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Optimal Day-Ahead Scheduling of Integrated Urban Energy Systems

Xiaolong Jin^a, Yunfei Mu^{a*}, Hongjie Jia^a, Jianzhong Wu^b, Xiandong Xu^c, Xiaodan Yu^a

^aKey Laboratory of Smart Grid of Ministry of Education, Tianjin University, Tianjin 30072, China

^bInstitute of Energy, School of Engineering, Cardiff University, Cardiff CF24 3AA, UK

^cSchool of Electronics, Electrical Engineering and Computer Science, Queen's University Belfast, Belfast BT9 5 AH, UK

Email address: xljin@tju.edu.cn, yunfeimu@tju.edu.cn, hjjia@tju.edu.cn, wuj5@cardiff.ac.uk, x.xu@qub.ac.uk, yuxd@tju.edu.cn

*Corresponding author: Yunfei Mu: Tel.: +86-158-2250-9583; E-mail address: yunfeimu@tju.edu.cn

Abstract

An optimal day-ahead scheduling method (ODSM) for the integrated urban energy system (IUES) is introduced, which considers the reconfigurable capability of an electric distribution network. The hourly topology of a distribution network, a natural gas network, the energy centers including the combined heat and power (CHP) units, different energy conversion devices and demand responsive loads (DRLs), are optimized to minimize the day-ahead operation cost of the IUES. The hourly reconfigurable capability of the electric distribution network utilizing remotely controlled switches (RCSs) is explored and discussed. The operational constraints of the unbalanced three-phase electric distribution network, the natural gas network, and the energy centers are considered. The interactions among the above systems are described by an energy hub model. A hybrid optimization method based on genetic algorithm (GA) and a nonlinear interior point method (IPM) is utilized to solve the ODSM model. Numerical studies demonstrate that the proposed ODSM is able to provide the IUES with an effective and economical day-ahead scheduling scheme and reduce the operational cost of the IUES.

Keywords: Integrated urban energy system (IUES), energy center, combined heat and power (CHP) unit, reconfiguration, energy hub, day-ahead scheduling.

Abbreviations		$P_{e,\min}^{EH}, P_{e,\max}^{EH}$	Maximum and minimum limits of electric power exchange of the energy center.
ODSM	Optimal day-ahead scheduling method.	$P_{g,\min}^{EH}, P_{g,\max}^{EH}$	Maximum and minimum limits of natural gas power exchange of the energy center.
IUES	Integrated urban energy system.	P_{\max}^{DRL}	Maximum power reduction by DRLs.
CHP	Combined heat and power.	V_{\min}, V_{\max}	Maximum and minimum limits of the magnitude of bus voltage.
RCS	Remotely controlled switches.	i_{\max}^f	Upper current limit of electric feeder.
DRL	Demand responsive load.	p_{\min}, p_{\max}	Maximum and minimum limits of gas node pressure.
CAC	Central air-conditioning.	N_{loop}	Number of main loops in the electric distribution network.
Indices		k_{kn}	Parameter that depends on gas pipeline parameters, gas properties and gas temperature.
t	Index of time intervals.	$\eta_{ge}^{CHP}, \eta_{gh}^{CHP}$	Conversion efficiency of gas into electricity and heat through CHP unit.
i, j, N_{e-bus}	Indices and total number of electric buses.	η^{AC}	Thermal energy conversion rate of the CAC.
m, k, N_{g-bus}	Indices and total number of natural gas nodes.	η^{GB}	Efficiency of the gas-boiler.
N_{br}	Total number of electric feeders.	$P_{\varepsilon,\max}^{CHP}, P_{\varepsilon,\min}^{CHP}$	Upper and lower limits of the power output of the CHP unit.
$N_{pipeline}$	Total number of natural gas pipelines.	$P_{\varepsilon,\max}^{AC}, P_{\varepsilon,\min}^{AC}$	Maximum and minimum capacity of the CAC.
N_{EH}	Total number of energy hubs.	Variables	
N_{EH-I}, N_{EH-II}	Total number of type-I and type-II energy hubs.	P^{grid}	Day-ahead electric power purchases.
δ	Index of DRLs.	P^{gas}	Day-ahead natural gas purchases.
r	Index of RCSs.	P^{DRL}	Day-ahead power reduction by DRLs.
ε	Index of energy centers in IUES.	RCS	Vector of remotely controlled switch status.
Parameters and constants		N_{RCS}^{SW}	Switching actions for RCS.
C^e, C^g	Day-ahead wholesale electricity price and natural gas price.	P^{ε}	Active electric power flow of electric feeder.
C^{DRL}, C^{SW}	Day-ahead contract price of DRLs participation and cost of each switching action for RCSs.	V, S	Bus voltage and apparent power flow of electric feeder.
P_e^l	Other electric loads not supplied by the energy centers.	p, F^{fs}	Gas node pressure and gas pipeline flow.
L_e, L_h	Electric power and heat power output of the energy center.	P_e^{EH}, P_g^{EH}	Electric power and natural gas power exchange of the energy center.
Y, θ	Magnitude and phase angle of electric feeder's admittance.	v_e, v_g	Electric and natural gas partition coefficients.
$P_{\min}^{grid}, P_{\max}^{grid}$	Maximum and minimum limits of the day-ahead electricity purchase.	P^{PV}	Output of the photovoltaic panel.
$P_{\min}^{gas}, P_{\max}^{gas}$	Maximum and minimum limits of the day-ahead natural gas purchase.	P^{WT}	Output of the wind turbine.

26 1. Introduction

27 The increasing level of environmental pollution and depletion of fossil fuels are the two main factors
28 that restrict the development of future low-carbon cities [1]. In order to tackle these problems, more
29 and more attention has been paid on the integrated urban energy system (IUES) with couplings and
30 interactions among various energy systems (e.g. electric power systems, natural gas supply systems,
31 and heat systems) at the urban or community level [2] [3]. The IUES is able to coordinate the above
32 energy systems to provide new solutions for more secure, sustainable and economical energy
33 production, distribution and consumption in the future low-carbon cities [4].

34 The active elements (e.g. the electric distribution network with hourly reconfigurable topology
35 enabled by remotely controlled switches (RCSs) and the energy center including combined heat and
36 power (CHP) units, different energy conversion devices and demand responsive load (DRL)) endow
37 the IUES with a more flexible operation capability, which can realize a comprehensive utilization of
38 multiple energy resources. However, with an increasing penetration of renewable energy resources and
39 a large-scale adoption of electric vehicles (EVs) at the demand side [5]-[8], the efficiency and
40 reliability of both natural gas and electric distribution networks in the IUES are affected significantly.
41 Thus, the optimization, coordination and management of these active elements in various energy
42 systems are of significant importance for the integration of renewable energy and reducing the cost of
43 energy utilization for the IUES.

44 The energy resource scheduling plays an increasingly important role for the daily operation of
45 energy systems, which mainly focuses on unit commitment and economic dispatch. The optimal
46 scheduling approaches for various energy systems have been intensively studied, including power
47 systems [9]-[12], natural gas supply systems [13]-[15], and integrated energy systems [16]-[25].

48 ■ Power systems

49 Optimal scheduling approaches were developed for stochastic power systems [9], distribution
50 networks [10] and Microgrids [11] to seek the optimum scheduling solutions. A day-ahead stochastic
51 scheduling approach based on a chance-constrained stochastic programming was proposed in [9]. An
52 optimal scheduling and control model for a Microgrid was proposed in [11] taking several uncertainties
53 into consideration. It is worth noting that an optimal scheduling framework was proposed in [10] which
54 used the flexible topology of a distribution network as a control variable to increase the amount of
55 imported electric power with low electricity prices. More economic saving was realized because the
56 topology reconfiguration increased the electric power supply capability [12].

57 ■ Natural gas supply systems

58 An optimal scheduling model for a natural gas transmission network was developed in [13] to solve
59 the problem of transmitting natural gas at a minimum cost through a pipeline network under the
60 constraints of nonlinear flow-pressure relations, material balance equations and pressure bounds. A
61 dynamic programming-based tree decomposition algorithm was utilized in [14] to minimize the fuel
62 cost for natural gas transmission networks. A new geometric programming approach for optimizing the
63 operation in natural gas system was developed in [15].

64 ■ Integrated energy systems

65 The interactions between different energy systems at different scales were analyzed, including the
66 impact from pipeline faults of the natural gas system on the power system security [16] and the unit
67 commitment [17], *etc.* In this context, hourly optimal scheduling of integrated energy systems
68 (interdependent natural gas and electric power systems) with high penetration of wind energy [18] and
69 flexible hourly demand response [19] was proposed to determine the optimum day-ahead scheduling
70 solutions. Dynamic modeling and interaction of hybrid natural gas and electricity supply systems in a
71 Microgrid were studied in [20]. Operational scheduling of the Great Britain integrated gas and
72 electricity networks considering the uncertainties in wind power forecast was developed to reduce the
73 operation cost [21]. The optimal scheduling of IUES at the urban or community level was developed
74 based on an energy hub model [22]-[25]. An energy hub based optimization model of residential IUES
75 was presented in [22] to optimally control the residential energy loads, storage system and production
76 components considering the customer preferences and the comfort level. A general optimization
77 framework was presented for urban multiple energy carrier systems in [23]. A hierarchical energy
78 management system was designed for a community level Microgrid and IUES based on the energy hub
79 model in [24][25].

80 The existing research works have made good contributions to the scheduling of different energy
81 systems, especially power systems and natural gas systems, which are mature for engineering
82 applications. As to the IUES, the current research on optimal scheduling mainly concentrates on the
83 scheduling of energy generation and energy demand. The flexible reconfigurable topology of the
84 electric distribution network of the IUES was always neglected, which is conservative to some extent
85 for the operation cost reduction of the IUES. Actually, the topology of an electric distribution network
86 has close relationship with the scheduling scheme of the IUES [26]. Furthermore, the electric
87 distribution network of the IUES is generally characterized as an unbalanced three-phase system.
88 However, previous studies usually assumed that the IUES is balanced and the constraints from the
89 unbalanced three-phase electric distribution network were not considered in the optimal scheduling
90 solutions.

91 To solve the above problems, an optimal day-ahead scheduling method (ODSM) for an IUES
 92 considering the reconfigurable capability of an electric distribution network was developed. The hourly
 93 reconfigurable capability of the electric distribution network utilizing RCSs was explored and
 94 discussed. The interactions between the electric distribution network and a natural gas network of the
 95 IUES were represented by an energy hub model. The constraints of the unbalanced three-phase electric
 96 distribution network, the natural gas network, and the energy centers were considered in the ODSM. A
 97 hybrid optimization method based on genetic algorithm (GA) and a nonlinear interior point method
 98 (IPM) was utilized to solve the ODSM model. The ODSM allows the operators of the IUES to
 99 coordinate the interrelated power, gas, and heating systems, taking three-phase electric distribution
 100 network characteristics into account. Numerical studies shown that different energy systems were
 101 coordinated effectively and the operation cost of IUES was reduced.

102 2. Model of the integrated urban energy system (IUES)

103 An IUES is illustrated in Fig. 1, which involves three energy systems, i.e. an electric distribution
 104 system, a natural gas system and an energy center. The IUES purchases energy (electricity and natural
 105 gas) from different energy utilities and distributes them via the electric distribution network, the natural
 106 gas network and the energy center to satisfy the energy demand. At the energy demand side, the IUES
 107 signs bilateral contracts with DRLs for their participation in the provision of ancillary services for the
 108 IUES. The coupling relationships between the electric distribution network and the natural gas network
 109 are represented by the energy centers.

Fig. 1. Description of the IUES.

110 In this paper, an energy hub model is utilized to describe the energy center, which includes the CHP
 111 unit, the power transformers, the central air-conditionings (CACs) and the gas-boilers. The input
 112 energy consists of electricity and gas, the output energy consists of electricity and thermal energy. The
 113 energy exchanges are executed through three different types of common coupling points (PCC), i.e. the
 114 electric PCC, the natural gas PCC and the heat PCC, of the IUES.

115 2.1. Natural gas network model

116 The general equation for calculating gas flow F_{kn} is shown as Eqs. (1)~(2) [27]:

$$117 F_{kn} = k_{kn} s_{kn} \sqrt{s_{kn} (p_k^2 - p_n^2)} \quad (1)$$

$$118 s_{kn} = \begin{cases} +1 & \text{if } p_k - p_n \geq 0 \\ -1 & \text{if } p_k - p_n < 0 \end{cases} \quad (2)$$

119 2.2. Energy center model

120 The energy center includes three operating modes, the electric load following mode, the thermal load
 121 following mode, and the hybrid thermal-electric load following mode [28]. In this paper, the energy
 122 conversion processes of the energy center under the hybrid thermal-electric load following mode are
 123 characterized in the energy hub model incorporating interactions among different energy systems and
 124 component constraints, as shown in Fig. 2.

Fig. 2. Structure of the energy hub model.

125 Two types of energy hub structure are considered in this paper as shown in Fig. 2. The first type is
 126 composed of a power transformer, an aggregated CHP units group and an aggregated CACs group
 127 (which are utilized to provide adequate capacity for energy supply of electric/thermal loads and hereafter
 128 referred as CHP unit and CAC). The input energy consists of electricity and natural gas. The output
 129 energy consists of electric and thermal loads. The coupling relationship between the input and output
 130 energy is expressed by Eq. (3). The partition coefficient v_e is used, $0 \leq v_e \leq 1$. $v_e P_e$ represents the
 131 electric power supply for electric loads, and $(1-v_e) P_e$ represents the electric power supply for CAC.

$$132 \underbrace{\begin{bmatrix} L_e^\varepsilon \\ L_h^\varepsilon \end{bmatrix}}_L = \underbrace{\begin{bmatrix} v_e & \eta_{ge}^{CHP} \\ (1-v_e)\eta^{AC} & \eta_{gh}^{CHP} \end{bmatrix}}_C \underbrace{\begin{bmatrix} P_{e,\varepsilon}^{EH} \\ P_{g,\varepsilon}^{EH} \end{bmatrix}}_P \quad (3)$$

133 The second type of energy hub is composed of a power transformer, an aggregated CHP units group
 134 and an aggregated gas-boilers group (which are utilized to provide adequate capacity for energy supply of
 135 electric/thermal loads and hereafter referred as CHP unit and gas-boiler). The coupling relationship of input
 136 and output is the same as that of the first type, while the energy conversion loop is different. The
 137 coupling relationship of input and output energy is expressed by Eq. (4).

$$138 \underbrace{\begin{bmatrix} L_e^\varepsilon \\ L_h^\varepsilon \end{bmatrix}}_L = \underbrace{\begin{bmatrix} 1 & v_g \eta_{ge}^{CHP} \\ 0 & v_g \eta_{gh}^{CHP} + (1-v_g)\eta^{GB} \end{bmatrix}}_C \underbrace{\begin{bmatrix} P_{e,\varepsilon}^{EH} \\ P_{g,\varepsilon}^{EH} \end{bmatrix}}_P \quad (4)$$

139 where $(1-v_g)P_g$ represents the natural gas supply for gas-boiler, and $v_g P_g$ represents the natural gas
 140 supply for CHP unit.

141 3. Formulation of the optimal day-ahead scheduling method (ODSM)

142 In this section, the ODSM for the IUES is given in details. The proposed ODSM schedules the
 143 active elements of the IUES over a 24-h time-period with an hourly time step. Network reconfiguration
 144 is one of the control methods for electric distribution networks that change the open/close status of

145 switchgear to change the operational topology of a network. Network Reconfiguration is used for
 146 various purposes, including loss minimization, load balancing, service restoration and reliability
 147 improvement [26]. In this paper, the hourly reconfigurable capability of the electric distribution
 148 network utilizing RCSs was considered in the ODSM to reduce the operation cost of IUES.

149 3.1. Framework of the ODSM

150 The framework of the ODSM is depicted in Fig. 3. The inputs of the ODSM are energy prices,
 151 distributed energy resources forecasting results, electric/thermal/natural gas loads forecasting results
 152 and the DRLs participation conditions. The outputs of the ODSM are the scheduling scheme of the
 153 optimized variables in the next 24 hours. The ODSM solver was implemented based on an Open
 154 Source Distribution System Simulator (OpenDSS) and MATLAB. The OpenDSS was utilized for
 155 solving the three-phase power flow [29]. The natural gas flow calculation, the energy center energy
 156 flow calculation and the optimization problem for optimal day-ahead scheduling based on a hybrid
 157 optimization algorithm (integrated GA with IPM) were implemented in MATLAB. The data exchange
 158 with MATLAB was implemented by driving the Component Object Model (COM, OpenDSSEngine.DLL)
 159 interface that is available in the OpenDSS package.

Fig. 3. The framework of the ODSM.

160 3.2. Objective Function

161 The objective function depicted in Eq. (5) is to minimize the total operation cost for day-ahead
 162 scheduling, which consists of four cost terms: 1) the cost of purchasing electric power ($C_t^e P_t^{grid}$); 2)
 163 the cost of purchasing natural gas power ($C_t^g P_t^{gas}$); 3) the cost of IUES's contracting with DRLs
 164 ($C_t^{DRL} P_{t,\delta}^{DRL}$); 4) the switching cost of RCSs ($C^{SW} N_{RCS_r}^{SW}$).

$$165 \quad \min f(\mathbf{x}, \mathbf{u}) = \min \left\{ \left(C_t^e P_t^{grid} + C_t^g P_t^{gas} + \sum_{\delta \in DRL} C_t^{DRL} P_{t,\delta}^{DRL} \right) + \sum_r C^{SW} N_{RCS_r}^{SW} \right\} \quad (5)$$

166 where \mathbf{x} and \mathbf{u} are state and control variables of the IUES, which consists of both discrete and
 167 continuous control variables as Eqs. (6) - (13).

$$168 \quad \mathbf{x} = [\mathbf{F}_e, \mathbf{F}_g, \mathbf{F}_{EH}] \quad (6)$$

$$169 \quad \mathbf{F}_e = [\mathbf{V}; \mathbf{S}] = [|V_1|, |V_2|, \dots, |V_{N_{e-bus}}|; |S_1|, |S_2|, \dots, |S_{N_{br}}|] \quad (7)$$

$$170 \quad \mathbf{F}_g = [\mathbf{p}; \mathbf{F}_n] = [|p_1|, |p_2|, \dots, |p_{N_{g-bus}}|; |F_{n,1}|, |F_{n,2}|, \dots, |F_{n,N_{pipeline}}|] \quad (8)$$

$$171 \quad \mathbf{F}_{EH} = [|P_{e,1}^{EH}|, |P_{e,2}^{EH}|, \dots, |P_{e,N_{EH}}^{EH}|; |P_{g,1}^{EH}|, |P_{g,2}^{EH}|, \dots, |P_{g,N_{EH}}^{EH}|] \quad (9)$$

$$172 \quad \mathbf{u} = \left[P_t^{grid}, P_t^{gas}, P_{t,\delta}^{DRL}, \mathbf{RCS}, \mathbf{v}_e, \mathbf{v}_g \right] \quad (10)$$

$$173 \quad \mathbf{RCS} = \left[RCS_1, RCS_2, \dots, RCS_{N_{br}} \right] \quad (11)$$

$$174 \quad \begin{cases} \mathbf{v}_e = \left[v_{e,1}, v_{e,2}, \dots, v_{e,N_{EH}-1} \right] \\ \mathbf{v}_g = \left[v_{g,1}, v_{g,2}, \dots, v_{g,N_{EH}-1} \right] \end{cases} \quad (12)$$

$$175 \quad N_{RCS_r}^{SW} = \sum_t \text{abs}(RCS_{r,t} - RCS_{r,t-1}) \quad (13)$$

176 where \mathbf{F}_e , \mathbf{F}_g and \mathbf{F}_{EH} are state variables of the IUES, which represent the state of electric distribution
177 network, the natural gas network and the energy center respectively; $RCS_{N_{br}}$ is the RCS statuses, with
178 “1” denotes that the RCS is closed and “0” the RCS is open.

179 3.3. Constraints

180 3.3.1. Three-phase electric network constraints

$$181 \quad P_t^{grid} + \sum_{p \in PV} P_{t,p}^{PV} + \sum_{w \in WT} P_{t,w}^{WT} + \sum_{\delta \in RL} P_{t,\delta}^{DRL} - \sum_{\varepsilon \in EH} P_{e,t,\varepsilon}^{EH} \\ - \sum_{l \in L} P_{e,t}^l - \sum_{\substack{f_g \in N_{br} \\ j \in N_{e-bus}}} P_{t,ij}^{f_g} (V_i, V_j, Y_{ij}, \theta_{ij}) = 0 \quad (14)$$

$$182 \quad P_{t,\min}^{grid} \leq P_t^{grid} \leq P_{t,\max}^{grid} \quad (15)$$

$$183 \quad \begin{cases} V_{\min} \leq V_i^a \leq V_{\max} \\ V_{\min} \leq V_i^b \leq V_{\max} \\ V_{\min} \leq V_i^c \leq V_{\max} \end{cases} \quad (16)$$

$$184 \quad 0 \leq P_{t,\delta}^{DRL} \leq P_{t,\delta,\max}^{DRL} \quad (17)$$

$$185 \quad 0 \leq i_{t,ij}^{f_g} \leq i_{ij,\max}^{f_g} \quad (18)$$

$$186 \quad N_{loop} = N_{br} - N_{e-bus} + 1 \quad (19)$$

187 Eq. (17) is the constraints constraint for DRL. Eq. (19) is established to guarantee that the electric
188 distribution network has a radial structure.

189 3.3.2. Natural gas network constraints

$$190 \quad P_t^{gas} - \sum_{\varepsilon \in EH} P_{g,t,\varepsilon}^{EH} - \sum_{\substack{f_g \in N_{g-bus} \\ n \in N_{pipeline}}} F_{t,kn}^{f_g} (p_k, p_n) = 0 \quad (20)$$

$$191 \quad P_{t,\min}^{gas} \leq P_t^{gas} \leq P_{t,\max}^{gas} \quad (21)$$

$$192 \quad p_{\min} \leq p_n \leq p_{\max} \quad (22)$$

$$193 \quad k_{cp}^{\min} \leq k_{cp} \leq k_{cp}^{\max} \quad (23)$$

3.3.3. Energy center constraints

$$\mathbf{L}^{EH} - \mathbf{C}^{EH} \mathbf{P}^{EH} = \mathbf{0} \quad (24)$$

where \mathbf{P}^{EH} is energy center energy power input vector; \mathbf{L}^{EH} is energy center energy power output vector; \mathbf{C}^{EH} is energy conversion matrix. The concrete energy center equality constraints are illustrated in Eq. (3) and Eq. (4).

Considering component capacities (illustrated in Eq. (25)) of the energy centers, the constraints of the exchange power between the energy centers and energy networks $P_{e,t,\varepsilon}^{EH}$ and $P_{g,t,\varepsilon}^{EH}$ are defined as Eq. (26).

$$\begin{cases} P_{\varepsilon,\min}^{\text{CHP}} \leq P_{\varepsilon}^{\text{CHP}} \leq P_{\varepsilon,\max}^{\text{CHP}} \\ P_{\varepsilon,\min}^{\text{AC}} \leq P_{\varepsilon}^{\text{AC}} \leq P_{\varepsilon,\max}^{\text{AC}} \end{cases} \quad (25)$$

$$\begin{cases} P_{e,t,\varepsilon,\min}^{EH} \leq P_{e,t,\varepsilon}^{EH} \leq P_{e,t,\varepsilon,\max}^{EH} \\ P_{g,t,\varepsilon,\min}^{EH} \leq P_{g,t,\varepsilon}^{EH} \leq P_{g,t,\varepsilon,\max}^{EH} \end{cases} \quad (26)$$

For the two types of energy centers, different upper and lower boundaries are illustrated in Eq. (27) and Eq. (28), respectively.

$$\text{(Type--- I)} \begin{cases} \text{(Electricity)} \begin{cases} P_{e,t,\varepsilon,\min}^{EH} = L_{e,t}^{\varepsilon} - P_{\varepsilon,\max}^{\text{CHP}} \\ P_{e,t,\varepsilon,\max}^{EH} = L_{e,t}^{\varepsilon} + P_{\varepsilon,\max}^{\text{AC}} / \eta^{\text{AC}} \end{cases} \\ \text{(Gas)} \begin{cases} P_{g,t,\varepsilon,\min}^{EH} = 0 \\ P_{g,t,\varepsilon,\max}^{EH} = P_{\varepsilon,\max}^{\text{CHP}} / \eta_{ge}^{\text{CHP}} \end{cases} \end{cases} \quad (27)$$

$$\text{(Type--- II)} \begin{cases} \text{(Electricity)} \begin{cases} P_{e,t,\varepsilon,\min}^{EH} = L_{e,t}^{\varepsilon} - P_{\varepsilon,\max}^{\text{CHP}} \\ P_{e,t,\varepsilon,\max}^{EH} = L_{e,t}^{\varepsilon} \end{cases} \\ \text{(Gas)} \begin{cases} P_{g,t,\varepsilon,\min}^{EH} = L_{h,t}^{\varepsilon} / \eta^{\text{GB}} \\ P_{g,t,\varepsilon,\max}^{EH} = P_{\varepsilon,\max}^{\text{CHP}} / \eta_{ge}^{\text{CHP}} + (L_{h,t}^{\varepsilon} - P_{\varepsilon,\max}^{\text{CHP}}) * \frac{\eta_{gh}^{\text{CHP}}}{\eta_{ge}^{\text{CHP}}} / \eta^{\text{GB}} \end{cases} \end{cases} \quad (28)$$

3.3.4. Solution

A hybrid optimization method, integrating GA with a nonlinear IPM, was employed to solve the above mixed-integer and nonlinear constraint ODSM problem [30]. The flow chart of the hybrid optimization method is shown in Fig.4.

Fig. 4. Flowchart of solving the ODSM based on the hybrid method.

The optimization problem is decomposed into two sub-problems. The first one is the continuous optimization sub-problem and is solved by the IPM, where the discrete control variables (**RCS**) are kept constant. The second one is the discrete optimization sub-problem and is solved by GA, where the

215 continuous control variables ($P_t^{grid}, P_t^{gas}, P_{t,\delta}^{DRL}, \mathbf{v}_e, \mathbf{v}_g$) are kept constant. The steps of solving ODSM
 216 based on the hybrid method are given as follows:

217 **Step 1)** Initialize the IUES, including energy center initialization, electric distribution network
 218 initialization and natural gas network initialization, based on the system structure and the input data;

219 **Step 2)** Separate the discrete control variables and continuous control variables; Generate the initial
 220 population of GA based on the input data and set iteration count $k=1$ for GA;

221 **Step 3)** Solving the continuous optimization sub-problem using the IPM with the discrete control
 222 variables (**RCS**) constant; Check the constraints and ensure all initial individuals satisfy the operating
 223 constraints; An individual is a solution for the ODSM encoded as a string, called chromosome in GA
 224 and every chromosome defines a unique scheduling solution of the IUES.

225 **Step 4)** Assess an individual based on the fitness calculation: If the iterations satisfy the stopping
 226 criteria, then go to **Step 6)**; Otherwise, set $k=k+1$ and go to **Step 5)**;

227 **Step 5)** Produce the offspring generation by solving the discrete optimization sub-problem using GA
 228 keeping the obtained continuous control variables ($P_t^{grid}, P_t^{gas}, P_{t,\delta}^{DRL}, \mathbf{v}_e, \mathbf{v}_g$) in the continuous
 229 optimization sub-problem constant; Check the radiation of the electric distribution network and ensure
 230 all individuals satisfy the operating constraints and go to **Step 3)**;

231 **Step 6)** Obtain the optimal day-ahead scheduling results for the IUES and the corresponding set-
 232 points of control variables for all participants.

233 The algorithm is stopped if one of the following stopping criteria is satisfied:

- 234 1) The number of iterations exceeds its limit (maximum number of iterations is set to be 150);
 235 2) The optimal individual keeps unchanged within 10 iterations.

236 4. Case studies

237 4.1. Case Study

238 An IUES test case in Fig. 5 was utilized to verify the effectiveness of the developed ODSM. The
 239 day-ahead scaled wholesale market prices of electricity and forecasted load on January 16, 2015 at
 240 NYISOs NPX were utilized to assess the proposed scheduling method [31]. The natural gas price was
 241 42.5\$/MWh¹ taken from PG&E [32]. The energy prices are shown in Fig. 6 and the forecasted day-
 242 ahead electric load is shown in Fig. 7 [10].

243

¹ In order to study the natural gas power and electric power in a unified scale, the unit of natural gas price is converted from \$/therm to \$/MWh (1therm=29.32kWh).

Fig. 5. Scheme of the IUES case.

Fig. 6. Day-ahead market energy price.

Fig. 7. Forecasted day-ahead electric load.

244

245 The IUES investigated in this paper consists of three parts:

246 **Part 1) (Electric distribution network):** An typical IEEE 33-bus 12.66 kV radial distribution
 247 system (including 5 tie-lines and 32 sectionalizing-lines, equipped with RCSs on each feeder) was
 248 used, and the bus voltage is subject to the constraint of $0.95 \leq V_i^{a,b,c} \leq 1.05$ [33]. Three wind turbines
 249 (forecasted hourly power generation is shown in Fig. 8) were included in the network at nodes 14, 16
 250 (A-phase grid-connected), and 31 (B-phase grid-connected). Also, three photovoltaic panels
 251 (forecasted hourly power generation is shown in Fig. 9) were connected to the electric power network
 252 at nodes 19, 27 (A-phase grid-connected), and 32 (C-phase grid-connected). Five controllable loads at
 253 nodes 8, 14, 24, 30, and 32 were considered as DRLs. The controllable loads can be decreased up to 20%
 254 as the contracts constraints for DRLs. The price for 1 MW decrease by DRLs was \$90. Also, the cost
 255 for each switching action was \$1 [10].

Fig. 8. Forecasted hourly power generation by WTs.

Fig. 9. Forecasted hourly solar radiation.

256 **Part 2) (Natural gas network):** A modified 7-node natural gas network is used here [25], which
 257 was initially designed for line-pack studies. And the natural gas network data is shown in Tab. A1. The
 258 upper and lower limits of the natural gas pipeline pressure are $\pi_{min} = 0.2$ (p.u.) and $\pi_{max} = 1.3$ (p.u.)
 259 respectively. The natural gas node GB1 is the gas resource node with a constant gas pressure 400kPa.

260 **Part 3) (Energy centers):** Four energy centers were plugged to the electric buses 8, 13, 16, 33 in the
 261 electric network and the natural gas nodes GB3, GB4, GB6, GB7 in the natural gas network. Energy
 262 center 1 and energy center 4 are set to be the type I of energy hub (depicted in Fig. 2(a)) and energy
 263 center 2 and energy center 3 are set to be the type II of energy hub (depicted in Fig. 2(b)). The energy
 264 center component capacities are given in Tab. A2. The electric/thermal loads of the four energy centers
 265 in a whole day are shown in Fig. 10.

Fig. 10. The electric/thermal loads of energy centers in a whole day.

266 4.2. Simulation results

267 Two comparative cases are presented to illustrate the effectiveness of the proposed ODSM.

268 **Case 1):** Optimal day-ahead scheduling without electric distribution network reconfiguration, i.e.,
269 seeking the optimal day-ahead scheduling solutions through controlling the electricity purchases,
270 natural gas purchases and DRL participations, without changing the topology of the electric
271 distribution network.

272 **Case 2):** Optimal day-ahead scheduling with reconfigurable topology of the electric distribution
273 network, i.e., optimally scheduling all the active elements of the IUES including the hourly electric
274 distribution network reconfiguration capability, the electricity purchases, the natural gas purchases and
275 the DRL participations, seeking to minimize the day-ahead total operation cost.

276 The optimal day-ahead scheduling scheme of the power purchases for Case 1 and Case 2 are shown
277 in Fig. 11. For the time periods including 1 to 6, 12 to 16 and 23 to 24, as the electricity purchase price
278 is lower than that of other periods, the IUES tends to purchase more electric power and less natural gas
279 power in both Case 1 and Case 2. For these time periods including 7 to 9 and 17 to 22, as the electricity
280 purchase price is higher than that of other hours, the IUES tends to purchase more natural gas power
281 and less electric power in both Case 1 and Case 2.

Fig. 11. Power purchase from energy utilities.

282 Compared with Case 1, the advantages of Case 2 including electric distribution network
283 reconfiguration lie in two aspects:

284 1) The voltage profile for the worst bus has been improved in the whole day by adjusting the statuses
285 of RCSs in Case 2 as shown in Fig. 12. This reason is that electric distribution network reconfiguration
286 can transfer loads from heavily loaded feeders to lightly loaded ones contributing voltage profile
287 improvement. Actually, the low voltage is an important factor causing decrease of power supply
288 capability.

Fig. 12. Worst bus voltage magnitudes.

289 2) For the time periods including 1 to 6, 12 to 16 and 23 to 24, by adjusting the statuses of RCSs in
290 Case 2, the reconfiguration of the electric distribution network topology enables IUES to purchase
291 more electric power at lower electric prices and contributes to more economic savings benefitted from
292 the electric power supply capability enhancement and optimized electric power flows through network
293 reconfiguration. The power supply capability enhancement is due to the voltage profile improvement
294 and optimized electric power flows through network reconfiguration, e.g. the violated bus voltage
295 constraints are removed in the load peak hours (between 8 and 21), as shown in Fig. 12.

296 The electric power purchase and the natural gas power purchase in Case 1 and Case 2 are shown in
297 Fig. 13 and Fig. 14 respectively. The imported electric power has increased and consequently the
298 imported natural gas power has decreased by adjusting the statuses of RCSs in Case 2. This is because

299 in order to minimize the operation cost, the IUES tends to purchase more electricity and minimize the
300 natural gas power purchase with the energy price conditions depicted in Fig 6.

Fig. 13. Electric power purchase.

Fig. 14. Natural gas power purchase.

301 The optimal day-ahead schedules of the four energy centers are shown in Fig. 15. It can be seen that
302 all the energy centers consume electric power (the positive value of electric power represents power
303 consumption, and the negative value of electric power represents power generation) and natural gas
304 power to satisfy the electric/thermal loads within the power regulation constraints (depicted by the
305 black dotted lines in Fig. 15).

Fig. 15. The optimal day-ahead schedule of energy centers.

306 1) Energy center 1

307 For the time periods including 1 to 6, 12 to 16 and 23 to 24, as the electricity purchase price is lower
308 than that of other time periods, the energy center 1 tends to consume more electric power (close to the
309 upper electric power regulation boundary) and less natural gas power (close to the lower natural gas
310 power regulation boundary) in both Case 1 and Case 2. In Case 1, due to the bus voltage constraint, the
311 required electric power cannot be imported from the substation and the required electric power cannot
312 be consumed by the energy center. Compared with Case 1, the electric power supply capability is
313 improved and the violated bus voltage constraint is also removed in Case 2 through changing the
314 network topology, which has resulted in more electric power consumption.

315 For the time periods 7 to 9 and 17 to 22, as the electricity purchase price is higher than that of other
316 time periods, the energy center 1 tends to consume more natural gas power and less electric power in
317 both Case 1 and Case 2. It is worth noting that energy center 1 tends to consume more natural gas
318 power to generate electric power and inject the extra electric power back into the electric network in
319 the time period 7 to 9, as shown in Fig. 15(a). There are two main reasons for this phenomenon. Firstly,
320 the electricity purchase price is higher in the time period 7 to 9, and the energy center 1 tends to
321 consume less electric power for cost saving. Secondly, the energy center 1 has more thermal load and
322 relatively less electric load (high heat to power ratio of energy center loads [34]) in time period 7 to 9
323 (depicted in Fig. 10 (a)), which matches the relative high heat to power ratio of the CHP unit [35] (set
324 to be 1.43) closely. Therefore, most of the natural gas is utilized by the CHP unit in the time period 7 to
325 9 for cost saving and the extra electric power generated by the CHP unit is injected back into electric
326 network to reduce the operation cost.

327 2) Energy center 2

328 Energy center 2 tends to consume more electric power and less natural gas power in time periods 1
329 to 9, 15 to 17 and 20 to 24 in both Case 1 and Case 2, as shown in Fig. 15(b). The reason is that the
330 primary energy efficiency of CAC for generating heat [36] is higher than that of the CHP unit for
331 generating electricity and heat [37]. Therefore, almost all the thermal loads are satisfied by CAC and
332 most of the electric loads are supplied by the electric distribution network, in despite of the high
333 electricity purchase prices in the time periods including 7 to 9 and 20 to 22. In Case 1, due to the bus
334 voltage constraint, the required electric power cannot be consumed by energy center 2, which results in
335 more natural gas power consumption in the time periods 10 to 14 and 19 to 22. Compared with Case 1,
336 by adjusting the statuses of RCSs in Case 2, the electric power supply capability is improved and the
337 violated bus voltage constraint are removed through reconfiguring the network topology, which has
338 resulted in more electric power consumption and almost no natural gas power consumption. As Fig.
339 15(b) shows, energy center 2 consumes natural gas power only in hour 18 in Case 2, which is due to
340 the highest electricity price at hour 18.

341 Comparing the power schedule results of energy center 2 with energy center 1, different components
342 characteristics (different primary energy efficiency of the energy center components) and different
343 energy center load conditions (heat to power ratio of energy center loads) can lead to different power
344 schedule results. And the optimal schedule results of energy center 2 are mainly determined by the
345 energy market price and the electric power supply capability of the electric distribution network.

346 **3) Energy center 3**

347 The schedule of energy center 3 is similar to that of energy center 2 due to the same energy center
348 components characteristics and similar load condition.

349 **4) Energy center 4**

350 The schedule of energy center 4 is similar to that of energy center 1 due to the same energy center
351 components characteristics. It is worth noting that, different from energy center 1, energy center 4
352 tends to consume more natural gas power in Case 1 while less natural gas power in Case 2 in time
353 periods 17 to 21. The reason is that the energy center 4 has more electric loads and less thermal loads
354 than that of energy center 1 in time period 17 to 21 (low heat to power ratio of energy center loads).
355 Therefore, the load condition fails to match the heat to power ratio of the CHP unit and the extra heat
356 generated by the CHP unit must be shed (the extra heat power cannot be injected back to the utility like
357 the electric power), which has poor economic efficiency. Consequently, more electric power should be
358 consumed to satisfy the energy loads and reduce the operation cost, in despite of the high electricity
359 purchase price in the time periods 17 to 21. However, the bus voltage violation occurs in Case 1 in time
360 periods 17 to 21, leading to no more electric power could be consumed and more natural gas power
361 must be consumed to cover the energy center loads. The electric bus voltage magnitude in hour 19 for

362 Case 1 and Case 2 are shown in Fig. 16. Compared with Case 1, the violated bus voltage constraint is
363 removed through reconfiguring the network topology in Case 2, which enables the energy center 4
364 consume more electric power and less natural gas power to reduce the operation cost.

Fig. 16. Electric bus voltage magnitude in hour 19.

365 It was found that the optimal schedule results of energy centers change with the energy market prices,
366 energy center loads and energy center components characteristics.

367 Fig. 17 shows the electric power reduction by DRLs in the optimal day-ahead scheduling. The total
368 electric power reduction by DRLs follows the day-ahead scaled wholesale market prices (more power
369 reductions in time periods 7 to 10 and 17 to 20, while less power reductions in other time periods) in
370 both cases and subject to the DRLs contract constraints at the same time. Compared with Case 1, the
371 scheduling process in Case 2 has less power reductions by DRLs at the most time periods in a whole
372 day, which contributes to higher comfort level of demand side.

Fig. 17. The optimal day-ahead schedule of DRLs.

373 The natural gas pipeline node pressures of the 7-node natural gas network in the whole schedule day
374 are shown in Fig. 18. The simulation results show that natural gas pipeline pressure can satisfy the
375 pressure boundaries in both cases, which guarantees the reliable operation of the natural gas network.

Fig. 18. Node pressure of the natural gas network.

376 Tab. 1 demonstrates the optimal hourly operation cost of the IUES in both cases. It is found that the
377 operation cost reductions at all hours in the whole day were achieved through the hourly electric
378 distribution network reconfiguration.

Tab. 1. Optimal day-ahead operation cost comparison.

379 5. Conclusion

380 An ODSM for the IUES considering the reconfigurable capability of electric distribution networks
381 was developed. The main contributions of this paper are summarized as follows:

382 1) An ODSM was developed to provide the IUES with economical day-ahead scheduling schemes
383 and reduce the operation cost of the IUES;

384 2) The constraints of the electric distribution network, the natural gas network and the coupled
385 constraints between the two energy systems are considered in ODSM to coordinate thermal, gas, and
386 electric energy systems in the IUES day-ahead scheduling;

387 3) The flexible electric distribution network topologies are considered in the ODSM making a good
388 use of the active network elements (e.g. the electric distribution network with the hourly reconfigurable
389 topology) of the IUES.

390 Compared with optimal scheduling excluding RCSs, considering RCSs in scheduling of the IUES
391 has benefits in electric power supply capacity improvement (enables the IUES to purchase more
392 electric power from the wholesale market at lower electricity prices), better power quality (the worst
393 bus voltage magnitude has improved through electric distribution network reconfiguration) and higher
394 comfort level of energy demand side (lower dispatch of DRLs). Meanwhile, implementation of hourly
395 flexible topologies has an improvement in economic efficiency of the IUES. Numerical studies show
396 that the proposed ODSM made a good use of the active elements of the IUES, which coordinated
397 different energy systems and guaranteed the economic operation of the IUES.

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404 **Appendix A.**

Tab. A1. Natural gas network data.

Tab. A2. Energy center component capacities.

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