IET Generation, Transmission & Distribution

Research Article

IET Journals
The Institution of Engineering and Technology

Optimal planning of energy hubs in interconnected energy systems: a case study for natural gas and electricity

ISSN 1751-8687
Received on 13th June 2014
Accepted on 2nd November 2014
doi: 10.1049/iet-gtd.2014.0607
www.ietdl.org

Mohammad Salimi, Hassan Ghasemi ✉, Mohammad Adelpour, Sadegh Vaez-ZAdeh

School of Electrical and Computer Engineering, University of Tehran, Tehran, Iran
✉ *E-mail: h.ghasemi@ut.ac.ir*

Abstract: In an energy hub, each energy carrier can be converted to other forms of energy to meet electricity, heating and cooling power demand in an optimal manner. In this study, a framework is presented to optimally design and size interconnected energy hubs. It considers physical constraints on natural gas and electricity networks and environmental issues. The proposed design methodology decides on which components should be allocated to each hub and in what capacity. It includes combined heat and power, boiler, absorption chiller, compression chiller, electricity storage (Li-ion battery) and heat storage. The model also considers incentive policies to install distributed generation thus reducing emissions. Furthermore, it takes energy supply reliability based on availability of components into account. This model can help with conducting studies related to planning future energy systems with interconnected energy hubs. The proposed model has been simulated on an interconnected test system, which represents a municipal district with three energy hubs.

Nomenclature

Indices

t	time (hours)
i, j, k	energy hub numbers
l	component outage scenarios
s	load scenarios 01

Series

$\mathcal{H}$	energy hubs

Constants

$\eta^{\text{ge}}_{\text{CHP}}, \eta^{\text{gh}}_{\text{CHP}}$	efficiency of gas to electricity/heat conversion in a combined heat and power (CHP)
η_{B}	efficiency of gas to heat conversion in boiler
η_{HE}	efficiency of heat exchanger
$\eta^{\text{ch}}_{\text{HS}}, \eta^{\text{dch}}_{\text{HS}}$	efficiency of charging/discharging a heat storage
η_{T}	efficiency of transformer
$\eta^{\text{ch}}_{\text{PS}}, \eta^{\text{dch}}_{\text{PS}}$	efficiency of charging/discharging a battery
γ	CO_2 emission coefficient
ω	distributed generation bonus coefficient
$\overline{G_{ij}}$	maximum natural gas flow through pipeline i, j
$\overline{P_{ij}}$	maximum electrical power flow through line i, j
ξ	tax related to carbon dioxide emission
$\text{COP}_{\text{AC/CC}}$	coefficient of performance in absorption/ compression chillers
d	discount rate
$K_{ij}, K_{\text{com},\ ij}$	constant of pipelines/compressors i, j
VOLL	value of lost load
y_{ij}	susceptance of line i, j
y_{p}	planning horizon (years)
z_{ij}	impedance of line i, j

Variables

δ	voltage angle
π	price of energy carriers
ρ	gas pressure
ACF	annual cash flow
C^{f}	annual fixed costs
C^{v}	annual variable costs
C_{EMS}	emission costs
C_{ENS}	cost of energy not supplied
C_{inv}	investment costs
CAP	component capacity
CL_{AC}	output cooling power of an absorption chiller
CL_{CC}	output cooling power of a compression chiller
$\cos\varphi$	power coefficient
DCF	daily cash flow
EENS	expected energy not supplied
ENPV	expected net present value
ENS	energy not supplied
G_{com}	natural gas consumed in compressor
G_{s}	natural gas sold to gas network
G_{ij}	natural gas flow through pipeline i, j
G_{in}	natural gas injected at the input of hub
H_{B}	output heat power of boiler
H_{in}	heat power purchased from district heat network
H_{s}	heat power sold to district heat network
H_{AC}	heat consumption of an absorption chiller
H_{CHP}	heat generation of CHP
H_{ex}	input heat power of heat exchanger
H_{is}	input heat power of heat storage
H_{os}	output heat power of heat storage
HSE	energy level of heat storage
I	integer decision variable
$L_{\text{e}}, L_{\text{c}}, L_{\text{h}}$	electrical/cooling/heating loads in hub output
NPV	net present value
P_{s}	electric power sold to grid
P_{T}	output electric power of transformer
P_{CC}	electric power consumption of compression chiller
P_{CHP}	output electric power of CHP
P_{ij}	active power flow through transmission line i, j
P_{is}	input electric power of battery
P_{in_i}	electric power purchased from the network and injected at the input of hub i
P_{os}	output electric power of battery
Pr	probability of scenarios

PSE	energy level of battery
Q_{ij}	reactive electric power flow through transmission line i, j
V	voltage
v	dispatch factor

1 Introduction

Nowadays, electricity and natural gas networks are well developed and are mainly operated independently. As one of the suggestions and as an outlook in the field of operation and management of energy systems, it is recommended to use multiple energy carriers within the context of energy hubs enabling interaction among energy carriers.

Energy hub was first presented in the Vision of Future Energy Networks project aiming at developing scenarios on how transmission and distribution systems should look like in 30–50 years considering improvement in ecology, economy and functionality [1].

In [2, 3], the fundamental concepts of energy hubs are presented along with their basic structure. In [4–9], a general overview with some examples of energy hubs is provided. In addition, hub modelling and its optimal operation scheduling are formulated along with various examples; to determine the optimal operation of an integrated system of electricity and natural gas, an optimisation problem must be solved. In [4], the use of hydrogen as an energy carrier in energy hubs has been examined. Also, the energy networks used in the energy hub have been investigated in the literature [2]. In [10], a method to estimate the heating load in an energy hub along with a demand side management is provided. Schulze *et al.* [11] modifies the model of energy hub by adding renewable energy resources. Koeppel [12] examines the reliability of hubs. In [13, 14], the impact of natural gas grid on electricity network has been investigated. Greenhouse gas emissions in different power plants have been modelled in [15]. Some studies, for example, Serra *et al.* [16] examined the concept of polygeneration and energy integration, which include goods production systems (such as sugar factory) along with energy resources. Essentials of enhancement of energy hubs are under investigation; for example, a geographical information system to evaluate integrated energy systems in urban areas has been investigated in [17].

When an energy hub is designed, it is necessary to choose the components of the hub carefully to reduce costs, increase economic efficiency and maintain satisfactory reliability. Thus, both economic and technical factors influencing hub's performance should be taken into account. For example, restrictions on electricity and natural gas networks, costs related to emissions of carbon dioxide and energy interruption costs should be carefully modelled at design stage. Furthermore, benefits such as selling surplus electricity and heat to the grid, receiving rewards for distributed electricity generation can encourage the private sector to install energy hubs and combined heat and power (CHP) systems.

The optimal size of co- and tri-generation units in a single hub has been previously investigated in several references. In [18], economic comparison between the absorption chiller and compression chiller has been studied. Owing to the benefits of natural gas such as low production of greenhouse gases, CHP technology is being deployed as one of the most popular energy conversion facilities [2]. In [19–23], determining the optimal size of a CHP unit has been investigated. Konstantakos *et al.* [24] used decision theory in the optimal sizing of CHP considering different options. The obtained size and solution may not be economically and/or technically feasible when the above-mentioned factors are included in the study.

Optimised management of a single energy hub has been studied in [25]. Optimal design of a polygeneration system within the context of smart grids has been examined in [26], considering interdependency between electrical and thermal flows. Also, Khodaei and Shahidehpour [27] studied the optimal planning of electricity generation and transmission in microgrids. Karami *et al.* [28] examined the optimal management of residential distributed energy resources, considering electricity power storage systems (batteries). Optimal operation of residential energy hubs within smart grids is explored in [29]. Fazlollahi *et al.* [30] investigated methods of optimal investment and operation of a complex energy system. However, the optimal design and sizing of energy components in a system of interconnected energy hubs considering the interdependencies among electricity, heat and natural gas networks and capability of selecting and sizing hub components has not been accurately investigated or modelled. In this paper, a model is proposed to optimally design and size a system of interconnected hubs, which provides a realistic and feasible solution since it utilises all previously mentioned economic and technical factors as well as respecting physical and reliability constraints on the energy networks.

In Section 2, a brief description of energy hubs, their model and the fundamentals of power and gas flow in electricity and natural gas networks are presented. Section 3 presents the proposed modelling framework for the optimal design and sizing of energy hubs. In addition, in this section, the objective function and its associated constraints are described. In Section 4, the proposed model is simulated on a multi-carrier energy system consisting of three interconnected energy hubs representing a municipal district. The paper is concluded in Section 5.

2 Background on energy hubs

In general, an energy hub provides the link between energy producers, consumers and energy transmission network. From a systematic viewpoint, each hub can include many different energy carriers as inputs and outputs. These carriers interact with each other using hub elements (connectors, conversion and storage facilities). An energy hub can include variety a of energy carriers such as electricity, natural gas, hydrogen, wood chips, synthetic natural gas (SGN), renewable energy sources like wind power and solar energy. Also, different technologies can be implemented within energy hubs including CHP, chillers, boiler, fuel cell, wind turbine, solar cell, heat storage, electric power storage (e.g. Li-ion battery) and pumped hydro plants. An energy hub is an environment for interaction among different energy infrastructures enabling conversion and transmission of energy carriers. The idea of energy hubs and looking to energy infrastructures (e.g. electricity, natural gas, district heating systems etc.) have several prospective advantages which include higher efficiency and better reliability.

2.1 Energy hub concept

Each hub is defined by a series of energy carriers (e.g. electricity, natural gas etc.). The size of an energy hub can vary from a hospital or hotel in a city or a country. The inputs and outputs of an energy hub can be related with a coupling matrix as defined in [2]. Fig. 1 shows an energy hub providing interaction among three energy networks and demand (electricity, gas and district heat) through direct connection, conversion facilities (power transformers, chillers, CHPs) and storage components including heat storage and electric power storage. This paper focuses on the mentioned energy carriers and technologies; however, it is good to mention that as was discussed before, an energy hub can also include other energy carriers and technologies. Other energy carriers and technologies, for example, the fuel cell can be easily added to the proposed model by adding the corresponding equations (similar to the approach used for gas and electricity in this paper) currently available in the literature.

For the energy hub illustrated in Fig. 1, the demand-supply balance equations and equations governing conversion of energy carriers and operation of storage facilities can be formulated as follows

$$L^t_{e_i} + P^t_{s_i} + P^t_{CC_i} + P_{is_i} = P^t_{T_i} + P^t_{CHP_i} + P_{os_i} \quad (1)$$

$$L^t_{h_i} + H^t_{AC_i} + H^t_{s_i} + H^t_{is_i} = H^t_{CHP_i} + H^t_{B_i} + H^t_{ex_i} + H^t_{os_i} \quad (2)$$

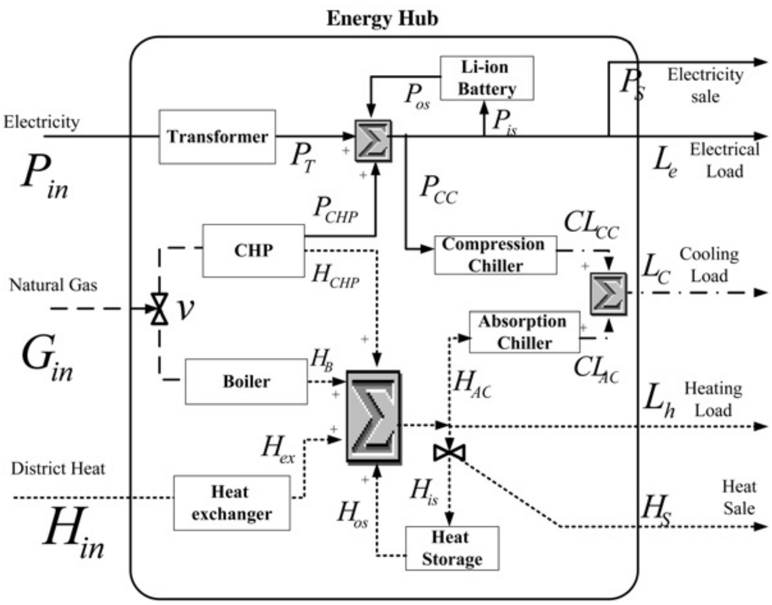

Fig. 1 *Structure of the investigated energy hub*

$$L^t_{c_i} = CL^t_{AC_i} + CL^t_{CC_i} \tag{3}$$

$$P^t_{T_i} = \eta_{T_i} P^t_{in_i} \tag{4}$$

$$P^t_{CHP_i} = \eta^{ge}_{CHP_i} v^t_i G^t_{in_i} \tag{5}$$

$$H^t_{CHP_i} = \eta^{gh}_{CHP_i} v^t_i G^t_{in_i} \tag{6}$$

$$H^t_{B_i} = \eta_{B_i} (1 - v^t_i) G^t_{in_i} \tag{7}$$

$$H^t_{ex_i} = \eta_{HE_i} H^t_{in} \tag{8}$$

$$CL^t_{AC_i} = COP_{AC_i} H^t_{AC_i} \tag{9}$$

$$CL^t_{CC_i} = COP_{CC_i} P^t_{CC_i} \tag{10}$$

$$HSE^{t+1}_i = HSE^t_i + \left[\eta^{ch}_{HS_i} H^t_{is_i} - \frac{H^t_{os_i}}{\eta^{dch}_{HS_i}} \right] \tag{11}$$

$$PSE^{t+1}_i = PSE^t_i + \left[\eta^{ch}_{PS_i} P^t_{is_i} - \frac{P^t_{os_i}}{\eta^{dch}_{PS_i}} \right] \tag{12}$$

$$0 \le v^t_i \le 1 \tag{13}$$

Equation (1) describes the demand–supply balance for electrical power within each hub. Equations (2) and (3) demonstrate the demand–supply balance for heat and cooling powers within each hub, respectively. Equations (4)–(8) relate the output power of transformer, CHP, boiler and heat exchanger to their inputs using efficiency coefficient. Equations (9) and (10) relate the cooling power of absorption chiller and compression chiller to their inputs by means of COP. Equations (11) and (12) connect the charging state of heat storage and battery to their previous state of charge, input, output and efficiencies.

One of the important parameters in an energy hub is dispatch factor, which is denoted by v^t_i. As can be seen in Fig. 1, the natural gas flow in the input of the hub (G^t_{in}) is divided into two parts: one part is consumed by the CHP and the other part feeds the boiler. The percentage share of each converter is determined by dispatch factor and is controlled by the central manager. In this paper, for chillers (absorption and compression), the coefficient of performance (COP) is used; it is a standard parameter to compare different chillers that is defined as the cooling power produced divided by the power consumed.

2.2 Energy transmission systems

Electricity and natural gas networks play key roles in energy hubs because they provide the transfer capability among energy hubs, so it is necessary to include their equations when describing these interconnected networks. Fig. 2 shows an example of interconnected energy hubs involving electricity and natural gas networks.

2.2.1 Electricity network: As shown in Fig. 2, the electric transmission lines are modelled using the π equivalent circuit. Each node in the power network is described by its voltage $|V_i|$, phase angle δ_i, injected active electric power (purchased from the network) P_{in_i} and injected reactive power Q_{in_i}. The equations representing the electricity network are as follows [2]

$$P^t_{s_i} - P^t_{in_i} = \sum_{j \in \mathcal{H}} P^t_{ij}, \quad \forall i, \quad j \in \mathcal{H} = 1, 2, \ldots, N_{\mathcal{H}} \tag{14}$$

$$V_i = |V_i| \, e^{j\delta_i} \tag{15}$$

$$P_{ij} + jQ_{ij} = V_i \left[\frac{V_i - V_j}{z_{ij}} + \frac{V_i y_{ij}}{2} \right]^* \tag{16}$$

$$Q_{in} = P_{in} \tan \varphi_i \tag{17}$$

$$-\overline{P_{G_i}} \le P^t_{ij} \le \overline{P_{G_i}} \tag{18}$$

In (16), the star denotes the conjugate.

2.2.2 Natural gas network: The natural gas network can be modelled similar to the electricity network. Fig. 2 shows the model of a gas pipeline with a compressor. Each node in the natural gas network has two parameters, the gas pressure and the injected gas flow. At each hub, there should be a balance between gas injection into the hub, gas solving to the network and gas flow through the pipeline connected to the hub, that is

$$G^t_{s_i} - G^t_{in_i} = \sum_{j \in \mathcal{H}} G^t_{ij}, \quad \forall i, \quad j \in \mathcal{H} = 1, 2, \ldots, N_{\mathcal{H}} \tag{19}$$

$$G^t_{ij} \le \bar{G}_{ij} \tag{20}$$

Owing to varying gas characteristics at different pressures, the friction coefficient varies at different pressures; however, for pressures higher

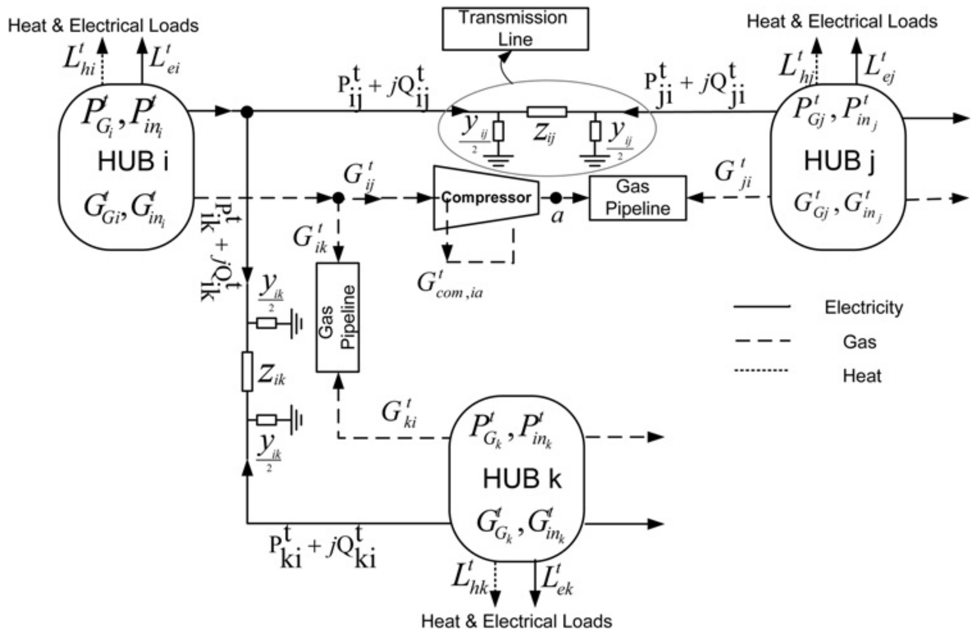

Fig. 2 *Example model of interconnected energy hubs*

than 75 kPa, usually the following equations [13, 14] can be used

$$G_{ji}^t = \sigma_{ji} K_{ij} \sqrt{\sigma_{ji}((\rho_a^t)^2 - (\rho_j^t)^2)} \tag{21}$$

$$\sigma_{ji} = \begin{pmatrix} +1, & \rho_a \geq \rho_j \\ -1, & \text{otherwise} \end{pmatrix} \tag{22}$$

Node a corresponds to the high pressure node in the compressor as shown in Fig. 2; K_{ij} is a pipeline factor that depends on parameters such as line length, pipe diameter, temperature and pressure of the environment [2]; and ρ_i is the gas pressure at Hub i.

There is a relationship between pipeline factor, length and diameter of a pipe as follows [2]

$$K_{ij} \propto \sqrt{\frac{(\text{Pipe diameter})^5}{\text{Line length}}} \tag{23}$$

The amount of consumed gas in the compressor ($G_{\text{com},ia}^t$) depends on gas pressure difference between two sides of the compressor, that is, upstream and downstream

$$\frac{G_{\text{com},ia}^t}{G_{ij}^t} = K_{\text{com},ij}(\rho_a^t - \rho_i^t); \quad 1.2 \leq \frac{\rho_a^t}{\rho_i^t} \leq 1.8 \tag{24}$$

$K_{\text{com},\ ij}$ is the compressor constant. Therefore in presence of a compressor along with a natural gas pipeline $G_{ij}^t \neq G_{ji}^t$ and

$$G_{ij}^t = G_{\text{com},ia}^t - G_{ji}^t \tag{25}$$

3 Proposed framework to design interconnected energy hubs

As mentioned before, to optimally design and size interconnected energy hubs, one must accurately model both costs and benefits of adding components to each hub as well as respecting physical and reliability constraints. Fig. 3 shows the proposed general modelling framework for optimal design and sizing of a system of interconnected energy hubs. The daily incomes include sales to subscribers, received rewards due to decentralised electricity generation and selling surplus energy (electricity and heat) to the corresponding grids. Annual costs include fixed and variable costs. Daily costs include purchase of energy from networks, penalties for energy not supplied and penalties for greenhouse gas emissions.

Installation costs are fixed costs that are initially spent if the hub designer decides to install a specific component within a hub. Therefore a binary decision variable is assigned to each available component within a hub. For component A, the decision variable I_A = ‘1’ indicates that it is added to the hub and I_A = ‘0’ means that the hub does not consist of component A.

Given the above description, the overall objective function is defined as the maximum net present value (NPV) during the planning horizon. NPV is one of the standard methods to evaluate economic projects [31]. In this method, all future incomes and expenses are converted into their present values over the planning period based on the discount rate and the year of cash flows. If the NPV of the project is positive, the plan is acceptable and profitable. The discount rate based on which the project’s NPV becomes zero is defined as the internal rate of return (IRR). Considering the above-mentioned incomes and costs in a system of interconnected energy hubs, the NPV is formulated as follows [31]

$$\text{NPV} = -C_{\text{inv}} + \sum_{y=1}^{y_p} \frac{\text{ACF}}{(1+d)^y} \tag{26}$$

$$\text{ACF} = \left[\text{DCF}_{\text{summer}} + \text{DCF}_{\text{winter}}\right] \times \frac{365}{2} - C^{\text{f}} - C^{\text{v}} \tag{27}$$

$$\text{DCF} = \text{Sale} + \text{Bonus} - \text{Purchase} - C_{\text{ENS}} - C_{\text{EMS}} \tag{28}$$

$$\text{Sale} = \sum_{i \in \mathcal{H}} \sum_{t=1}^{24} \begin{bmatrix} \pi_{\text{e}}^t (L_{\text{e}_i}^t + P_{\text{s}_i}^t) \\ + \pi_{\text{h}}^t (L_{\text{h}_i}^t + H_{\text{s}_i}^t) \\ + \pi_{\text{c}}^t (L_{\text{c}_i}^t + \text{CL}_{\text{s}_i}^t) \end{bmatrix} \tag{29}$$

$$\text{Bonus} = \omega \cdot \pi_{\text{g}}^t \sum_{i \in \mathcal{H}} \sum_{t=1}^{24} v_i^t G_{\text{in}_i}^t \tag{30}$$

$$\text{Purchase} = \sum_{i \in \mathcal{H}} \sum_{t=1}^{24} (\pi_{\text{e}}^t P_{\text{in}_i}^t + \pi_{\text{g}}^t G_{\text{in}_i}^t + \pi_{\text{h}}^t H_{\text{in}_i}^t) \tag{31}$$

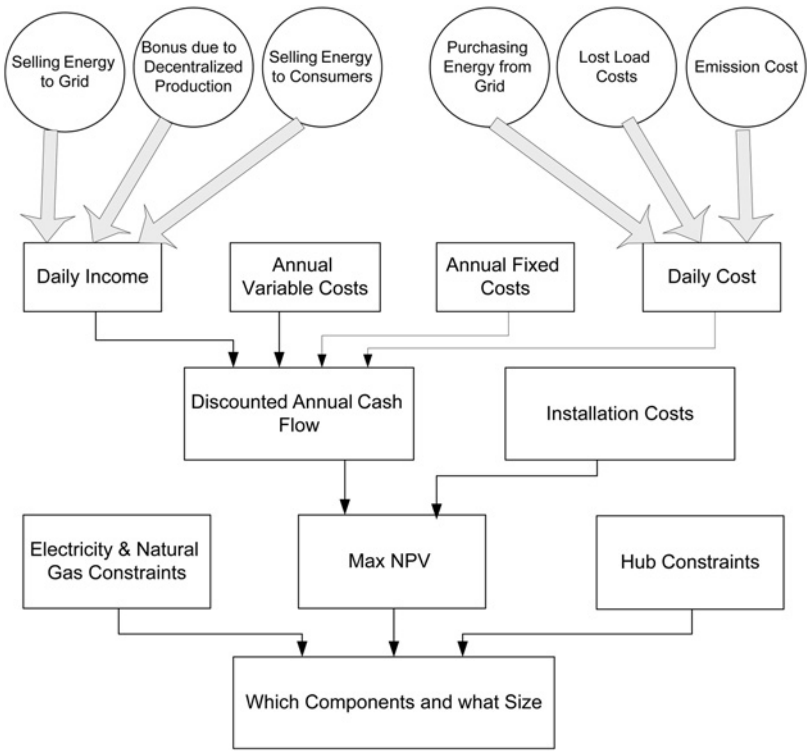

Fig. 3 *Proposed design and sizing framework diagram*

$$C^f = \sum_{i\in\mathcal{H}} \begin{bmatrix} I_{\mathrm{CHP}_i} C^f_{\mathrm{CHP}_i} + I_{B_i} C^f_{B_i} \\ + I_{\mathrm{HS}_i} C^f_{\mathrm{HS}_i} + I_{\mathrm{AC}_i} C^f_{\mathrm{AC}_i} \\ + I_{\mathrm{CC}_i} C^f_{\mathrm{CC}_i} + I_{\mathrm{PS}_i} C^f_{\mathrm{PS}_i} \end{bmatrix} \tag{32}$$

$$C^v = \sum_{i\in\mathcal{H}} \begin{bmatrix} I_{\mathrm{CHP}_i} C^v_{\mathrm{CHP}_i} \mathrm{CAP}_{\mathrm{CHP}_i} \\ + I_{B_i} C^v_{B_i} \mathrm{CAP}_{B_i} \\ + I_{\mathrm{HS}_i} C^v_{\mathrm{HS}_i} \mathrm{CAP}_{\mathrm{HS}_i} \\ + I_{\mathrm{AC}_i} C^v_{\mathrm{AC}_i} \mathrm{CAP}_{\mathrm{AC}_i} \\ + I_{\mathrm{CC}_i} C^v_{\mathrm{CC}_i} \mathrm{CAP}_{\mathrm{CC}_i} \\ + I_{\mathrm{PS}_i} C^v_{\mathrm{PS}_i} \mathrm{CAP}_{\mathrm{PS}_i} \end{bmatrix} \tag{33}$$

$$\begin{aligned} C_{\mathrm{ENS}} = {} & \mathrm{EENS_e} \cdot \mathrm{VOLL_e} \\ & + \mathrm{EENS_h} \cdot \mathrm{VOLL_h} \\ & + \mathrm{EENS_c} \cdot \mathrm{VOLL_c} \end{aligned} \tag{34}$$

$$C_{\mathrm{EMS}} = \xi \cdot \sum_{i\in\mathcal{H}} \sum_{t=1}^{24} \begin{bmatrix} \gamma_{\mathrm{CHP}} P^t_{\mathrm{CHP}_i} + \gamma_B H^t_{\mathrm{B}_i} \\ + \gamma_{\mathrm{AC}} \mathrm{CL}^t_{\mathrm{AC}_i} + \gamma_{\mathrm{CC}} \mathrm{CC}^t_i \end{bmatrix} \tag{35}$$

$$\mathrm{EENS} = \sum_l Pr(l) \mathrm{ENS}(l) \tag{36}$$

where C_{inv} is the initial cost of installing energy hubs. Annual cash flow (ACF) is defined based on daily cash flow (DCF) and annual fixed and variable costs, which include maintenance costs. DCF includes proceeds from selling energy carriers to the grid denoted here as 'sale' and the received 'bonus' as a reward because of the decentralised power generation. On the other hand, the daily costs include the 'purchase' of energy carriers from the corresponding spot markets, the costs of energy not supplied C_{ENS} and emission costs C_{EMS}.

Producing electricity in a decentralised manner using CHP has advantages such as higher efficiency and less loss in electrical transmission lines. Thus, by using CHP, natural gas consumption compared with burning it in centralised gas power plants should be lower. Therefore, as an incentive, natural gas is sold to CHP operators at a lower price.

Using variety of elements in an energy hub increases system reliability as well as the capital cost. Therefore a trade-off between reliability cost and installation cost should be done. Expected energy not supplied (EENS) index can be used to measure the level of system reliability, which is calculated here by means of value of lost load (VOLL) as defined by (34).

It should be noted that along with carbon dioxide, there might be other air pollution emissions within an energy hub, for example, NO_x and SO_x that are not considered in this study (see e.g. [16]). In this paper, two forms of carbon dioxide emissions are considered:

1. Emissions within each hub: Elements used in the energy hub, such as CHP or boiler, produce carbon dioxide during their operation. Energy hub is penalised and has to pay for these emissions; the corresponding cost is represented by C_{EMS} in (28).
2. Emissions outside the hubs: Depending on the grid emission factor, network losses and generation portfolio, which are different for different countries, electricity generation using CHP may produce less emission compared to conventional power plants. In this case, the authors suggest that in order to encourage installing CHPs and hence producing electricity in a decentralised manner, energy prices in the spot markets should be modified by introducing taxes as follows

$$\pi_{\mathrm{e}}^{\mathrm{new}} = \pi_{\mathrm{e}}^{\mathrm{old}} + \xi \cdot \gamma_{\mathrm{e}} \tag{37}$$

$$\pi_{\mathrm{g}}^{\mathrm{new}} = \pi_{\mathrm{g}}^{\mathrm{old}} + \xi \cdot \gamma_{\mathrm{g}} \tag{38}$$

4 Test case

As a case study, optimum design and sizing of three interconnected energy hubs representing a municipal district is examined here as shown in Fig. 4. Each hub's structure is similar to that of the represented by Fig. 1. To solve the formulated optimisation problem, fmincon.m from the Matlab optimisation toolbox which is software for non-linear programming has been used.

Discount rate and project lifetime has been chosen 8% and 15 years, respectively. Table 1 shows the assumed CO_2 emission coefficients for each component within a hub. Heating and cooling

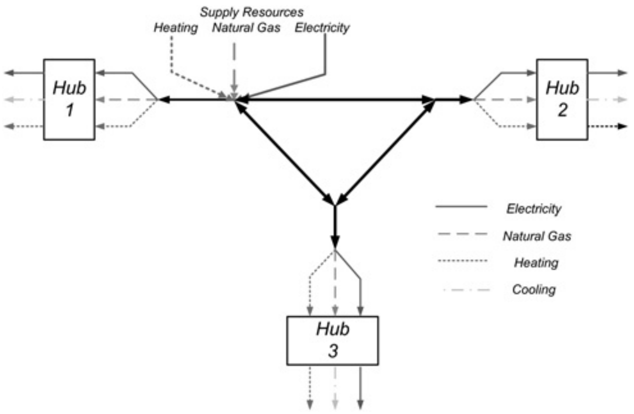

Fig. 4 *Municipal district/town with three energy hubs*

Table 1 CO_2 emissions coefficients [15, 32]

	γ_{CC}	γ_{CA}	γ_{B}	γ_{CHP}	γ_{g}	γ_{e}
CO_2 emission, kg/MWh	439	148	123	367	50	444

prices are assumed to be

$$\pi_h = \frac{\pi_g}{\eta_B} \tag{39}$$

$$\pi_c = 1.6\pi_h \tag{40}$$

In Table 2, the price of electricity and gas and the maximum capacity of selling electricity and heat to the grid are given. Selling electricity capacity to the grid during off-peak hours is considered zero; the power grid during off-peak does not need to acquire an additional power provided by hubs, thus, the assumption is reasonable. Also, during on-peak hours, sale capacity to the grid is assumed to be double the amount of mid-peak hours. These values are assumed

Table 2 Prices and energy sale capacity during the day

Time	Off-peak	Mid-peak	On-peak
electricity price, ¢/kWh	8	12	15
capacity of electricity sale to grid, kW	0	150	300
natural gas price, ¢/kWh	3	3	3
capacity of heating sale to grid, kW	400	400	400

Table 3 Components specifications within hubs

	Efficiency or COP	Availability, %	Annual variable costs, $/kW	Annual fixed costs, $
CHP	$\eta_{CHP}^{ge} = 0.35$ $\eta_{CHP}^{gh} = 0.35$	95	131	20 000
boiler	$\eta_B = 0.75$	97	80	10 000
compression chiller	$COP_{CC} = 4$	98	115	15 000
absorption chiller	$COP_{AC} = 1.2$	98	93	15 000
heat storage	$\eta_{HS}^{ch} = 0.95$ $\eta_{HS}^{dch} = 0.95$	98	100	8000
transformer	$\eta_T = 0.98$	99.9	—	—
heat exchanger	$\eta_{HE} = 0.9$	99.9	—	—
Li-ion battery	$\eta_{PS}^{ch} = 0.88$ $\eta_{PS}^{dch} = 0.98$	98	180	10 000

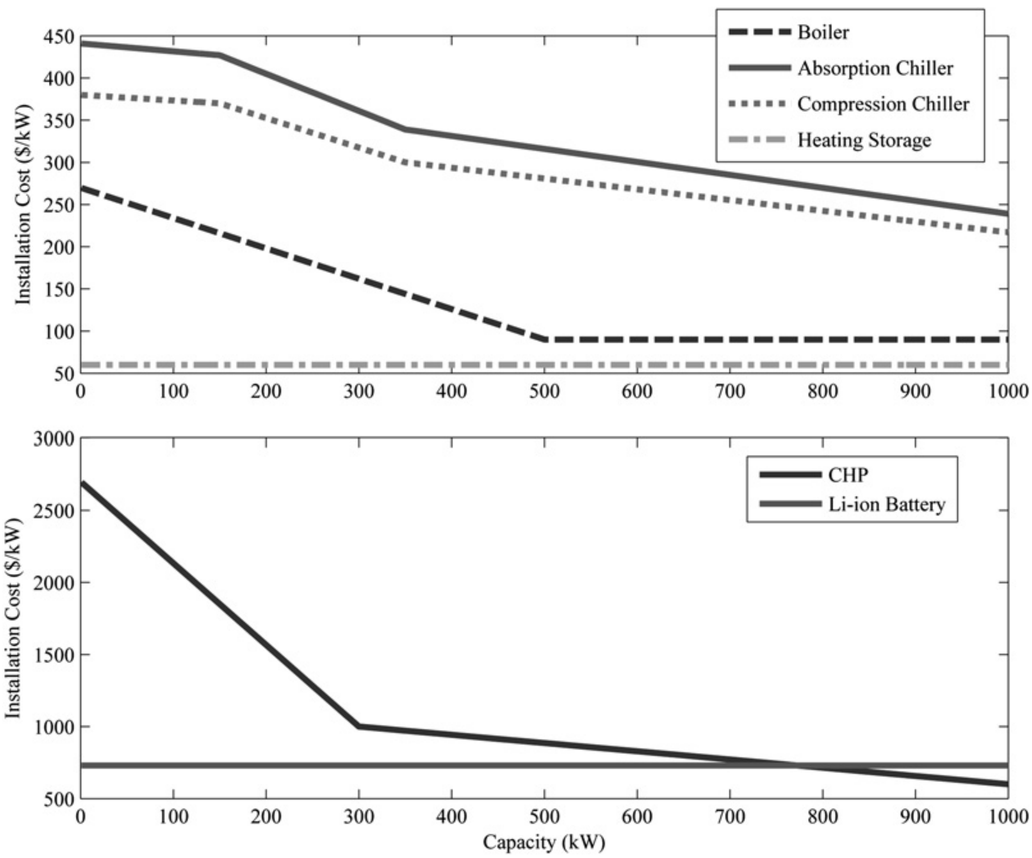

Fig. 5 *Installation cost of boiler, absorption chiller, compression chiller, heating storage, Li-ion battery and CHP as functions of their capacities [2, 32, 33]*

Table 4 Networks parameters

Line	Transmission lines and pipelines data		
	z	y	K
1 and 2	0.9 + j2.7 pu	j1.05 × 10^{-7} pu	160
1–3	0.6 + j1.8 pu	j0.75 × 10^{-7} pu	145
2 and 3	0.3 + j1.2 pu	j0.45 × 10^{-7} pu	120
Supply limitations			
Supply		Max, kW	
natural gas		6500	
electric power		2500	
Network limitations			
pressure		380 < ρ_i < 460 kPa	
voltage		0.9 < V_i < 1.1 pu	

to be identical for all three hubs. In this paper, as another assumption, cooling power cannot be sold to the grid.

Table 3 shows the efficiency, variable costs, fixed annual cost and availability of the energy hub components. Fig. 5 depicts installation costs as function of capacity for individual components such as boiler and chiller. The parameters of electricity and gas networks are given in Table 4. The base electrical power is assumed 500 kVA. Fig. 6 shows forecast curves for electrical, heating and cooling daily loads. In order to observe the restrictions of the electricity and natural gas networks on simulation results, predicted loads are assumed to be similar for all the three hubs. Power factor for all the hubs is assumed to be 0.9. In this study, the numerical value of ω is considered to be 0.75. Also, the penalty factor of lost loads is assumed to be 30 times the price of energy carriers.

District heat networks have been developed in some countries, while such a network does not exist in most countries yet. Two different cases are considered and the results are presented for each case (Table 5 and Figs. 7–11). Besides NPV, discounted payback period (DPP) is shown for each case showing the time period required to recover the investment; note that the DPP should be less than the project life.

Table 5 Economic assessment results for Cases A and B

Cases	NPV, M$	DPP, years	IRR, %
A	5.13	2	42
B	2.06	5	22

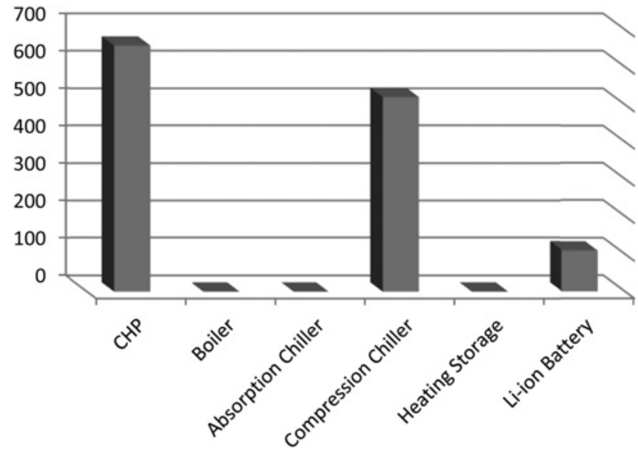

Fig. 7 *Optimal capacity of hub's components (kW); Case A*

4.1 Case A: with district heating network

In this case, it is assumed that a heating network exists. The obtained results demonstrate that when heating network exists, boiler, absorption chiller and heat storage should not be installed. In fact, in this case, the heat required in each hub is supplied by a district heat network and it is not cost effective for the hubs to install any boilers or heat storages. Also, it is more efficient to utilise compression chillers; this is due to the fact that when an

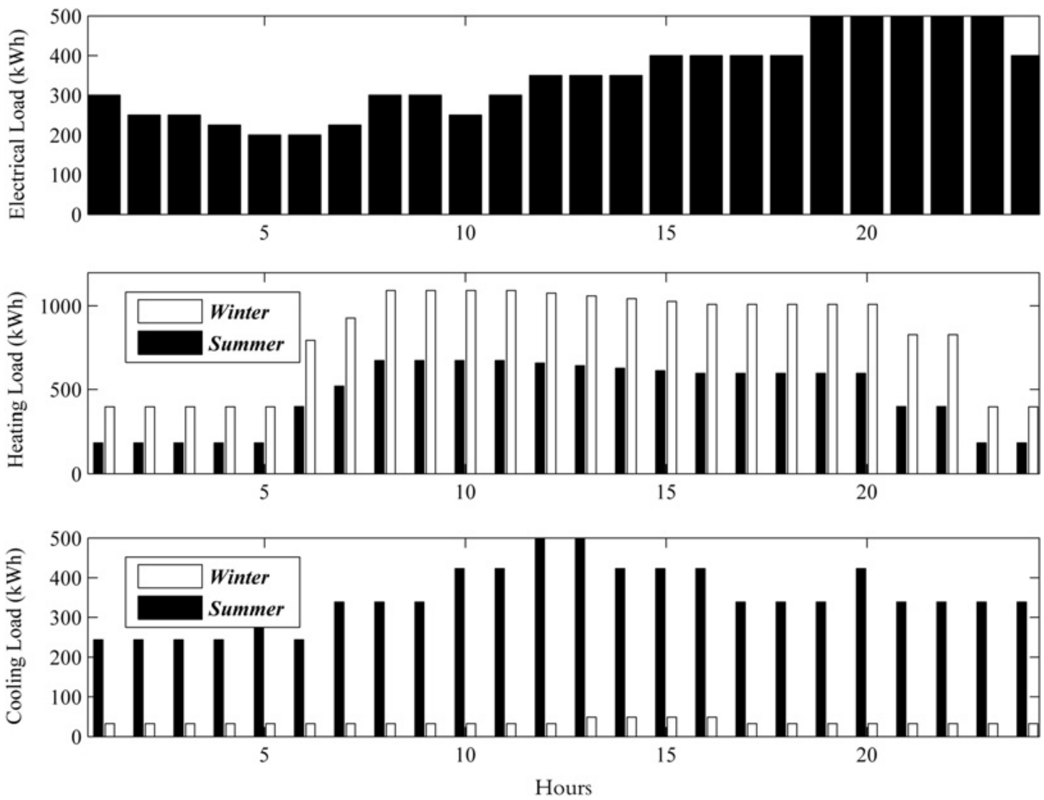

Fig. 6 *Consumption curves during typical days of summer and winter*

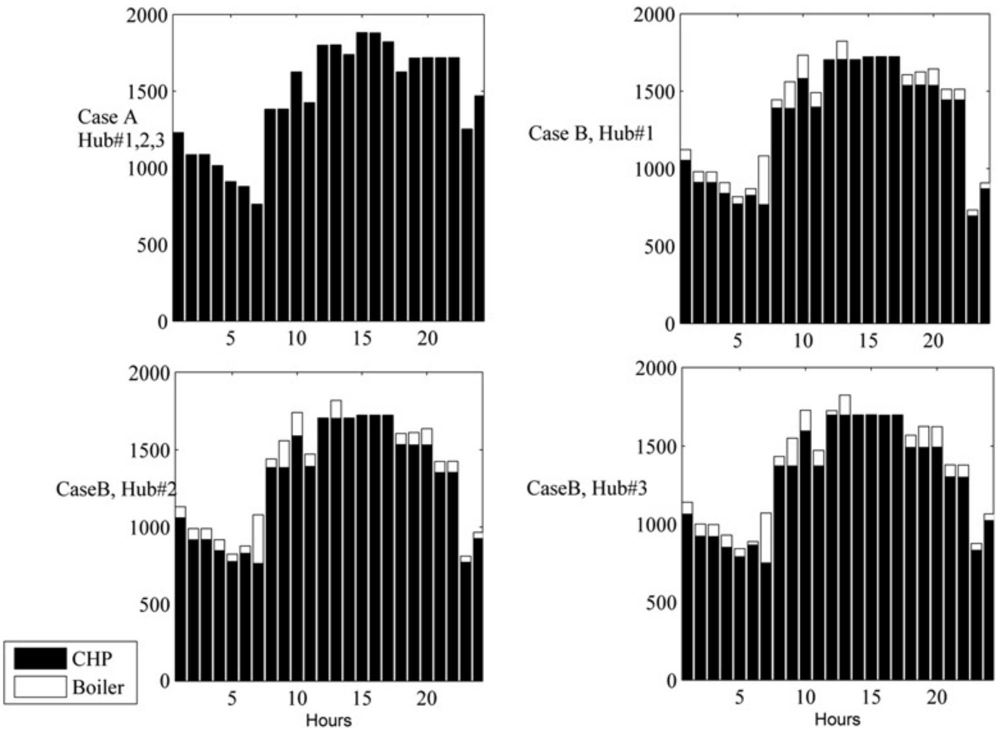

Fig. 8 *Natural gas (kWh) consumption in the CHP and boiler during a typical summer day*

absorption chiller is used, a boiler must also be installed to generate the heat required by the absorption chiller thus increasing the cost. In this case, CHP is more efficient to generate electricity compared to purchasing power from the grid. As shown in the upper part of Figs. 8 and 9, the CHP will work during the day to meet electricity demand thus following consumption patterns. The CHP utilisation pattern is similar in summer and winter. In this case, system constraints are not binding and hence they do not cause any differences among the three hubs in the way they operate.

4.2 Case B: without district heating network

In this case, there is no possibility to sell or buy heating power and hence heating power demand should be generated within each hub.

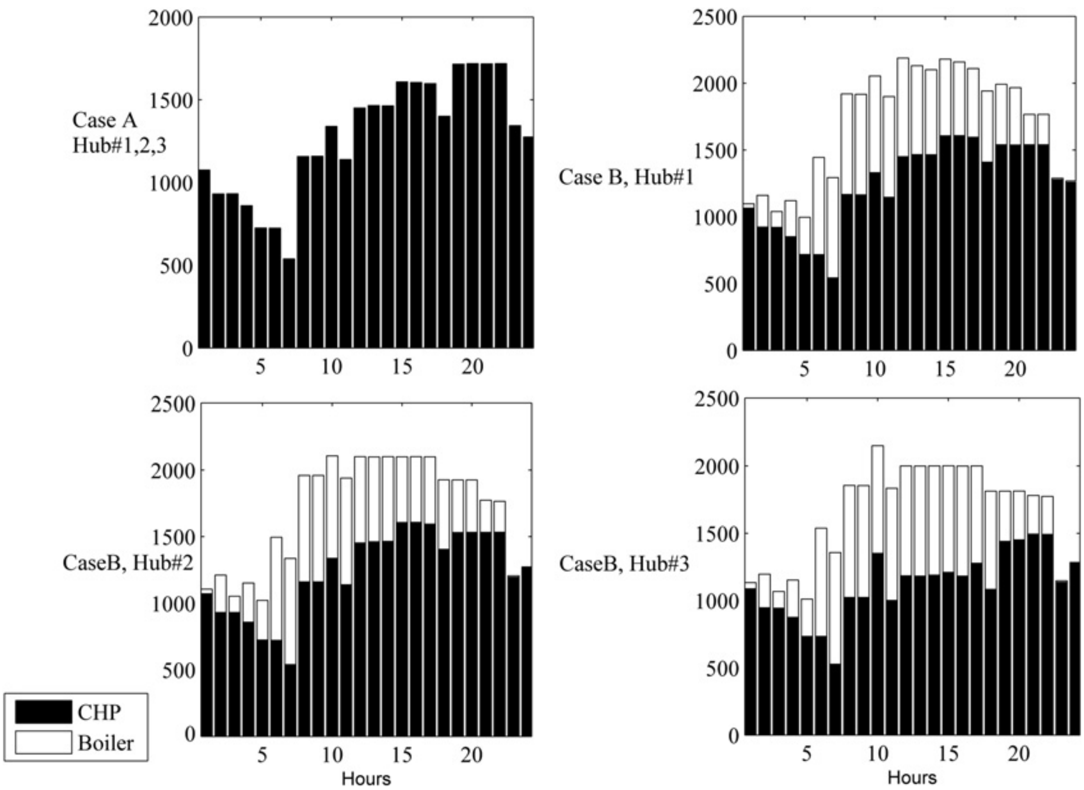

Fig. 9 *Natural gas (kWh) consumption in the CHP and boiler during a typical winter day*

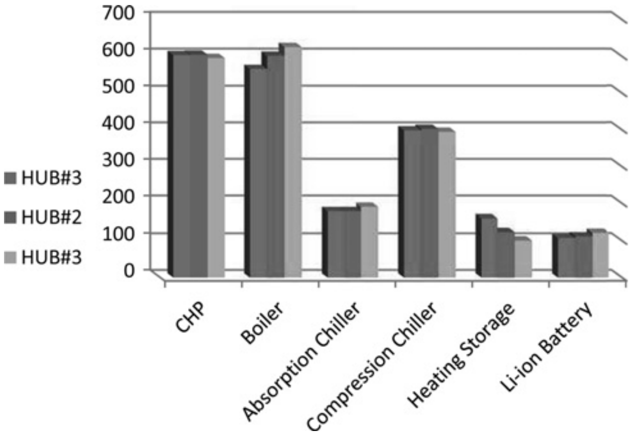

Fig. 10 *Optimal capacity of hub components (kW); Case B*

Network constraints especially for Hub 3 restrain energy exchange with the network. Furthermore, in this case, CHP capacity for each hub is larger compared to Case A and both types of chillers (absorption and compression) are required. Heat storage is required in all the hubs but the corresponding optimum size in each hub is different. Note that during the summer, because less heat is needed, the boiler is used less. In contrast, in winter, because of higher heating load, the boilers are utilised almost all the hours throughout winter days. Fig. 11 shows the dispatch factor for summer and winter indicating that in summer, dispatch factor is almost always equal to one, that is, natural gas is mostly used in CHPs because of lower heating load. On the other hand, dispatch factor is less than one in winter since some of the gas flow drives the boiler to meet higher heating power in winter days.

4.3 Load sensitivity analysis

In this section, the impact of uncertainty in load forecasts on financial analysis results are investigated by using a Monte Carlo approach. The main idea of a stochastic optimisation approach based on Monte Carlo simulation is estimating the expected objective function using a large number of samples [34]. The

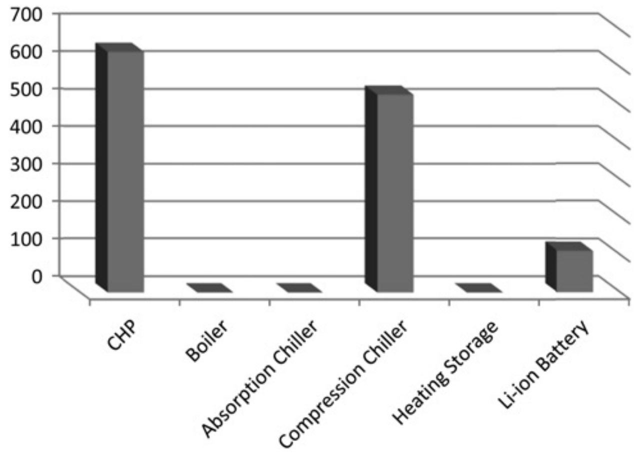

Fig. 12 *Optimal capacity of hub components (kW) considering load uncertainty; Case A*

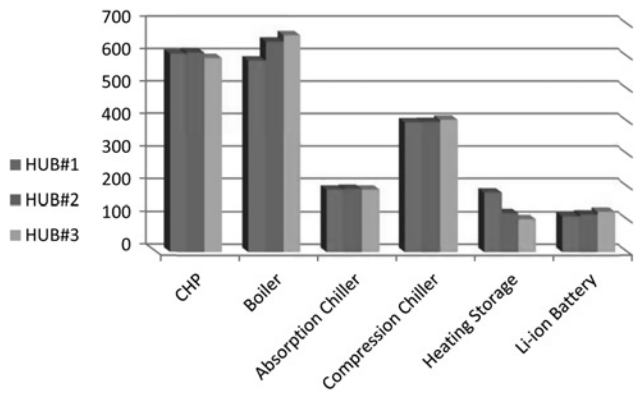

Fig. 13 *Optimal capacity of hub components (kW) considering load uncertainty; Case B*

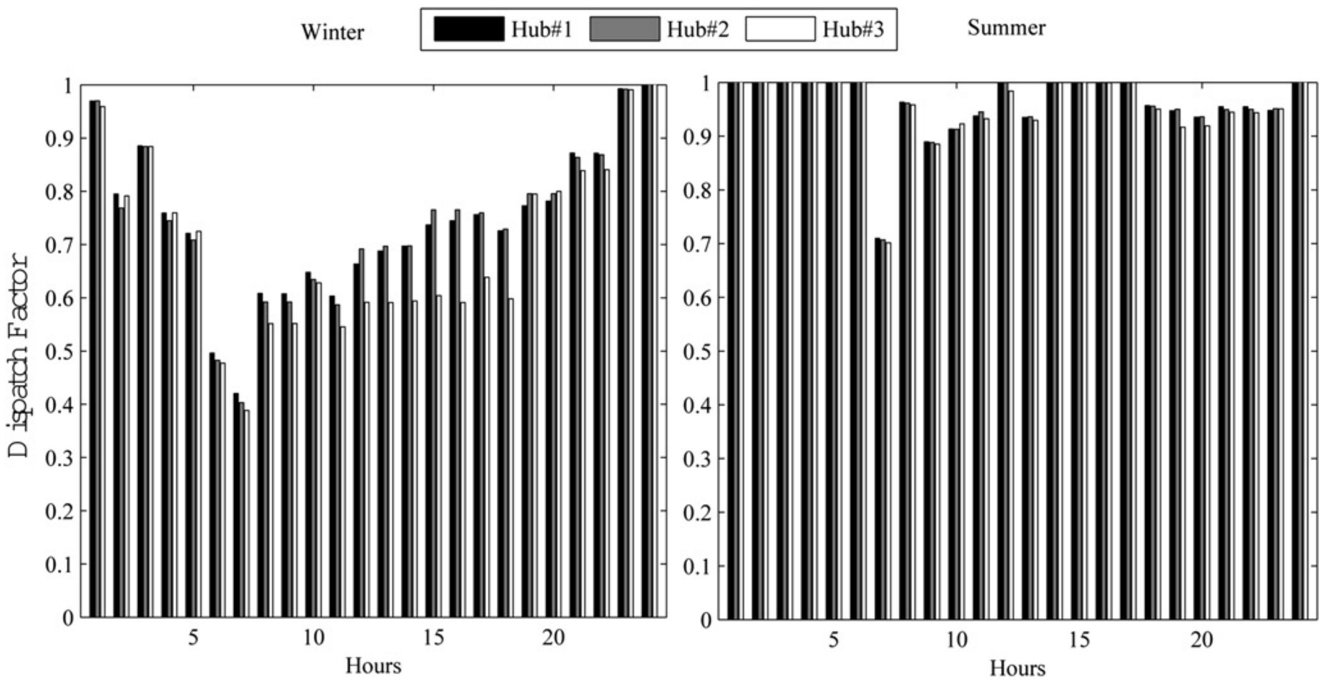

Fig. 11 *Dispatch factor of individual hubs for a typical summer and winter days*

electrical, heating and cooling load estimates are considered as random variables with normal distribution with mean values shown in demand curves previously. Therefore expected net present value is defined as

$$\max\left(\text{ENPV} = \sum_s \text{NPV}(s) \times Pr(s)\right) \quad (41)$$

The computation time required to perform Monte Carlo simulations on a large number of scenarios (10 000 scenarios are used here) is quite high. Therefore, to reduce the computation time, the scenario reduction approach is used; it provides an acceptable approximation of the original system based on a less number of scenarios (20 scenarios are used here) [27, 34]. The load scenarios are generated considering normal distribution with a variance of

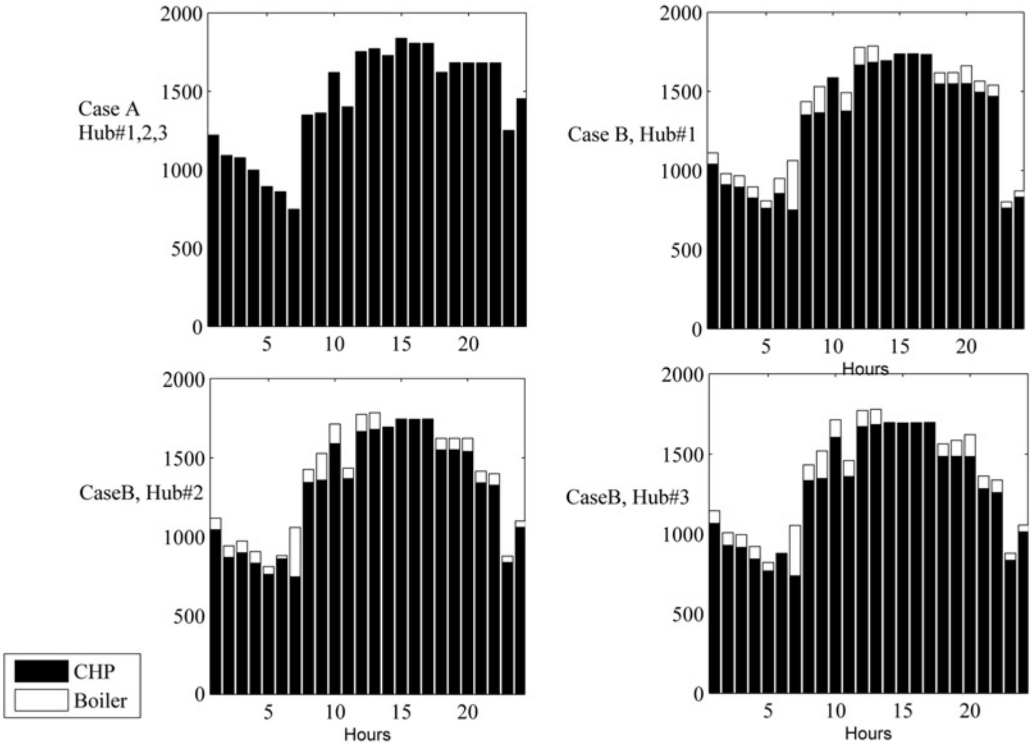

Fig. 14 *Expected amount natural gas consumption in CHP and boiler (kWh) during a typical summer day considering load uncertainty*

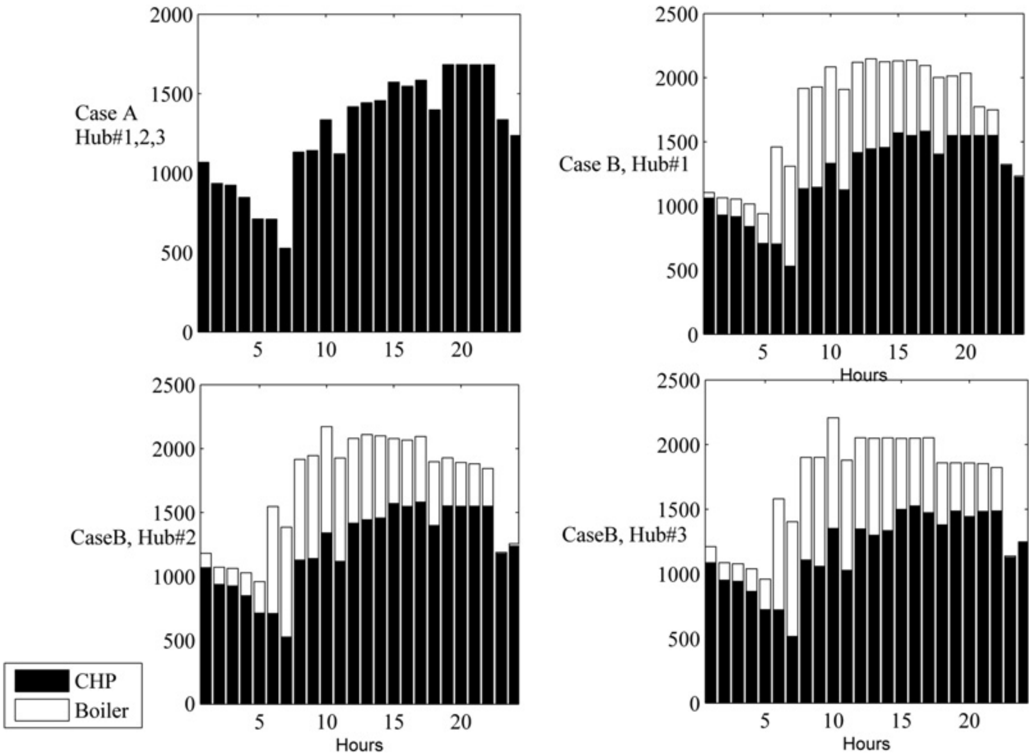

Fig. 15 *Expected amount of natural gas consumption in CHP and boiler (kWh) during a typical winter day considering load uncertainty*

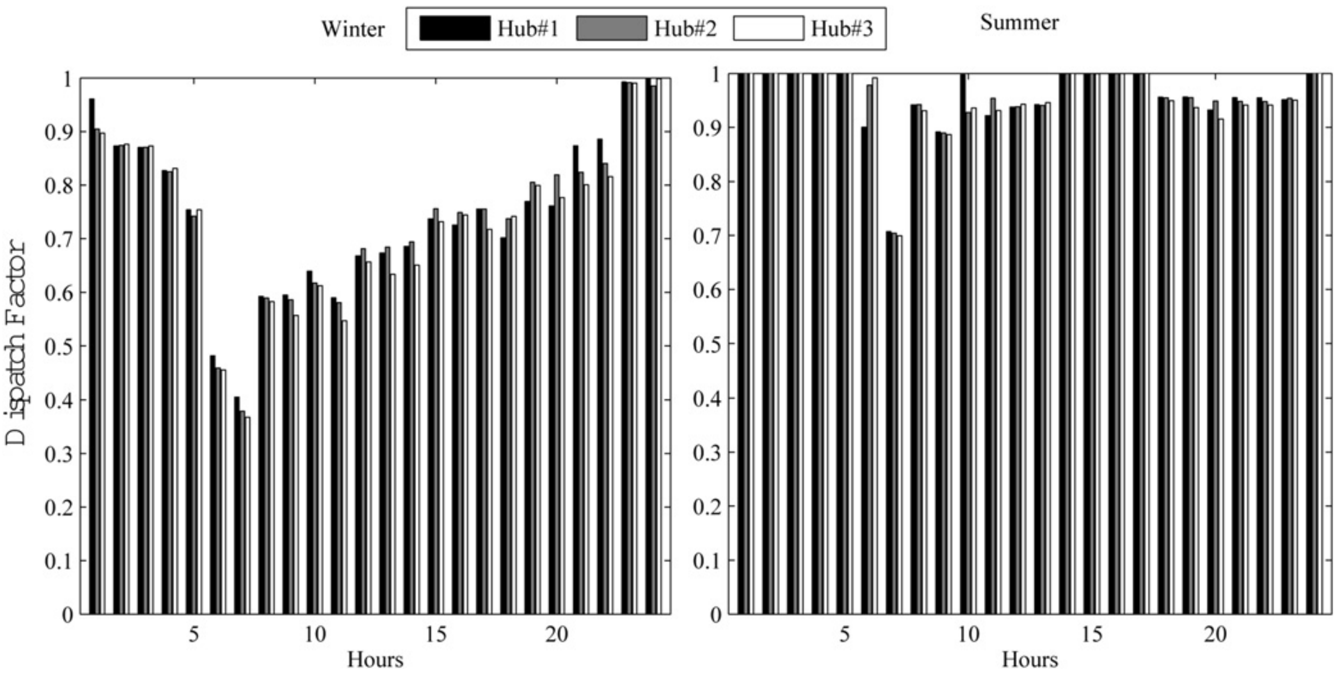

Fig. 16 *Expected dispatch factor considering load uncertainty*

Table 6 Expected economic assessment results considering load uncertainty

Cases	NPV, M$	DPP, years	IRR, %
A	4.95	2	41
B	1.97	5	21

3%. Figs. 12–16 show the results when uncertainties are modelled for each hub. Table 6 shows the economic assessment results of the project considering load uncertainty. In Case A, similar to the case that no uncertainty is modelled, boilers, absorption chillers and heat storages are not required. Also, the optimal size of each component is not significantly different. Minor differences are also observed in terms of project economic assessment. For example, net present value of the project is reduced by 3.64%. Therefore uncertainty has negligible impact in this case. The reason is the

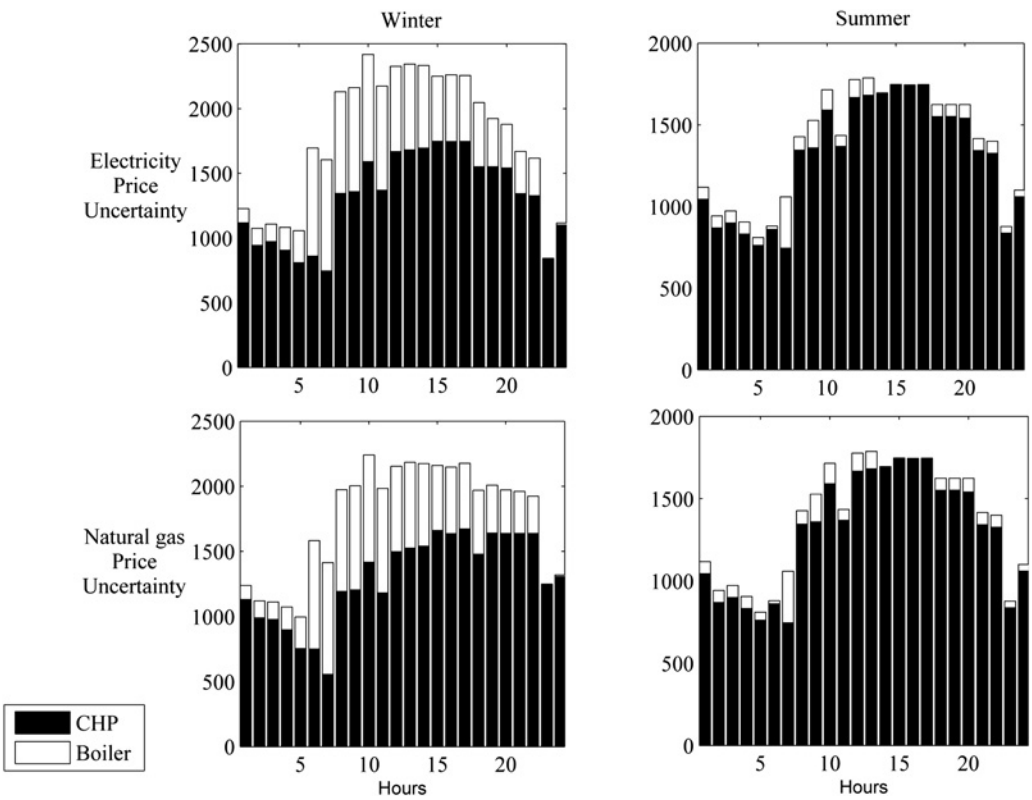

Fig. 17 *Expected amount natural gas consumption in CHP and boiler (kWh) during a typical summer day considering uncertainty in price of energy carriers*

ability of each hub in responding to load variations by utilising interconnected energy networks. In Case B, same as before, it is beneficial to install all the components within each hub; however, higher changes in component capacities in some hubs with respect to the case without uncertainty are observed. For instance, the optimum size of absorption chiller in Hub 1 and Hub 2 would increase by 6.18 and 7.3%, respectively. The size of the boiler in three hubs increases by 3.89, 7.32 and 6.4%, respectively. Utilisation patterns of CHP and boiler and dispatch factors during the day would not change significantly. Project economic evaluation results as can be seen in Table 6 do not show significant changes compared to Table 5. For example, net present value of the project would reduce by 4.57%. These results show that the sensitivity to load changes is low and the designed interconnected energy hubs are able to easily adapt to load changes without causing significant financial loss.

4.4 Price sensitivity analysis

In this section, the impact of uncertainty in electricity price on financial analysis results is examined. Monte Carlo method and scenario reduction approach is used like the analysis of uncertainty in loads. In a real-time pricing environment, market clearing price at a special hour will vary from the predicted price of energy carriers. Thus, the real-time prices of energy carriers can be modelled as a random variable. Previous studies have shown that electricity price can be considered as a random variable with lognormal distribution [35]. In this study, a lognormal distribution has been considered for the price of electricity and natural gas with a variance of 5%. To enable comparison, mean value of the energy carrier prices distribution is the same as what are considered in scenarios of Section 4.2. Also, like Section 4.2, it is assumed that the district heating network is not available. To investigate the effect of uncertainty in the prices of energy carriers, at first 10 000 scenarios of electricity prices and natural gas prices is generated. Then, these scenarios are reduced using the described scenario reduction method.

Fig. 17 shows the expected amount of natural gas consumption in CHP and boiler during the summer and winter days considering uncertainty in price of electricity and natural gas. Fig. 18 depicts the optimal size of hub component taking the uncertainty in the price of electricity into account. As it can be seen, changes in the optimal sizes of components corresponding to Hub 1 are more considerable. For instance, the size of CHP in Hub 1 and Hub 2 has increased by 12.94 and 1.33%, respectively, while the optimal size of CHP in Hub 3 has not changed. As it is expected, uncertainty in the price of electricity effects the optimal size of CHP more than the other components. Because CHP is used to produce electricity within a hub.

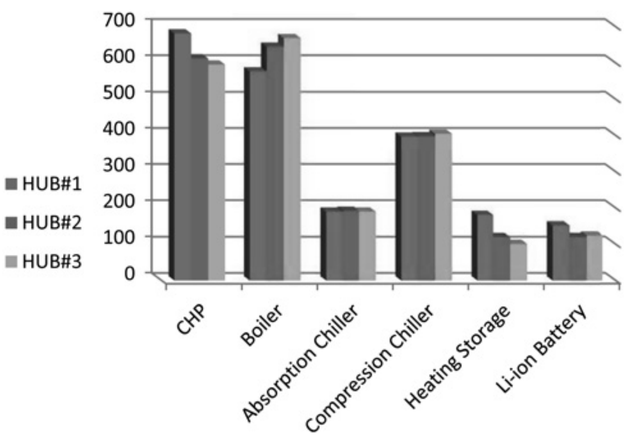

Fig. 18 *Optimal capacity of hub components (kW) considering uncertainty in price of electricity*

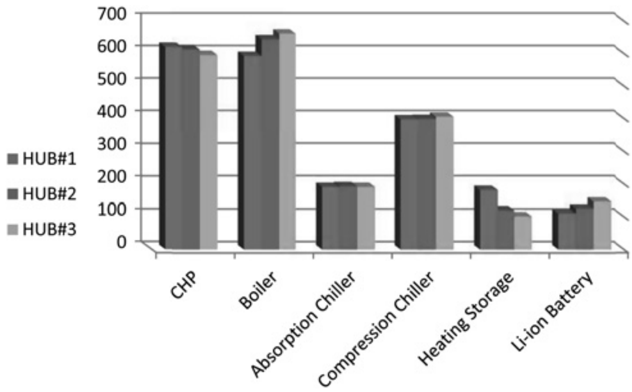

Fig. 19 *Optimal capacity of hub components (kW) considering uncertainty in price of natural gas*

Table 7 Expected economic assessment results considering uncertainty in price of energy carriers

Cases	NPV, M$	DPP, years	IRR, %
electricity price uncertainty	1.86	5	20
natural gas price uncertainly	1.92	5	21

Fig. 19 illustrates the optimal size of hub component in case of uncertainty in price natural gas. In this case, changes in optimal sizes of components are less compared to the uncertainty in the price of the electricity. Moreover, in this case the optimal sizes of boilers show the most changes. The optimal sizes of boilers have increased by 4.78, 6.99 and 5.76%, in Hubs 1, 2 and 3, respectively. Table 7 shows the NPV which will decrease by 10.75 and 7.29% considering uncertainty in the price of electricity and natural gas, respectively.

5 Conclusion

In this paper, a framework to determine the optimal design and size of the hub components in interconnected energy systems has been presented. It includes practical considerations such as maintaining reliability of supplying electricity and heating power, carbon dioxide emissions and physical limitations of electricity and natural gas networks. A three-hub interconnected energy system representing a municipal district/town with two cases (with/without a district heating network) has been examined and the results have been discussed. The study shows that when the district heating system is available, it is beneficial to install CHP and compression chiller and avoid installing heat storage, boiler and absorption chiller. On the other hand, when the district heating system is not available, CHP, heat storage, boiler and absorption chiller should be installed within each hub to meet electricity, heating and cooling power demand. The Monte Carlo method and a scenario reduction technique have been employed to determine the sensitivity of results to uncertainties in heating and electricity demand forecasts as well as uncertainty in prices energy carriers. The model can also help planners study the impact of incentive policies that would encourage hub owners to install CHPs to produce electricity in a decentralised manner.

6 References

1 Swiss Federal Institute of Technology: 'Vision of future energy networks'. Available at: http://www.future-energy.ethz.ch/en/navi-row-1/about-us.html, last accessed January 2013

2 Geidl, M.: 'Integrated modeling and optimization of multi-carrier energy systems'. Ph.D. thesis, Swiss Federal Institute of Technology Zurich, 2007

3 Favre-Perrod, P., Hyde, A., Menke, P.A.: 'Framework for the study of multi-energy networks'. Second Grids Technology Platform General Assembly, 2007
4 Hajimiragha, A., Canizares, C., Fowler, M., Geidl, M., Anderson, G.: 'Optimal energy flow of integrated energy systems with hydrogen economy considerations'. Bulk Power System Dynamics and Control-VII. Revitalizing Operational Reliability, 2007 iREP Symp., 2007, pp. 1–11
5 Hemmes, K., Zachariah-Wolf, J., Geidl, M., Andersson, G.: 'Towards multi-source multi-product energy systems', *Int. J. Hydrog. Energy*, 2007, **32**, pp. 1332–1338
6 Chicco, G., Mancarella, P.: 'Distributed multi-generation: a comprehensive view', *Renew. Sustain. Energy Rev.*, 2009, **13**, pp. 535–551
7 Carradore, L., Turri, R.: 'Modeling and simulation of multi-vector energy systems'. PowerTech, Bucharest, 2009, pp. 1–7
8 Houwing, M., Heijnen, P., Bouwmans, I.: 'Socio-technical complexity in energy infrastructures'. 2006 IEEE Int. Conf. on Systems, Man, and Cybernetics, Taipei, Taiwan, 2006, pp. 906–911
9 Geidl, M., Andersson, G.: 'Optimal power flow of multiple energy carriers', *IEEE Trans. Power Syst.*, 2007, **22**, pp. 145–155
10 Kienzle, F., Ahcin, P., Andersson, G.: 'Valuing investments in multi-energy conversion, storage and demand side management systems under uncertainty', *IEEE Trans. Sustain. Energy*, 2011, **2**, pp. 194–202
11 Schulze, M., Friedrich, L., Gautschi, M.: 'Modeling and optimization of renewables: applying the energy hub approach'. IEEE Int. Conf. on Sustainable Energy Technologies, ICSET, 2008, pp. 83–88
12 Koeppel, G.: 'Reliability considerations of future energy systems: multi-carrier systems and the effect of energy storage'. Ph.D. thesis, Swiss Federal Institute of Technology Zurich, 2007
13 Shahidehpour, M., Fu, Y., Wiedman, T.: 'Impact of natural gas infrastructure on electric power systems', *Proc. IEEE*, 2005, **93**, pp. 1042–1056
14 Morals, M., Lima, J.: 'Natural gas network pricing and its influence on electricity and gas markets'. Power Tech Conf. Proc., Bologna, 2003
15 Marti, B.: 'Emissions of power delivery systems'. Semester thesis, Power Systems and High Voltage Laboratories, ETH Zurich, 2005
16 Serra, L., Lozano, M., Ramos, J., Ensinas, A., Nebra, S.: 'Polygeneration and efficient use of natural resources', *Energy*, 2009, **34**, pp. 575–586
17 Girardin, L., Marechal, F., Matthias, D., Calame-Darbellay, N., Favrat, D.: 'A geographical information based system for the evaluation of integrated energy conversion systems in urban areas', *Energy*, 2010, **35**, pp. 830–840
18 Sun, Z.: 'Experimental investigation of integrated refrigeration system (IRS) with gas engine, compression chiller and absorption chiller', *Energy*, 2008, **33**, pp. 431–436
19 Ren, H., Gao, W., Ruan, Y.: 'Optimal sizing for residential CHP system', *Appl. Thermal Eng.*, 2008, **28**, pp. 514–523
20 Compernolle, T., Witters, N., Van Passel, S., Thewys, T.: 'Analyzing a self-managed CHP system for greenhouse cultivation as a profitable way to reduce CO_2 emissions', *Energy*, 2011, **36**, pp. 1940–1947
21 Sheikhi, A., Mozafari, B., Ranjbar, A.: 'CHP optimized selection methodology for a multi-carrier energy system'. PowerTech, 2011, Trondheim, 2011, pp. 1–7
22 Biezma, M., Cristóbal, J.: 'Investment criteria for the selection of cogeneration plants: a state of the art review', *Appl. Thermal Eng.*, 2006, **26**, pp. 583–588
23 Kalina, J., Skorek, J.: 'Small-scale cogeneration for building applications. Part 2 – optimal sizing of the CHP plant'. Proc. of the Sixth Int. Conf. on Energy for buildings, Wilnius, Lithuania, 2004, pp. 7–8
24 Konstantakos, V., Pilavachi, P., Polyzakis, A., Theofylaktos, C.: 'A decision support model for combined heat and power economic evaluation', *Appl. Thermal Eng.*, 2012, **42**, pp. 129–135
25 Parisio, A., Vecchio, C., Vaccaro, A.: 'A robust optimization approach to energy hub management', *Electric. Power Energy Syst.*, 2012, **42**, pp. 98–104
26 Menon, R., Paolone, M., Marechal, F.: 'Study of optimal design of polygeneration systems in optimal control strategies', *Energy*, 2013, **55**, pp. 134–141
27 Khodaei, A., Shahidehpour, M.: 'Microgrid-based co-optimization of generation and transmission planning in power systems', *IEEE Trans. Power Syst.*, 2013, **28**, pp. 1582–1590
28 Karami, H., Sanjari, M., Hosseinian, S., Gharehpetian, G.: 'An optimal dispatch algorithm for managing residential distributed energy resources', *IEEE Trans. Smart Grid*, 2014, **5**, pp. 2360–2367
29 Bozchalui, M., Hashmi, A., Hassen, H., Cañizares, C., Bhattacharya, K.: 'Optimal operation of residential energy hubs in smart grids', *IEEE Trans. Smart Grid*, 2012, **3**, pp. 1755–1766
30 Fazlollahi, S., Mandel, P., Becker, G., Marechal, F.: 'Methods for multi-objective investment and operating optimization of complex energy systems', *Energy*, 2012, **45**, pp. 12–22
31 Ross, S.: 'Uses, abuses, and alternatives to the net-present-value rule', *Financ. Manag.*, 1995, **24**, pp. 96–102
32 HVAC applications, ASHRAE Handbook, 2013
33 Viswanathan, V., Kintner-Meyer, M., Balducci, P., Jin, C.: 'National assessment of energy storage for grid balancing and arbitrage, volume 2, cost and performance characterization'. Technical report, U.S. Department of Energy, 2013
34 Wu, L., Shahidehpour, M., Li, T.: 'Stochastic security-constrained unit commitment', *IEEE Trans. Power Syst.*, 2007, **22**, pp. 800–811
35 Conejo, A., Nogales, F., Arroyo, J.: 'Price-taker bidding strategy under-price uncertainty', *IEEE Trans. Power Syst.*, 2002, **17**, pp. 1081–1088