the integrated market for the electricity and heat energy systems considering the cooperation of TSO and DSOs;
- To consider limited capacities of heat transfer to neighboring heating systems for improving efficiency and liquidity of the market;
- To calculate the share of different market parties using intermediary variables of energy transfer and locational marginal electricity and heat prices.

The rest of this paper is organized as follows. The model of IHE-UC considering TSO-DSO cooperation is described in Section 2. Section 3 evaluates the results of the implementation of the proposed model, and Section 4 concludes the paper.

# 2. Model of IHE-UC with TSO-DSO cooperation

The proposed integrated model of TSO and DSOs is presented in this section. The interconnected formulation of the grid under the supervisory of TSO and DSOs are described separately. Besides, the model of CHP units is described as the integrator of heating and electricity networks. Additionally, the proposed IHE-UC model and the breakdown of the cost are reflected at the end of this section.

## 2.1. Model description at TSO level

The TSO operates the upstream electrical grid and regularly determines the commitment of generation capacity located at the transmission network. The operational cost at the TSO level includes the cost of CGs, which is presented by (1). The regular constraints of start-up/shut-down, the minimum duration of online and offline of CGs, production limits, and ramp rates are presented by (2)-(7). The maximum available wind production based on estimated values and the limits for curtailment of wind energy are considered by (8). The power flow of transmission lines is calculated based on the DC power flow by (9).

$$of_t^{\mathrm{TSO}} = \sum_g \left[ f(st_{g,t}, sd_{g,t}) + f(p_{g,t}^{\mathrm{CG}}, i_{g,t}^{\mathrm{CG}}) \right] \quad (1)$$

$$st_{g,t} - sd_{g,t} = i_{g,t}^{\mathrm{CG}} - i_{g,(t-1)}^{\mathrm{CG}} \quad (2)$$

$$i_{g,\tau}^{\mathrm{CG}} \geq st_{g,t} \quad \forall t \leq \tau \leq t + T_{g,\mathrm{on}}^{\min} - 1 \quad (3)$$

$$1 - i_{g,\tau}^{\mathrm{CG}} \geq sd_{g,t} \quad \forall t \leq \tau \leq t + T_{g,\mathrm{off}}^{\min} - 1 \quad (4)$$

$$P_g^{\mathrm{CG,min}} i_{g,t}^{\mathrm{CG}} \leq p_{g,t}^{\mathrm{CG}} \leq P_g^{\mathrm{CG,max}} i_{g,t}^{\mathrm{CG}} \quad (5)$$

$$p_{g,t}^{\mathrm{CG}} - p_{g,(t-1)}^{\mathrm{CG}} \leq Ru_g^{\mathrm{CG}} i_{g,t}^{\mathrm{CG}} + Su_g st_{g,t}^{\mathrm{CG}} \quad (6)$$

$$p_{g,(t-1)}^{\mathrm{CG}} - p_{g,t}^{\mathrm{CG}} \leq Rd_g^{\mathrm{CG}} i_{g,t}^{\mathrm{CG}} + Sd_g sd_{g,t}^{\mathrm{CG}} \quad (7)$$

$$(1-\alpha) P_{w,t}^{\mathrm{WD,max}} \leq p_{w,t}^{\mathrm{WD}} \leq P_{w,t}^{\mathrm{WD,max}} \quad (8)$$

$$\left| fl_{l,t}^{\mathrm{Tr}} = S_{\mathrm{base}} (\delta_t^{\mathrm{From}(l)} - \delta_t^{\mathrm{To}(l)}) / X_l \right| \leq Fl_l^{\mathrm{Tr,max}} \quad (9)$$

The injected power to the distribution system is considered through the intermediary free variable of $p_{D,t}^{Inj}$, in which it can be negative in the case of injection power to the transmission system. The intermediary variable is limited by (10), and the power balance at the transmission system is considered by (11). The different sets are defined to locate the connection points of facilities to the grid, and the power injection to the distribution system is reflected by a negative sign.

$$\left|p_{D,t}^{\text{Inj}}\right| \leq P_{D,t}^{\text{Inj,max}} \tag{10}$$

$$\sum_{g\in\gamma} p_{g,t}^{\text{CG}} + \sum_{w\in\varphi} p_{w,t}^{\text{WD}} + \sum_{T} fl_{l,t}^{\text{Tr}} - \sum_{D\in\upsilon} p_{D,t}^{\text{Inj}} = P_{b,t}^{\text{Load}} \tag{11}$$

## 2.2. Model of DSOs – electricity and heat systems

The proposed model includes the electricity and heating systems, and it considers intermediary variables for electricity and heat power trading with TSO and other DSOs. The cost function of DSOs is presented by (12), in which it contains the cost of both electricity and heat productions. The operational costs of electricity and heat are calculated by (13) and (14), respectively. The constraints of DGs, including generation limits and ramp rates, are considered by (15)-(17), and (18) calculates the power flow of distribution lines. The power balance at different buses is presented by (19), while the injection power to distribution systems is added with a positive sign.

$$of_{D,t}^{\text{DSO}} = of_{D,t}^{E} + of_{D,t}^{H} \tag{12}$$

$$of_{D,t}^{E} = \sum_{dg\in\zeta} f(p_{dg,t}^{\text{DG}}) + \sum_{c\in\beta} f(p_{c,t}^{\text{CHP}}, i_{c,t}^{\text{CHP}}) \tag{13}$$

$$of_{D,t}^{H} = \sum_{h\in\psi} f(q_{h,t}^{\text{BO}}, i_{h,t}^{\text{BO}}) + \sum_{c\in\beta} f(q_{c,t}^{\text{CHP}}, i_{c,t}^{\text{CHP}}) + \sum_{D'} f(q_{D,D',t}^{\text{Imp}}, q_{D,D',t}^{\text{Exp}}) \tag{14}$$

$$0 \leq p_{dg,t}^{\text{DG}} \leq P_{dg,t}^{\text{DG,max}} i_{dg,t}^{\text{DG}} \tag{15}$$

$$p_{dg,t}^{\text{DG}} - p_{dg,(t-1)}^{\text{DG}} \leq Ru_{dg}^{\text{DG}} i_{dg,t}^{\text{DG}} \tag{16}$$

$$p_{dg,(t-1)}^{\text{DG}} - p_{dg,t}^{\text{DG}} \leq Rd_{dg}^{\text{DG}} i_{dg,t}^{\text{DG}} \tag{17}$$

$$\left|fl_{ld,t}^{\text{Dis}} = S_{\text{base}}(\delta_t^{\text{From}(ld)} - \delta_t^{\text{To}(ld)})/X_{ld}\right| \leq Fl_{ld}^{\text{Dis,max}} \tag{18}$$

$$\sum_{dg\in\mu} p_{dg,t}^{\text{DG}} + \sum_{c\in\lambda} p_{c,t}^{\text{CHP}} + \sum_{ld\in Z} fl_{ld,t}^{\text{Dis}} + \sum_{D\in\Gamma} p_{D,t}^{\text{Inj}} = P_{bd,t}^{\text{Load}} \tag{19}$$

The feasible area for heat and electricity generations of CHP units is presented by vertex polygon in Fig. 1, where the point of $(Q_{c,2},P_{c,2})$ represents the maximum output power of units [15, 16, 23]. The electricity and heat power of CHP units based on the feasible operational area can be presented as follows:

$$p_{c,t}^{\text{CHP}} = \sum_{k} x_{c,t}^{k} P_{c,k}^{\text{CHP}} \tag{20}$$

$$q_{c,t}^{\text{CHP}} = \sum_{k} x_{c,t}^{k} Q_{c,k}^{\text{CHP}} \tag{21}$$

Where the combination variable of $x_{c,t}^{k}$ determines the production of CHP units, and it is limited by (22). Also, for all c and t, the sum of $x_{c,t}^{k}$ must be equal to one (the binary variable of $i_{c,t}^{CHP}$) if CHP units are online in the resulting schedule for the proposed IHE-UC.

$$0 \leq x_{c,t}^{k} \leq 1 \tag{22}$$

$$\sum_{k} x_{c,t}^{k} = i_{c,t}^{\text{CHP}} \tag{23}$$

The heat power trading between district heating systems is considered by (25)-(28), where $q_{D,D',t}^{\text{Trans}}$ consists of import and export variables. The intermediary variable of heat trading is defined as a free variable, and the negative values indicate the

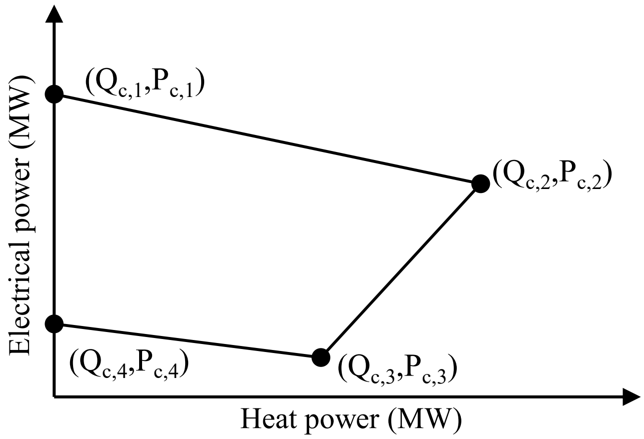



**Figure 1:** Feasible area of heat and electric power in CHP units.

reverse heat power flow. Equation (25) implies that heat power takes the opposite sign at receiving distribution systems. The import and export of heat power are limited by CHT, as presented by (26) and (27), respectively. The nonelectric boiler is the alternative source of heat power in the heating system, and their generation is limited by (28). Also, the balance of heat power considering intermediary variables is presented by (29).

$$q_{D,D',t}^{\text{Trans}} = q_{D,D',t}^{\text{Imp}} - q_{D,D',t}^{\text{Exp}} \tag{24}$$

$$q_{D,D',t}^{\text{Trans}} = -q_{D',D,t}^{\text{Trans}} \tag{25}$$

$$0 \leq q_{D,D',t}^{\text{Imp}} \leq THC_{D,D'} \tag{26}$$

$$0 \leq q_{D,D',t}^{\text{Exp}} \leq THC_{D,D'} \tag{27}$$

$$0 \leq q_{h,t}^{\text{BO}} \leq q_{h}^{\text{BO,max}} i_{h,t}^{\text{BO}} \tag{28}$$

$$\sum_{h\in\psi} q_{h,t}^{\text{BO}} + \sum_{c\in\beta} q_{c,t}^{\text{CHP}} + \sum_{D'\in\eta} q_{D,D',t}^{\text{Trans}} = Q_{D,t}^{\text{Load}} \tag{29}$$

## 2.3. IHE-UC with TSO-DSO cooperation

The proposed model of the integrated heat and electricity market is described as follows:

$$\min_{\substack{p,q,i\\ st,sd}} \sum_{t} \left( of_{t}^{\text{TSO}} + \sum_{D} of_{D,t}^{\text{DSO}} \right) \tag{30}$$

$$\text{S.t.} \quad (1) - (29)$$

Where the objective function minimizes the total operational costs of TSO and DSOs. Also, the state variables are electricity and heat power generations of different units alongside binary variables of online/offline and start-up/shut-down statuses.

## 2.4. Market clearing organization

The objective function (30) optimizes the overall cost of the power system, it is essential to calculate the separated costs of different agents. In order to achieve this goal, the LMEP and LMHP are used to calculate the share of different market parties. The LMEPs in transmission and distribution networks are the dual variables of (11) and (19), respectively. Also, the LMHPs are the dual variables of (29), and are calculated per distribution systems. After solving the IHE-UC problem, the values of LMEPs and calculated state variable (with hat sign) are used to obtain the total cost of TSO as follows:

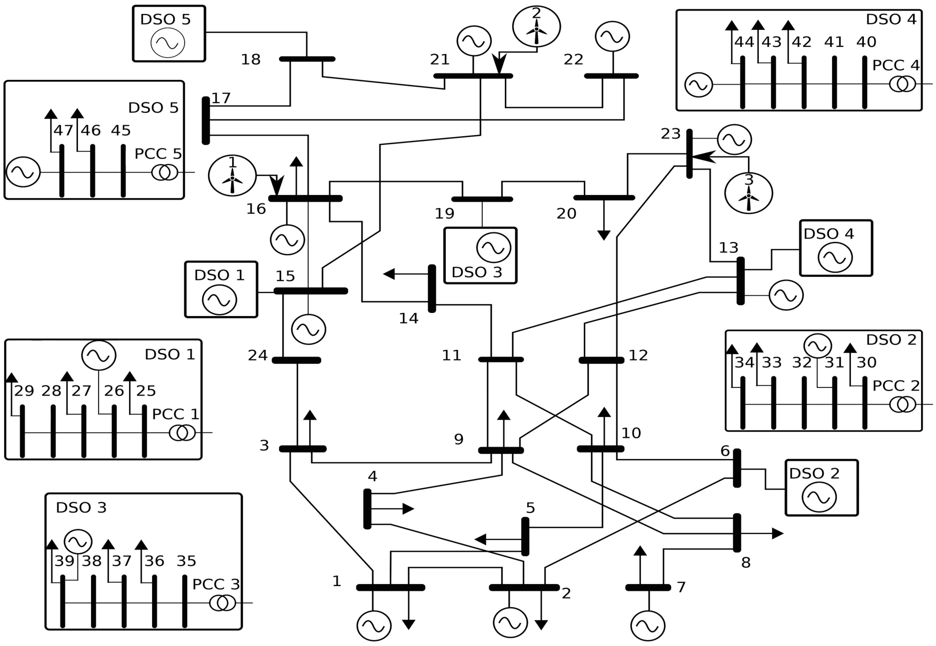



**Figure 2:** Diagram of the modified IEEE 24-bus test system with 5 linked distribution systems.

**Algorithm 1** Market Clearing

Solve IHE-UC (31) subject to (1)–(30) using GAMS
Fix state variables of optimization problem
**for** $t = 1, 2, \dots$ **do**
  Fix $LMEP_t^{bd}$ (dual vaiable of Eq. (20))
  Calculate $of_t^{TSO}$ using state variables and $LMEP_t^{bd}$
  **for** $D = 1, 2, \dots$ **do**
    Calculate $of_{D,t}^{E}$ using state variables and $LMEP_t^{bd}$
    Fix $LMHP_t^{D}$ (dual variable of Eq. (30))
    Calculate $of_{D,t}^{H}$ using state variables and $LMHP_t^{D}$
    Calculate $of_{D,t}^{DSO}$ using Eq. (13)
  **end for**
**end for**

$$of_t^{\text{TSO}} = \sum_{g} \left[ f(\hat{st}_{g,t}, \hat{sd}_{g,t}) + f(\hat{p}_{g,t}^{\text{CG}}, \hat{i}_{g,t}^{\text{CG}}) \right] - \sum_{bd \in \kappa} \left( L\hat{M}EP_t^{bd} \sum_{D \in \Gamma} \hat{p}_{D,t}^{\text{Inj}} \right) \quad (31)$$

Additionally, the LEMPs and LMHPs are used to calculate DSOs' costs of electrical and heating systems, as presented by (32) and (33). The total operational cost of DSOs can be achieved by (12). The procedure of calculating the share of market parties in operational cost is presented in Algorithm 1.

$$of_{D,t}^{E} = \sum_{dg \in \zeta} f(\hat{p}_{dg,t}^{\text{DG}}) + \sum_{c \in \beta} f(\hat{p}_{c,t}^{\text{CHP}}, \hat{i}_{c,t}^{\text{CHP}}) + \sum_{bd \in \kappa} \left( L\hat{M}EP_t^{bd} \sum_{D \in \Gamma} \hat{p}_{D,t}^{\text{Inj}} \right) \quad (32)$$

$$of_{D,t}^{H} = \sum_{h \in \psi} f(\hat{q}_{h,t}^{\text{BO}}, \hat{i}_{h,t}^{\text{BO}}) + \sum_{c \in \beta} f(\hat{q}_{c,t}^{\text{CHP}}, \hat{i}_{c,t}^{\text{CHP}}) + \sum_{D'} f(\hat{q}_{D,D',t}^{\text{Imp}}, \hat{q}_{D,D',t}^{\text{Exp}}) + \sum_{D'} L\hat{M}HP_t^{D} (\hat{q}_{D,D',t}^{\text{Imp}} - \hat{q}_{D,D',t}^{\text{Exp}}) \quad (33)$$

**Table 2**
Specifications of different case studies.

| | Specifications |
|---|---|
| Case-1 | Separated energy markets with HSO priority |
| Case-2 | Separated energy markets with ESO priority |
| Case-3 | Integrated energy market without CHT |
| Case-4* | Integrated e nergy market with CHT |

*Proposed model of this paper

## 3. Simulation Results

This section will examine the proposed model of the integrated heat and electricity market. The IEEE 24-bus test system is used with some modifications for studying TSO-DSO cooperation. Three wind farms are added to the transmission system. Also, five distribution systems are added to the standard test system, in which they consist of different energy production technologies of DGs, CHP units, and nonelectric boilers. Besides, limited heat transferring capacities are only considered between DSO-1 and DSO-3, and between DSO-3 and DSO-4. The additional data of the test system is provided in [24]. The diagram of the electrical section of the modified test system is presented in Fig. 2. The General Algebraic Modeling System (GAMS) is employed for the implementation of the proposed model using a laptop with Intel i7-core 2.4 GHz and 8 GB of RAM.

The case studies of Table 2 are considered to compare the performance of the integrated model against the separated one for a heat and electricity market. The base model for all cases is an integrated model of the energy market for TSO and DSOs. In Case-1, Heating System Operator (HSO) initially runs the heat energy market independent of the electricity market, and Electricity System Operator (ESO) uses that operation point to calculate the electric power dispatches. Case-2 is the opposite of Case-1, and the electricity market takes priority over the scheduling of the heating network. Case-3 examines the model's performance without considering the heat transfer capacity between neighboring systems. Finally, The proposed model of this paper

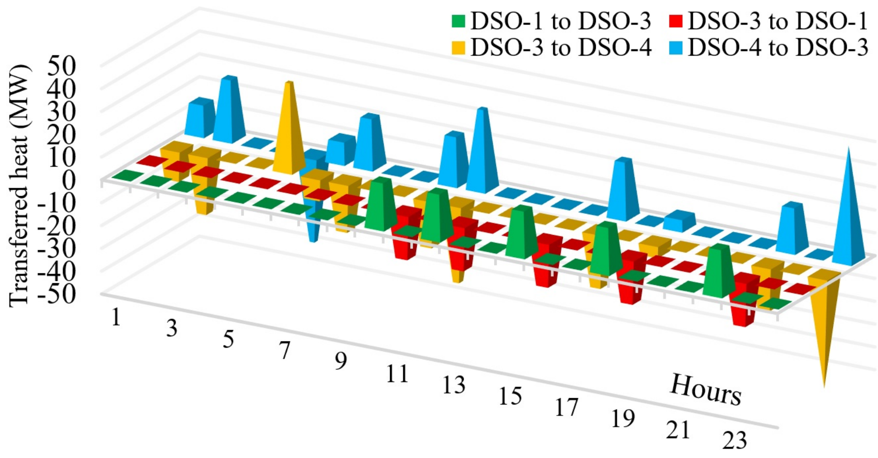



**Figure 3:** Heat power transfer between district heating networks.

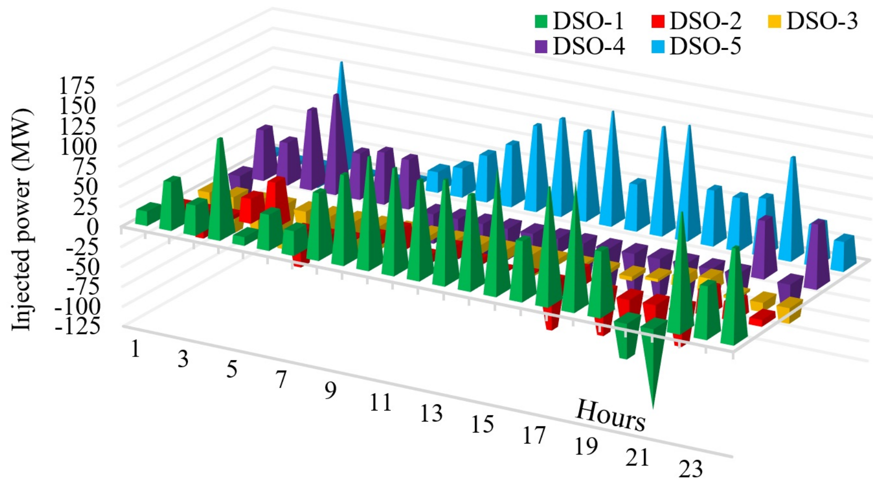



**Figure 4:** Injection of electricity to the distribution systems.

is evaluated in Case-4, which it considers an integrated model for heat and electricity markets with possible transferring heat energy between specific distribution systems. In the following, the analysis and comparison of case studies are performed in different aspects.

It is important to calculate the share of various market players (including the share of DSOs) in operating costs, taking into account the TSO-DSO cooperation and the integration of heat and electricity systems. In this regard, the operational costs are compared based on different perspectives in Table 3. It should be noted, about 100 MW of electricity in Case-1 and about 609 MW of heat in Case-2 are curtailed in distribution systems. The penalties for heat and electricity curtailments are not reflected in the results due to easier comparisons. As expected, separate market organizations in Case-1 lead to the lowest operating cost for the heating system, where Case-2 calculates the lowest cost for the electricity market. In Case-2, the total operational cost and the share of DSOs are higher than in Case-1. Besides, if the cost of energy curtailments is added to current values, the total cost of DSOs in Case-2 will be much higher. This is because most CHP units are dedicated to generating electricity, and the shortage of heat energy in Case-2 has increased.

As can be seen, the costs of the integrated model are reduced by considering the CHT for all market players. Also, Case-4 shows slightly higher values for heating and electricity

**Table 3**
Comparison of operational cost ($).

| | Case-1 | Case-2 | Case-3 | Case-4 |
|---|---|---|---|---|
| Heat | 364,896 | 395,200 | 370,367 | 369,393 |
| Electricity | 996,730 | 980,103 | 986,188 | 985,093 |
| All DSOs | 842,304 | 877,234 | 889,065 | 888,317 |
| TSO | 519,322 | 498,068 | 467,490 | 466,169 |
| Total | 1,361,626 | 1,375,302 | 1,356,555 | 1,354,485 |

costs compared to Case-1 and Case-2, respectively. The reason is that the model considers the integration of energy networks in Case-4. The same justification can be applied to the share of TSO and DSOs, and the result shows that the proposed model leads to the lowest value $1,354,485 for the total operational cost. Additionally, the comparison of Case-3 and Case-4 shows that Case-4 leads to lower costs for all market players.

Table 4 presents the share of different technologies in the total cost of the DSOs for the model proposed in this paper. The positive value (payment) for the cost of exchanging electrical energy at the junction of TSOs and DSOs indicates that electric power is being injected from the TSO to the DSOs, and the negative sign (revenue) indicates the reverse direction of power flow. The values of payments and revenues show that DSOs export and import electricity at their interfaces at different hours.

**Table 4**
Cost of different technologies for each DSO in Case-4 ($).

| | | DSO-1 | DSO-2 | DSO-3 | DSO-4 | DSO-5 | Sum |
|---|---|---|---|---|---|---|---|
| DG | | 13,167 | 22,386 | 0 | 55,308 | 11,7625 | 20,8486 |
| CHPs | | 127,271 | 143,055 | 125,096 | 101,159 | 135,934 | 632,515 |
| Boiler | | 8,714 | 0 | 1,271 | 7,701 | 19,300 | 36,986 |
| P-Inject | *Pay. | 24,581 | 4,076 | 1,179 | 10,065 | 22,156 | 62,057 |
| | **Rev. | -5,644 | -14,269 | -7,783 | -23,181 | -850 | -51,727 |
| Q-Trans | Pay. | 1,972 | 0 | 904 | 4,280 | 0 | 7,156 |
| | Rev. | 0 | 0 | -6,252 | -904 | 0 | -7,156 |
| Total | | 170,061 | 155,248 | 114,415 | 154,428 | 294,165 | 888,317 |

*Payment / **Revenue

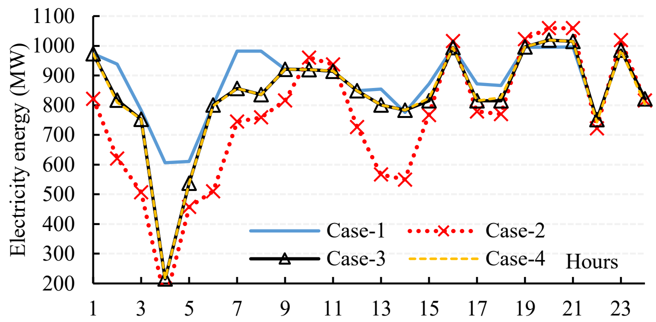



**Figure 5:** Electricity power production of CHP units.

Heat transfer payments and revenues show that DSO-1 only imports heat energy ($1,972), but DSO-3 and DSO-4 both export and import heat energy at different hours. Also, the total operational costs of DSOs have been calculated using LMEPs and LMHPs, and the obtained values can be assigned to the relevant distribution systems in the market clearing mechanism.

The determination of the amount of power exchange between networks of TSO and DSOs, preserving the limits of tie-lines, is very important in the integrated market models. Hence, the injection of electricity to the distribution systems is reported in Fig. 4. It shows that distribution systems DSO-1, DSO-4, and DSO-5 mostly import electric power (up to 151 MW) from the upstream network, while DSO-2 and DSO-3 are the main exporters of electricity (up to 68 MW) to the transmission system. Fig. 3 shows the amount of transferred heat between district heating systems. The heating systems DSO-1 and DSO-4 send the thermal power to DSO-3, and the power is transferred from DSO-3 to DSO-4 at hour 5.

As mentioned, the CHP units integrate heating and electricity networks. The electricity generation and thermal energy of CHP units have been compared in different cases in Fig. 5 and Fig. 6, respectively. Fig. 5 shows that the electricity generation of CHP units is higher in Case-1 and lower in Case-2 compared to the Case-4. The reason is that the electricity values calculated in Case-1 and Case-2 are based on the priority of heat and electricity markets, respectively. The result of Case-2 shows that ESO prefers lower amounts of electric power (with the minimum value of 215 MW) for CHP units in a few hours, while the higher values (up to 1020 MW) are used at hours 9, 20, and 21.

Fig. 6 presents the hourly heat generation of CHP units and compares the different cases. As can be seen, the curve of Case-4 locates between Case-1 and Case-2. However, the heat production in Case-4 (413 MW) is lower than in both Case-1 and Case-2 (1140 MW) at hour 4. The reason for the decrease in heat power generation can be explained by the interconnection of CHP productions and the low electricity generation of CHP units at hour 4 based on Fig. 5.

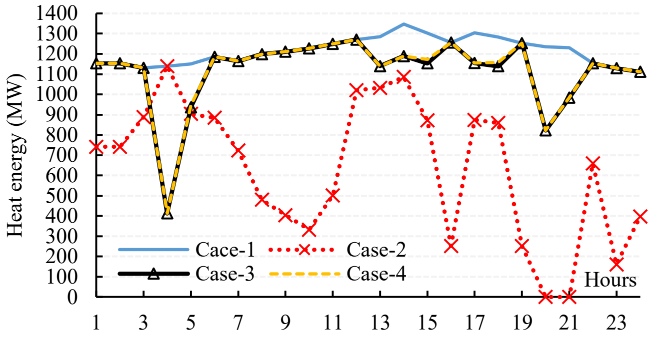



**Figure 6:** Heat power production of CHP units.

**Table 5**
Wind Forecast Data.

| | P-Electricity (MW) | | | | | Q-Heat (MW) | | |
|---|---|---|---|---|---|---|---|---|
| Time | Gen | Wind | Inject | DG | CHP | Boiler | CHP | Trans |
| 1 | 1472 | 263 | 88 | 134 | 974 | 0 | 1153 | 14 |
| 2 | 1448 | 304 | -33 | 118 | 810 | 0 | 1153 | 26 |
| 3 | 1249 | 267 | -6 | 86 | 753 | 0 | 1131 | 0 |
| 4 | 1186 | 181 | -325 | 43 | 215 | 727 | 413 | 0 |
| 5 | 1199 | 231 | -128 | 62 | 538 | 202 | 948 | 38 |
| 6 | 1308 | 236 | 18 | 94 | 798 | 0 | 1185 | 10 |
| 7 | 1472 | 381 | -29 | 134 | 856 | 0 | 1164 | 22 |
| 8 | 1547 | 619 | -135 | 166 | 836 | 0 | 1199 | 0 |
| 9 | 1542 | 685 | -91 | 182 | 921 | 0 | 1211 | 0 |
| 10 | 1578 | 870 | -156 | 206 | 920 | 0 | 1227 | 41 |
| 11 | 1589 | 858 | -130 | 251 | 916 | 0 | 1249 | 35 |
| 12 | 843 | 1529 | -184 | 190 | 850 | 0 | 1270 | 20 |
| 13 | 715 | 1559 | -191 | 174 | 801 | 145 | 1139 | 0 |
| 14 | 644 | 1500 | -166 | 158 | 783 | 158 | 1189 | 0 |
| 15 | 1384 | 1133 | -226 | 232 | 824 | 129 | 1173 | 20 |
| 16 | 1589 | 756 | -1 | 316 | 994 | 0 | 1256 | 25 |
| 17 | 1471 | 972 | -229 | 194 | 815 | 149 | 1155 | 0 |
| 18 | 1446 | 1047 | -176 | 294 | 827 | 124 | 1158 | 25 |
| 19 | 2032 | 436 | -20 | 353 | 996 | 0 | 1253 | 0 |
| 20 | 2128 | 336 | 88 | 496 | 1020 | 412 | 822 | 0 |
| 21 | 2192 | 290 | 122 | 564 | 1015 | 247 | 984 | 0 |
| 22 | 1681 | 1017 | -354 | 214 | 743 | 0 | 1153 | 39 |
| 23 | 2107 | 239 | -80 | 202 | 986 | 0 | 1129 | 0 |
| 24 | 2030 | 314 | -208 | 182 | 804 | 0 | 1112 | 50 |

The dispatches of energy resources, including the heat and electricity, are presented in Table 5. It can be seen that the injection of electricity into the distribution grid and heat transfer between district heating systems are varied during the operation period. Also, during most hours, CHP units produce more heat than electricity, except at hours 21 and 22, which coincide with the peak-loads of electrical systems. The result shows that the heat production of boilers in most hours is less than CHP units except at hour 4 (with 727 MW for boilers). The reason is that the minimum hourly load of the electrical system occurs at hour 4, and the integration of heat and electricity productions limits the CHP heat output.

The average electricity prices at DSOs' connection points

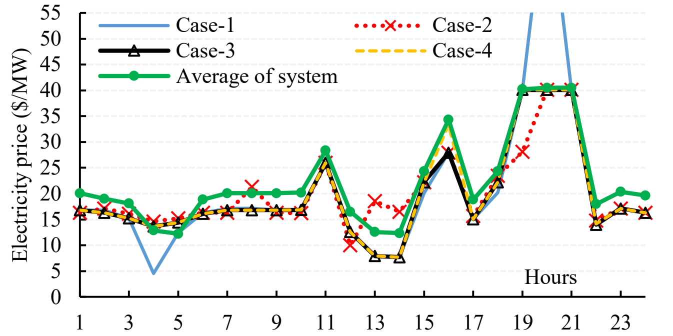



**Figure 7:** Average electricity price of distribution systems at connection points to upstream network in different cases and the overall average of electricity price.

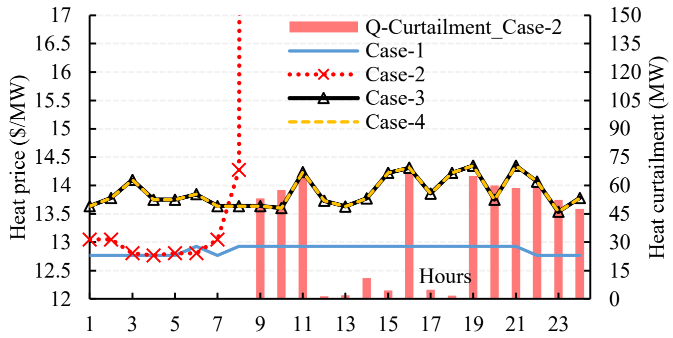



**Figure 8:** Hourly average heat price in different cases.

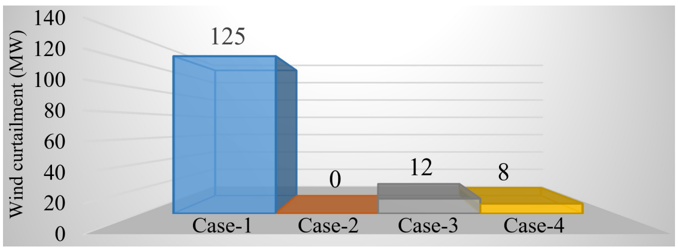



**Figure 9:** Wind power curtailment in different cases.

are compared for different cases in Fig. 7. In Case-1, the isolated energy market with HSO priority causes a spike of about 212 $/MW in the electricity price at hour 20. In cases 2-4, no spikes in the average electricity prices can be seen at the gate of distribution systems. Also, the average energy price of the whole system is reported in Fig. 7, which it is calculated between 12.2 $/MW and 40.5 $/MW.

The average heat prices of different cases are compared in Fig. 8. As expected, Case-1 takes the lowest price (about 12.8 $/MW) for heat energy. In contrast, heat price spikes of Case-2 (more than 200 $/MW) occur at hours 9 to 24 and (due to neglect of the heating system in the electricity market). In this regard, heat power curtailments happen at the same hours with spikes of heat price in Case-2. As can be seen, Case-4 obtained a reasonable curve for heat price (between 13.5 $/MW and 14.4 $/MW) as the proposed model of this paper.

The wind power curtailment for different cases is reported in Fig. 9. With 125 MW, the Case-1 takes the highest wind curtailment between all cases, and Case-2 absorbs all wind power with ESO as the prior system operator. In Case-4, about 8 MW wind power is curtailed during the 24 hours of operation period.

## 4. Conclusion

This paper presented an integrated heat and electricity unit commitment with coordinated TSO and DSOs operation. The model enables the transfer of heat and electricity between the networks, and CHP units increase the flexibility of both networks by playing a vector-coupling role between the energy systems. The evaluation of simulation results leads to the following conclusions:

- The proposed model improves the efficiency of scheduling by a bit reducing operational costs (about 0.5%) and unserved energies (up to 100 MW of electricity and 609 MW of heat) compared to the separated market organizations;
- By considering the dependency of heat and electricity energies through CHP units, the proposed model prevents the spikes of about 200 $/MW in the energy prices;
- The operational security is improved by considering the dependency of energy systems, and by checking the power flow limits of the tie-lines in the day-ahead market;
- The proposed model successfully calculates the operational costs of different market players, including the payments and revenues, by calculating the amount of energy and price of power trading at the junctions of energy systems.

Future work can involve uncertainties in energy systems at various levels. Additionally, the impact of CHP units in providing flexibility services in the distribution networks is of great interest for future studies.

## References

[1] Arash Baharvandi, Jamshid Aghaei, Ahmad Nikoobakht, Taher Niknam, Vahid Vahidinasab, Damian Giaouris, and Phil Taylor. Linearized hybrid stochastic/robust scheduling of active distribution networks encompassing pvs. *IEEE Transactions on Smart Grid*, 11(1):357–367, 2019.

[2] Mahdi Habibi, Vahid Vahidinasab, Adib Allahham, Damian Giaouris, Sara Walker, and Phil Taylor. Coordinated storage and flexible loads as a network service provider: a resilience-oriented paradigm. In *2019 IEEE 28th International Symposium on Industrial Electronics (ISIE)*, pages 58–63. IEEE, 2019.

[3] Mahdi Habibi and Vahid Vahidinasab. Emergency services of energy storage systems for wind ramp events. In *2019 Smart Grid Conference (SGC)*, pages 1–6. IEEE, 2019.

[4] Yuanhang Dai, Lei Chen, Yong Min, Qun Chen, Junhong Hao, Kang Hu, and Fei Xu. Dispatch model for chp with pipeline and building thermal energy storage considering heat transfer process. *IEEE Transactions on Sustainable Energy*, 10(1):192–203, 2018.

[5] Yongjie Zhong, Dongliang Xie, Suwei Zhai, and Yonghui Sun. Day-ahead hierarchical steady state optimal operation for integrated energy system based on energy hub. *Energies*, 11(10):2765, 2018.

[6] M. Habibi, V. Vahidinasab, A. Pirayesh, M. Shafie-khah, and J. P. S. Catalão. An enhanced contingency-based model for joint energy and reserve markets operation by considering wind and energy storage systems. *IEEE Transactions on Industrial Informatics*, pages 1–1, 2020.

[7] João Silva, Jean Sumaili, Ricardo J Bessa, Luís Seca, Manuel A Matos, Vladimiro Miranda, Mathieu Caujolle, Belen Goncer, and Maria Sebastian-Viana. Estimating the active and reactive power flexibility area at the tso-dso interface. *IEEE Transactions on Power Systems*, 33(5):4741–4750, 2018.

[8] Alexander Niels August Hermann. *Market-Based Methods For The Coordinated Use Of Distributed Energy Resources-TSO-DSO coordination in liberalized power systems*. PhD thesis, Technical University of Denmark, 2019.

[9] Zhao Yuan and Mohammad Reza Hesamzadeh. Hierarchical coordination of tso-dso economic dispatch considering large-scale integration of distributed energy resources. *Applied energy*, 195:600–615, 2017.

[10] Ali Mohammadi, Mahdi Mehrtash, and Amin Kargarian. Diagonal quadratic approximation for decentralized collaborative tso+ dso optimal power flow. *IEEE Transactions on Smart Grid*, 10(3):2358–2370, 2018.

[11] D Mayorga Gonzalez, J Hachenberger, J Hinker, F Rewald, U Häger, C Rehtanz, and J Myrzik. Determination of the time-dependent flexibility of active distribution networks to control their tso-dso interconnection power flow. In *2018 Power Systems Computation Conference (PSCC)*, pages 1–8. IEEE, 2018.

[12] Chenyu Wu, Wei Gu, Ping Jiang, Zhenyuan Li, Hongyi Cai, and Baoju Li. Combined economic dispatch considering the time-delay of district heating network and multi-regional indoor temperature control. *IEEE Transactions on Sustainable Energy*, 9(1):118–127, 2017.

[13] Xianzheng Huang, Zhaofeng Xu, Yong Sun, Yali Xue, Zhe Wang, Zhijun Liu, Zhenyuan Li, and Weidou Ni. Heat and power load dispatching considering energy storage of district heating system and electric boilers. *Journal of Modern Power Systems and Clean Energy*, 6(5):992–1003, 2018.

[14] Yang Li, Zhiyi Li, Fushuan Wen, and Mohammad Shahidehpour. Privacy-preserving optimal dispatch for an integrated power distribution and natural gas system in networked energy hubs. *IEEE Transactions on Sustainable Energy*, 10(4):2028–2038, 2018.

[15] Yue Chen, Wei Wei, Feng Liu, Enzo E Sauma, and Shengwei Mei. Energy trading and market equilibrium in integrated heat-power distribution systems. *IEEE Transactions on Smart Grid*, 10(4):4080–4094, 2018.

[16] Yuwei Chen, Qinglai Guo, and Hongbin Sun. Decentralized unit commitment in integrated heat and electricity systems using sdm-gs-alm. *IEEE Transactions on Power Systems*, 34(3):2322–2333, 2018.

[17] Yizhou Zhou, Mohammad Shahidehpour, Zhinong Wei, Zhiyi Li, Guoqiang Sun, and Sheng Chen. Distributionally robust unit commitment in coordinated electricity and district heating networks. *IEEE Transactions on Power Systems*, 35(3):2155–2166, 2019.

[18] Rongxiang Yuan, Jun Ye, Jiazhi Lei, and Timing Li. Integrated combined heat and power system dispatch considering electrical and thermal energy storage. *Energies*, 9(6):474, 2016.

[19] Jun Ye and Rongxiang Yuan. Integrated natural gas, heat, and power dispatch considering wind power and power-to-gas. *Sustainability*, 9(4):602, 2017.

[20] Houhe Chen, Ting Zhang, Rufeng Zhang, Tao Jiang, Xue Li, and Guoqing Li. Interval optimal scheduling of integrated electricity and district heating systems considering dynamic characteristics of heating network. *IET Energy Systems Integration*, 2020.

[21] Yuanhang Dai, Lei Chen, Yong Min, Pierluigi Mancarella, Qun Chen, Junhong Hao, Kang Hu, and Fei Xu. A general model for thermal energy storage in combined heat and power dispatch considering heat transfer constraints. *IEEE Transactions on Sustainable Energy*, 9(4):1518–1528, 2018.

[22] Thomas Nuytten, Bert Claessens, Kristof Paredis, Johan Van Bael, and Daan Six. Flexibility of a combined heat and power system with thermal energy storage for district heating. *Applied energy*, 104:583–591, 2013.

[23] Jinfu Zheng, Zhigang Zhou, Jianing Zhao, and Jinda Wang. Effects of the operation regulation modes of district heating system on an integrated heat and power dispatch system for wind power integration. *Applied Energy*, 230:1126–1139, 2018.

[24] Mahdi, Habibi and Vahid, Vahidinasab and Mohammad Sadegh, Sepasian. Integrated Heat and electricity systems with TSO-DSO cooperation, http://www.vahidinasab.com/data/TSO_DSO_HE_26AUG2020.zip, 2020.


# 5. Appendix A - Nomenclature

## Indices

| | |
|---|---|
| $b, bd, g,$ $w, dg, c, h$ | Indices of transmission/distribution buses, CGs, wind farms, DGs, CHPs, and nonelectric boilers. |
| CG, WD, DG CHP, BO | Indices of labels for generation technologies: CGs, wind farms, DGs, CHPs, and nonelectric boilers. |
| $D, D'$ | Indices of distribution systems. |
| $l, ld$ | Indices of transmission and distribution lines. |
| max, min | Indices of maximum/minimum limits of variables. |
| on, off | Indices of online/offline status of units. |
| $t, base$ | Index of time and base power. |
| TSO, DSO E, H | Indices of labels for transmission/distribution system operators and electrical/heating systems. |
| Tr, Dis | Indices of labels for transmission/distribution systems. |
| Trans, Imp Exp | Indices of labels for transferred, imported, and exported heat power between distribution systems. |

## Sets

| | |
|---|---|
| From, To | Sets of forwarding/receiving buses in transmission and distribution systems of lines $l / ld$. |
| $\kappa$ | Set of connection buses of transmission and distribution systems. |
| $\gamma, \varphi, T$ | Sets of CGs, wind farms, and lines connected to bus $b$. |
| $\zeta, \beta, \psi$ | Sets of DGs, CHPs, and nonelectric boilers connected to distribution system $D$. |
| $\mu, \lambda, Z$ | Sets of DGs, CHPs, and lines connected to bus $bd$. |
| $\eta$ | Set of neighboring systems with allowed heat transfer. |
| $\Omega$ | Set of buses $bd$ that they are connected point of $D$. |
| $\upsilon, \Gamma$ | Sets of distribution systems connected to buses $(b / bd)$. |

## Variables and functions

| | |
|---|---|
| $fl_{l,t}^{\text{Tr, Dis}}$ | Power flow of lines at transmission/distribution level networks (MW). |
| $f(\cdot)$ | Cost function of different technologies and services ($). |
| $of_{(\cdot)}^{(\cdot)}$ | Set of connection buses of transmission and distribution systems. |
| $i_{(g/dg/c/h),t}^{(\text{CG/DG/CHP/BO})}$ | Binary on/off status of generation technologies. |
| $p_{(g/w/dg/c),t}^{(\text{CG/WD/DG/CHP})}$ | Electrical generation of different technologies (MW). |
| $p_{D,t}^{Inj}$ | Electricity injection to distribution systems (MW). |
| $LMEP_t^{bd}$ | LMEP at different buses ($/MWh). |
| $LMHP_t^D$ | LMHP at different distribution systems ($/MWh). |
| $q_{(c/h),t}^{(\text{CHP/BO})}$ | Heat generation of different technologies (MW). |
| $q_{(D/D'),t}^{(\text{Trans/Imp/Exp})}$ | Heat trading between distribution systems (MW). |
| $x_{c,t}^k$ | Combination variable of CHP production. |
| $st_{g,t}, sd_{g,t}$ | Binary variables of generators' start-up/shut-down. |
| $\delta_t^b$ | Angle of voltage at different system levels (rad). |

## Constants

| | |
|---|---|
| $(Ru/Rd)_{g/dg}^{(\text{CG/DG})}$ | Ramp rate limits of CGs and DGs (MW). |
| $Fl_{(l,ld),t}^{(\text{Tr/Dis}),\max}$ | Lines' flow at transmission/distribution level (MW). |
| $Su_g, Sd_g$ | Start-up/shut-down ramp rates for CGs (MW). |
| $X_l, S_{base}$ | Reactance of lines and base power (p.u.). |
| $P_{w,t}^{\text{WD, max}}$ | Forecasted available wind power (MW). |
| $P_{c,k}^{\text{CHP}}$ | Maximum electric power of CHPs at vertex $k$ (MW). |
| $P_{(\cdot),t}^{(\cdot),(\max/\min)}$ | Generation limits of different technologies (MW). |
| $P_{(b/bd),t}^{\text{Load}}$ | Electrical loads of buses at different levels (MW). |
| $Q_{c,k}^{\text{CHP}}$ | Maximum heat power of CHPs at vertex k (MW). |
| $Q_{D,t}^{\text{Load}}$ | Heat loads at different distribution systems (MW). |
| $THC_{D,D'}$ | THC between heating systems (MW). |
| $T_{g,(\text{on/off})}^{\min}$ | Minimum online/offline duration of generators (h). |
| $\alpha$ | Maximum allowed curtailment rate of wind power. |