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Dynamic Behavior of Multi-Carrier Energy Market in View of Investment Incentives

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Abstract

In this study, a dynamic two-level framework is proposed to model investment incentives in a multi-carrier energy market from strategic company/ point of view. Capacity payment (CP) and firm contract (FC) are assumed as investment incentives to encourage the strategic producer to invest in generation units. In addition, financial incentives to invest in combined heat and power (CHP) include tax rebate and loans. Strategic company’s behaviour is considered as a two-level model so that, in the first level, the objective function is to maximize the profit of strategic producer by participating in an energy hub market. The strategic producer can invest in transmission line, generation units, CHP, and gas furnace. In the second level, the aim is to maximize multi-carrier energy social welfare encompassing heat, gas, and electricity social welfare. In this model, units invested by rival companies are modelled using possible scenarios. Electricity loads in this energy hub system is envisaged to be elastic while heat loads are assumed to be inelastic to the market price. On the other hand, gas loads are indirectly elastic to the price. In addition, in the proposed framework, DC power flow, and an exact gas flow model with

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linearized wye-mouth equation is used. The proposed model is implemented on two case studies including 6-bus system, and an energy hub system encompassing 24-bus IEEE RTS power system and 10-node natural gas system.

Keywords: Energy hubs, CHP, expansion planning, investment incentive, market, multiple energy systems (electricity, natural gas, heat).

1 Nomenclature

Indices

S/S'	index for scenario
y/y'	dynamic stage number (Year)
t	demand block number
$i/q/n$	number of new/existing// generation units for strategic//rival company
c	demand number
m	number of candidate production units for investment
b/b'	power grid Bus
l/l'	Gas network Bus
k	CHP number

Input

TS_{yt}	weighting coefficient of demand block t in year y
SP_s	likelihood of scenario s occurring in year y
BU	SG's investment funds
Y	the cost of annual investment of the generation new unit (€/MW)
$OC_i^{Si}/$	new/existing generation units' operating costs i/q of strategic com-
OC_q^{Sq}	pany i
OC_n^{NS}	Generation units' operating costs of rival company

$\overline{C}_{ytc}$	maximum consumption for demand c in block t and year y (MW)
B_{tc}^d	the proposed price for demand c in block t and year y in scenario S
CU_{yim}	candidate capacity for investment m in the new unit i (MW)
$\overline{P}_q^{Sq} / \overline{P}_n^{NS}$	existing/generation units's capacity q/n of strategic/rival company (MW)
$S_{bb'}$	suseptance of transmission line b-b'. (PU)
$\overline{PF}_{bb'} / \overline{PF}_{bb'}$	capacity of existing/ new transmission line b-b' (MW)
d	annual discount rate
FV/ FP	volume/ price of FC
CP	capacity Payment rate (€/MWh)
$E.O.R^{Si} / E.O.R^{Sq}$	mandatory exit rate of new / available plants
$\overline{P}_k^{C2E}$	Capacity of candidate CHP to be invested (MW)
$\overline{PF}_{bb'}$	Capacity of candidate transmission line to be invested (MW)
P_l^{G2F}	Capacity of candidate gas furnace to be invested (MMBtu)
Y_k^{C2E}	The annual cost resulted from investment of the new CHP (€/MW)
$Y_{bb'}^L$	The annual cost resulted from investment of the new transmission line (€/MW)
Y_l^F	The annual cost resulted from investment of the new gas furnace (€/MW)
$\eta^{C2E} \eta^{C2H}$	Electricity and Heat conversion efficiency Produced by CHP
$\underline{p}_l \ \overline{p}_l$	Minimum and maximum natural gas pressure at each gas bus (PSIG)
$\underline{P}_l^G \ \overline{P}_l^G$	Minimum and maximum natural gas production (MMBtu)
$\overline{F}^G$	Maximum natural gas flowed by pipelines (MMBtu)
K^G	dispatch factor between gas furnace and CHP
η^{pip}	Pipeline constant (MMBtu/PSIG)
L_{ytl}^H	Head demand (MMBtu)
R^T	Tax rebate for investment in CHP
R^L	loan Factor for investment in CHP
$B_{ytl}^H / \overline{B}_{ytl}^G$	The proposed price for buying heat/ gas (€/MMBtu)

Decision variables

$\overline{P}_{yi}^{Si}$	Investment capacity of the new unit i of SG (MW)
$P_{yts}^{Si} / P_{yts}^{Sq} // P_{ytns}^{NS}$	new/ existing// generation unit's i/ q// n production capacity by strategic// rival GENCO in year y in demand block t and scenario s

$\bar{P}_{yy'i}^{S_{iq}} / P_{yy'tis}^{S_{iq}}$	available capacity/ produced power of the new unit i by the strategic company in year y' in years after the construction year y (MW)
$OC_{yi}^{S_{iq}} / B_{yy'tis}^{S_{iq}}$	operating cost/ Proposed price of the new unit i by the strategic company in year y' in years after the construction year y (MW)
CU_{ytim}^b	for the candidate capacity h in investment year y, binary variable equals one, otherwise, it equals zero
$B_{ytis}^{S_i} / B_{ytqs}^{S_q}$	new/existing generation unit's proposed price i/q by strategic company in the block y, demand block t, and scenario s (€/MWh)
B_{ytns}^{NS}	Generation unit's proposed price n by non strategic company in the block y, demand block t, and scenario s (€/MWh)
C_{ytes}	power consumption for demand c in year y, block demand t, and scenario s (MW)
$A_{y t b s}$	the voltage angle of bus b in block demand t, and scenario s
$U_{yk}^C / U_{yy'k}^C$	Binary variable for CHP investment
$U_{ybb'}^L / U_{yy'bb'}^L$	Binary variable for transmission line investment
$U_{yl}^F / U_{yy' l}^F$	Binary variable for gas furnaces investment
$\tilde{P}_{ytk}^{C2E} / \tilde{P}_{yy'tk}^{C2E}$	Electricity produced by New CHP (MW)
$\tilde{P}_{ytk}^{C2H} / \tilde{P}_{yy'tk}^{C2H}$	Heat produced by New CHP (MMBtu)
$\tilde{P}_{ytl}^{G2C} / \tilde{P}_{yy'tl}^{G2C}$	Gas required for supplying CHP (MMBtu)
P_{ytl}^{G2E}	Gas required for supplying thermal generation units (MMBtu)
π_{ytl}	Gas pressure at each gas bus (PSIG)
P_{ytl}^G	Gas produced by utility (MMBtu)
F_{ytl}^G	Natural gas flowed by pipelines (MMBtu)
P_{ytl}^{G2F}	Natural Gas required for supplying existing gas furnace (MMBtu)
$\tilde{P}_{ytl}^{G2F} / \tilde{P}_{yy'tl}^{G2F}$	Gas required for supplying new gas furnace (MMBtu)
$\tilde{B}_{ytk}^{C2H} / \tilde{B}_{yy'tk}^{C2H}$	The proposed price by CHP for selling heat (€/MMBtu)
$\tilde{B}_{ytl}^{F2H} / \tilde{B}_{yy'tl}^{F2H}$	The proposed price by gas furnace for selling heat (€/MMBtu)
B_{ytl}^G	The proposed price by gas gus supplier for selling gas (€/MMBtu)

1. Introduction

When the existing production system in a power system cannot meet the consumer's demand, new production units have to be added [1–3]. Therefore, an investment planing is required such that the energy generation can meet the energy consumption in the long term. In the traditional frameworks, energy infrastructure planning used to be separately done while power resources' expansion planning is entwined with gas and heat resources' planning. This type of planning is influenced by a noticeable growth in use of energy hubs system and distributed energy resources like combined heat and power (CHP)[4]. Consequently, to obtain optimal dispatch of energy in a multi-carrier energy system, technical and economic features of resources expansion planning have changed [5]. Gas-fired power units and distributed energy resources (DERs) like CHP, electrical boiler, electrical heat pump, and gas boiler link power markets to heat, and gas markets. Therefore, electricity market, heat market, and gas market are influenced by each other.

In addition to electricity market, there is a market for natural gas. Natural gas production and combustion are more environment-friendly than coal or oil. In 1978, to increase reliability and economic efficiency of natural gas network, gas regulation is justified by The Federal Energy Regulatory Commission (FERC)[6]. Between 1985 and 2000, a national gas market emerges in the US so that gas suppliers and local distribution companies could contract to sell gas with exchangeable transport rights (ETR). On the other hand, gas consumers can directly participate in the natural gas market like Atlanta gas market. As a result, gas shortage is finished by controlling the price[7, 8].

In addition to electricity and gas markets, heat market include the market for the heat generated by gas furnace, CHP, and other distributed energy resources (DERs). CHP technology is involved in all aforementioned markets. The motivation behind investing in CHP is the fact that this technology can lead to resiliency of energy infrastructure [9, 10]. Some states, encompassing Connecticut and New York, provide loans and grants to motivate individuals and businesses to invest in CHP to increase resiliency and reliability of energy infrastructure. In addition, using

CHP can contribute to energy efficiency, a decrease in pollutants, and an increase in reliability of multi-carrier energy system. There is 70 Gigawatt CHP in US which represents 0.7% of the whole generation capacity[5].

New production units has always been a challenge due to the uncertainties in parameters and input data resulting from the long-term nature of the issue, errors in predictions, and the simultaneous presence of several (often conflicting) goals [11–14]. Some techniques regarding uncertainty and risk assessment can be found in [15–17]. An investor will only invest in production equipment, if he believes it will have acceptable profitability during its life [18, 19].

If properly defined policies are not developed by policymakers and regulators, incentives to invest in the market may reduce [20, 21]. Therefore, investment in such markets requires assurance of return on investment in the long-term [22–24]. This is a challenge to market policy makers because in addition to creating mechanisms to ensure the return on investment for investors, they should also take into account social welfare [25–27]. Nonetheless, it seems unlikely that relying solely on electrical energy market and its price changes will lead to satisfactory results in achieving the production of sufficient electricity capacity. As a result, market regulators use incentives to encourage investment in power generation. The impact of investment incentives to expand production has been studied in various studies including, [28–32]. In [28], mechanisms such as energy only (EO), capacity payment (CP), capacity obligation systems, and capacity subscription are presented and the investment is investigated dynamically. On the other hand, because of aforementioned benefits of CHP, investment incentive including rebates, low-interest loans, grants, and direct income tax deductions have already proposed to motivate individuals and businesses to invest in CHP. Some grants consider payments or rebates according to the investment size of the CHP to be invested(\$/kW)[33, 34]. For example, the Maryland Energy Administration provides funds up to \$500,000 per project to encourage to invest in CHP. Different models have been already proposed to consider investment incentive for energy hub market or only one market.

In [29], a model is presented to determine the effects of forward contracts on expansion of production in an oligopoly market modelled by Cournot model. In

[30], a simple model is presented to study the dynamic impact of investment incentives based on non-collusive Markovian equilibria. They considered each generation company's (GENCO) investment decisions on the basis of its existing capacity. Researchers in [31] dynamically modelled the investment capacity using Markov perfect and open-loop equilibria for hydroelectric and thermal generating plants. The thermal power plants included CP investment incentives. Choosing the right model is very important for planning generation expansion and studying various investment designs in the market. In this study, bi-level model is used for more accuracy. At the first-level, investment decisions are taken into account and optimization problem of market clearing can be solved at the second-level, taking into account investment decisions at the first-level. The bi-level model, as a mathematical optimization problem constrained by another optimization problem, has been applied to various problems related to the electricity market. Examples of bi-level model in the problems related to operation can be seen in [35–37]. Cournot model was used in [38] for market clearing, while [25, 36] used supply function model for this purpose. In [5, 39], energy hub investment models are proposed by considering power grid and natural gas network. Minimizing the cost resulting from investment and operation of multi-carrier energy system is envisaged as an ultimate aim. In [4], resilient operation of energy hub micro-grids is investigated to recognize critical components of the power system by a bi-level model. According to [4], inter-dependency of energy infrastructure can affect resiliency of energy supply.

Fig. 1 shows the framework and ideas used in this article. In Fig. 1, the synergies among different energy infrastructure including electricity, heat, and gas systems are considered. In the proposed model, a dynamic planning includes long term planning and operation planning. In the long term planning, the objective function is to maximize the profit of strategic producer by participating in the energy hub market. The strategic producer can invest in transmission line, generation units, CHP, and gas furnace. In the operation planning, the aim is to maximize the multi-carrier energy social welfare encompassing heat, gas, and electricity social welfare. Heat and electricity demand growth is considered in the dynamic planning. The

Figure 1: The proposed framework

gas load is the amount of fuel that gas-fired power generation consumes to produce electricity. In this study, we investigated CP mechanism via a dynamic approach, which contains both new and existing units while CP is not considered in [12, 25, 40–43]. In addition, the effect of the rate of forced outage for new and existing power plants is investigated. In this study, FC market is presented dynamically and the impacts of firm contract rate are investigated in the energy hub system while FC is not considered in [19, 25, 36, 41, 44, 45]. The simultaneous effect of CP and FC in the dynamic approach is assumed as a SH market. It is assumed in this market that the new units use both FC and CP incentives. In addition, tax rebate and loans are envisaged as investment incentives for CHP.

2. Features related to time in the operation and planning problems

In this study, the first-level is related to planning problem and long-term investment. However, the second level is related to the operation problem and short-term investment. Each of the long-term and short-term dimensions of the problem of investments is explained below.

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112 2.1. *The long-term dimension including the planning problem*

113 The dynamic approach includes multiple stages. Each stage can take one to
114 several years [46, 47]. This article assumes that each step is equal to one year. In
115 the simulation, the results are presented for each year. The dynamic approach in
116 this study consists of 5 stages for the 6 buses system and 10 years for energy hub
117 system so that the rate of annual demand growth is assumed to be 0.1 and the
118 annual interest rate is assumed to be 0.087. Due to the uncertainty in the dynamic
119 approach, non-anticipativity should be addressed in this study.

120 2.1.1. *Non-anticipativity in multistage stochastic programming*

121 Applying non-anticipativity constraints for decision-making variables is impor-
122 tant in all stochastic programming problems, especially multistage (multi-year)
123 ones [48–50]. If the realisations of stochastic processes are identical up to stage
124 n , the values of all decision variables for these scenarios need to be identical up
125 to stage n . However, without the non-anticipativity constraints, values of decision
126 variables for the scenarios may not be identical up to stage n [51].

127 2.1.2. *Investment incentives*

128 Investment incentives include capacity payment, firm contract, and financial in-
129 centives to invest in CHP. First, Market designers in several countries and regions
130 have come to the conclusion that instead of paying a lot of money to generators
131 sporadically for deficiencies created due to price increase, it is more appropriate to
132 pay lower amounts of money to them on a regular basis [41, 43, 52]. These pay-
133 ments will be commensurate with the available productive capacity of each gen-
134 erator. Capacity payments create a flow of income, which is independent of the
135 electrical energy market. These payments must compensate for at least part of the
136 investment costs of new production units and encourage production companies to
137 keep ready units that are rarely called upon for generation. Increasing the total
138 standby capacity, these payments reduce the risk of shortages, but do not elimi-
139 nate it. Second, Firm contracts guarantee the sale of electrical energy produced by
140 the new plant in a fixed price [53]. They eliminate the price risks, over which the

power plant owner has very little control. Therefore, the plant owner should only consider risks associated with the operation of the plant. Operating risks, are risks associated with the failure of the power plant that hinder production of electricity and fulfillment of contractual obligations. FC volume is a percentage of the capacity of the plant envisaged for construction. FC cost is considered as a constant in the proposed model in this study. In this study, FC is only for new units. **Third, because of the aforementioned benefits of CHP, financial incentives including tax rebate and loans are considered to motivate individuals and businesses to invest in CHP.**

2.2. Short-term dimension for the operation problem: market-clearing

Game theory has been used extensively to model spot market. Models suggested in game theory are: Cournot Equilibrium, Bertrand Equilibrium, Stackelberg model, Conjectural Variations, and Supply Function [54]. The decision variable in Bertrand Equilibrium is price. Bertrand Equilibrium is similar to perfect market where the market has at least two actors with unlimited authority. That does not match with the real market. The decision variable in Cournot Equilibrium is of quantity nature. Price forecasting in this model depends heavily on assumptions considered and are not reliable. In Stackelberg model, first, a decision is made on the quantities by the leader and other decisions are dependent on this first decision. Conjectural Variations model is based on conjecture variables, which in fact include the impacts of power plants on the price of electricity. In the supply function, decision variables are both of quantity and price nature. Using supply function model in England and Wales' electricity market showed that the model could very well be used to predict price [35]. In [55], the supply function model is used to investigate the impact of the demand bids in ERCOT market. In these studies, input and output features of existing and new power plants (investment choices) are modelled using piecewise linear model in the form of blocks including 2 offers or bids.

3. The proposed algorithm for solving investment problem in different markets

The algorithm needed for studying the impact of energy hub investment incentives is provided in Figure 2. Available natural gas supplier, pipeline configuration, existing and candidate gas Furnace, CHP, power generation, and transmission lines, inelastic heat and gas demand, elastic electricity demand and power grid are inputs to the the proposed algorithm. Multi-carrier energy planning is considered as a bi-level problem. First, the strategic investor decides where and when to invest in transmission line, generation units, CHP, and gas furnace. Then the impact of energy hub investments on the market-clearing optimization problem is investigated. It should be noted that EO represents energy only markets, CP represents capacity payment markets, FC represents the firm contract markets and SH represents smart hybrid markets.

The type of market is specified at the beginning of the flowchart. Payments for preparedness capacity include both the existing and new units, while FC investment incentives in FC and SH markets only include new units. The investment problem in the first-level will maximize the net return on investment in the total planning time for each market. Each new unit will be considered as an existing plant in the years after its establishment. Non-strategic company's investment decisions are considered as uncertainties and modelled using a set of scenarios.

At the second level, social welfare is maximized for each year, each scenario, and each time block. Social welfare in the second level includes electricity, heat and gas social welfare. Firm contract investment incentives in FC and SH markets affect the generation and consumption equilibria and the related constraints. Part of the electricity consumers' demands in market clearing is provided in proportion to the firm contract volume. The new plant established using firm contract must meet consumer demand in proportion to the firm contract volume in the years after its establishment. DC power flow and an exact gas flow model with linearized wye-mouth equation is used at the second level. The operation problem at the second-level is considered as a constraint for the problem at the first-level for each scenario

Figure 2: The proposed energy hub algorithm for solving the problem of the impact of investment incentives for power plants and CHP

and each demand block in various years. For simplicity, time blocks are not shown in the flowchart.

4. Problem formulation

The mathematical model of the proposed framework is described in the following sections.

A. The first-level of EO, CP, FC, and SH markets

The first-level includes the objective function (Eqs. 1-5), overall constraints (Eqs. 10-15), dynamic dependency constraints (Eqs. 16-18), and constraints relating to non-anticipativity (Eqs. 21-23).

206 4.1. Objective function of the first-level
207

$$\max \text{Profit}^{\text{EO}} + \text{Profit}^{\text{SH}} + \text{Profit}^{\text{EH}} \quad (1)$$

208 The objective function of (Eq. 1) is maximization of the SG/s net benefit in the
209 planning period. As can be seen, the net profit is composed of two statements, i.e.
210 SG/s benefit in the EO market and its benefit resulting from investment incentives.

$$\begin{aligned} \text{Profit}^{\text{EO}} = & \sum_y \left(\frac{1}{1+d} \right)^y \sum_i B_i^d \bar{P}_{yi}^{\text{Si}} \\ & - \sum_s \text{SP}_s \sum_y \left(\frac{1}{1+d} \right)^y \sum_t \text{TS}_{yt} \\ & \left(\sum_{i|i \in b} P_{ytiw}^{\text{Si}} \text{MCP}_{ytbs} - \sum_i P_{yits}^S \text{OC}_i^{\text{Si}} \right) \\ & + \left(\sum_{q|q \in b} P_{ytqs}^{\text{Sq}} \text{MCP}_{ytbs} - \sum_q P_{ytqs}^{\text{ES}} \text{OC}_q^{\text{Sq}} \right) \end{aligned} \quad (2)$$

212 Eq. 2 shows the SG's net profit in the EO market and is composed of two state-
213 ments. The first statement represents the net profit achieved in the spot market
214 (operation), while the second is related to the SG's cost of investment. The state-
215 ment means that the new unit number i has been built in the bus b .

$$\text{Profit}^{\text{SH}} = \text{Profit}^{\text{CP}} + \text{Profit}^{\text{FC}} \quad (3)$$

217 Eq. 3 shows the profit resulting from investment incentives including investment
218 incentives of CP and FC. The total net profit of SG in the CP and FC markets is equal
219 to its net profit in the SH market.

$$\begin{aligned} \text{Profit}^{\text{CP}} = & \sum_s \text{SP}_s \left(\text{CP}_t \sum_i \bar{P}_{yi}^{\text{Si}} (1 - \text{FV})(1 - \text{F.O.R}^{\text{Si}}) \right. \\ & \left. + \text{CP}_t \sum_q \bar{P}_q^{\text{Sq}} (1 - \text{F.O.R}^{\text{Sq}}) \right) \end{aligned} \quad (4)$$

221 Eq 4 represents the profits coming from investment in power plants using CP
222 investment incentives.

$$\text{Profit}^{\text{FC}} = \sum_s \text{SP}_s \sum_y \left(\frac{1}{1+d} \right)^y \sum_t \text{TS}_{yt} \text{FC}_t \left(\text{FV} \sum_i \bar{P}_{yi}^{\text{Si}} + \text{FV} \sum_i \sum_{y'} \bar{P}_{yy'i}^{\text{Siq}} \right) \quad (5)$$

224 Eq. 5 shows SG's profits coming from the sale of electricity by firm contracts.

$$\text{Profit}^{\text{EH}} = \text{Profit}^{\text{CHP}} + \text{Profit}^{\text{Furnace}} - \text{Cost}^{\text{Line}} \quad (6)$$

$$\begin{aligned} \text{Profit}^{\text{CHP}} = & \sum_y \left(\frac{1}{1+d} \right)^y ((1 - R^T) \sum (u_{yk}^C + u_{yy'k}^{C'}) \bar{P}_k^{\text{C2E}} Y_k^{\text{C2E}}) \\ & - \sum_s \text{SP}_s \sum_y \left(\frac{1}{1+d} \right)^y \sum_t \text{TS}_{yt} (+ \sum \tilde{P}_{ytk}^{\text{C2H}} B_{ytl}^{\text{H}} + \sum \tilde{P}_{yy'tk}^{\text{C2H}} B_{ytl}^{\text{H}} \\ & + \sum \tilde{P}_{ytk}^{\text{C2E}} \text{MCP}_{ytbs} + \sum \tilde{P}_{yy'tk}^{\text{C2E}} \text{MCP}_{ytbs} - \sum \tilde{P}_{ytl}^{\text{G2C}} B_{ytl}^{\text{G}} - \sum \tilde{P}_{yy'tl}^{\text{G2C}} B_{ytl}^{\text{G}}) \end{aligned} \quad (7)$$

$$\begin{aligned} \text{Profit}^{\text{Furnace}} = & \sum_y \left(\frac{1}{1+d}\right)^y (\sum_l (U_{yl}^F + U_{yy'l}^F) P_l'^{G2F} Y_l^F) \\ & - \sum_s SP_s \sum_y \left(\frac{1}{1+d}\right)^y \sum_t TS_{yt} (\sum_{ytl} \tilde{P}_{ytl}^{F2H} B_{ytl}^H + \sum_{yy'tl} \tilde{P}_{yy'tl}^{F2H} B_{ytl}^H) \\ & - \tilde{P}_{ytl}^{G2F} B_{ytl}^G - \tilde{P}_{ytl}'^{G2F} B_{ytl}^G - \sum_{i \in l} \sum_{k \in l} P_{ytl}^{G2E} B_{ytl}^G \end{aligned} \quad (8)$$

$$\text{Cost}^{\text{Line}} = \sum_y \left(\frac{1}{1+d}\right)^y \sum (U_{ybb'}^L + U_{yy'bb'}^L) \bar{P}_{bb'} Y_{bb'}^L \quad (9)$$

Eq. 6 involves profit related to investment in gas furnace, CHP and transmission lines and their operation. Eq. 7 and Eq. 8 are related to the profit resulting from investments in CHP and gas furnace, respectively. Tax rebate is considered as investment incentive for CHP. Eq. 9 presents the cost of new transmission line.

4.2. General constraints of the first-level

$$\bar{P}_{yi}^{Si} = \sum_m CU_{yim}^b CU_{yim}, \sum_m CU_{yim}^b = 1, CU_{yim}^b \in \{0, 1\} \quad \forall i, \forall y \quad (10)$$

$$\sum_y U_{yk}^C \leq 1; \forall k \quad (11)$$

$$\sum_y U_{yl}^F \leq 1; \forall l \quad (12)$$

$$\begin{aligned} & \sum_y \left(\frac{1}{1+d}\right)^y [\sum_i Y_i (\bar{P}_{yi}^{Si} + \sum_{y'y} \bar{P}_{yy'i}^{Siq}) + R^L (\sum_k (U_{yk}^C + \sum_{yy'} U_{yy'k}^C) \bar{P}_k^{C2E} Y_k^{C2E}) \\ & + \sum_b \sum_{b'} (U_{ybb'}^L + \sum_{yy'} U_{yy'bb'}^L) \bar{P}_{bb'} Y_{bb'}^L \\ & + \sum_l (U_{yl}^F + \sum_{yy'} U_{yy'l}^F) P_l'^{G2F} Y_l^F] \leq BU \end{aligned} \quad (13)$$

$$B_{yitis}^{Si} \geq 0 \quad \forall y, \forall t, \forall i, \forall s \quad (14)$$

$$B_{yitqs}^{Sq} \geq 0 \quad \forall y, \forall t, \forall q, \forall s \quad (15)$$

The reason for Eq. 10 is that among the various investment options, only one is chosen for generation investment. In addition, both of available technologies (base and peak) can be established in each bus. Eqs. 11 and 12 are associated with investments in CHP and gas furnace, respectively. Due to financial limitations of companies and obstacles against the exercise of market power in the long term, the companies' investment is limited as shown in Eq. 13. The positive offers of SG for new and existing units are shown in Eqs. 14 and 15 respectively.

4.2.1. Dynamic dependency constraints on the first-level

$$\bar{P}_{yy'i}^{Siq} = \bar{P}_{yi}^{Si} \quad \forall y, y' \in \{\bar{P}_{yi}^{Si} > 0, y > y'\}, \forall i \quad (16)$$

$$OC_{yi}^{Siq} = OC_i^{Si} \quad \forall y, y' \in \{\bar{P}_{yi}^{Si} > 0, y > y'\}, \forall i \quad (17)$$

$$B_{yy'tis}^{Siq} \geq 0 \quad \forall y, y' \in \{\bar{P}_{yi}^{Si} > 0, y > y'\}, \forall t, i, s \quad (18)$$

$$U_{yy'k}^{'C} = U_{yk}^C; \forall y, y' \in \{U_{yk}^C > 0, y > y'\}, \forall k \quad (19)$$

$$U_{yy'l}^{'F} = U_{yl}^F; \forall y, y' \in \{U_{yl}^F > 0, y > y'\}, \forall l \quad (20)$$

Eqs. 16 to 20 show the high-level dynamic dependency constraints. Eq. 16 shows that the newly installed units will be considered available units in the network in the coming years. Eq. 17 is for operating costs of these units in the coming years. Eq. 18 shows that SG's offers for new units in the years after construction is positive. Eqs. 19 and 20 present the dynamic dependency constraints related to investments in CHP and gas furnace.

4.2.2. Constraints relating to non-anticipativity of the first-level

$$B_{ytis}^{Si} = B_{ytis'}^{Si} \quad \forall y, s, s' \in S^{NAP}, \forall t, i \quad (21)$$

$$B_{ytqs}^{Sq} = B_{ytqs}^{Sq} \quad \forall y, s, s' \in S^{NAP}, \forall t, q \quad (22)$$

$$B_{yy'tis}^{Siq} = B_{yy'tis'}^{Siq} \quad \forall y, s, s' \in S^{NAP}, \forall y', t, i \quad (23)$$

Eqs. 21 to 23 are related to non-anticipativity constraints of the first-level variables for the target scenarios. They are for bids of new units in the construction year, existing units, and new units in the years following the construction year, respectively.

B. The second-level of EO, CB, FC and SH markets

The second-level problem as the market-clearing problem is defined using the Eqs. 24 to 65. The second-level includes the objective function (Eq. 10), general constraints (Eqs. 28 to 36), dynamics dependency constraint (Eq. 52) and constraints relating to non-anticipativity (Eqs. 60 to 65).

4.2.3. Objective function of the second-level

$$\min -SW = -SW^E - SW^H - \quad (24)$$

$$\begin{aligned} -SW^E = & \sum B_{ytis}^{Si} P_{ytis}^{Si} + \sum B_{ytqs}^{Sq} P_{ytqs}^{Sq} + \sum B_{ytns}^{NS} P_{ytns}^{NS} \sum \tilde{P}_{ytk}^{C2E} \tilde{B}_{ytk}^{C2E} \\ & + \sum \tilde{P}_{yy'tk}^{C2E} \tilde{B}_{yy'tk}^{C2E} - \sum B_{tcs}^d C_{ytcs} \end{aligned} \quad (25)$$

$$\begin{aligned} -SW^H = & \sum \tilde{P}_{ytk}^{C2H} \tilde{B}_{ytk}^{C2H} + \sum \tilde{P}_{yy'tk}^{C2H} \tilde{B}_{yy'tk}^{C2H} + \sum P_{ytl}^{F2H} B_{ytl}^{F2H} + \sum \tilde{P}_{ytl}^{F2H} \tilde{B}_{ytl}^{F2H} \\ & + \sum \tilde{P}_{yy'tl}^{F2H} \tilde{B}_{yy'tl}^{F2H} - \sum L_{ytl}^H B_{ytl}^H \end{aligned} \quad (26)$$

$$\begin{aligned} -SW^G = & \sum P_{ytl}^G B_{ytl}^G - \sum P_{ytl}^{G2E} \bar{B}_{ytl}^G - \sum P_{ytl}^{G2F} \bar{B}_{ytl}^G \\ & - \sum \tilde{P}_{ytl}^{G2F} \bar{B}_{ytl}^G - \sum \sum_{y'} \tilde{P}_{yy'tl}^{G2F} \bar{B}_{yy'tl}^G - \sum \tilde{P}_{ytl}^{G2C} B_{ytl}^G - \sum \sum_{y'} \tilde{P}_{yy'tl}^{G2C} \bar{B}_{yy'tl}^G \end{aligned} \quad (27)$$

The objective function of the lower level is the minimization of the minus social welfare including electrical social welfare (SW^E), heat social welfare (SW^H), and gas social welfare (SW^G). In other words, social welfare is maximized as shown in Eq. 24- 27. Eq. 25 presents minus electrical social welfare while Eq. 26 and Eq. 27 are associated with the heat social welfare, and gas social welfare, respectively.

4.2.4. General constraints of the second-level

Power system constraints:

$$\begin{aligned} & \sum_{c|c \in b} C_{ytcs} + \sum_b S_{bb'} S_B (A_{ytbs} - A_{ytb's}) + \sum_b S_{bb'} S_B U_{ybb'}^L (A_{ytb} - A_{ytb'}) \\ & + \sum_b \sum_{y'} S_{bb'} S_B U_{yy'b'}^L (A_{y'tb} - A_{y'tb'}) \\ & + \sum_{y'} \sum_b S_{bb'} S_B * U_{yy'b'}^L (A_{ytb} - A_{ytb'}) - \tilde{P}_{yt(k \in n)}^{C2H} - \sum_{y'} \tilde{P}_{yy't(k \in n)}^{C2H} \\ & - \sum_{i|i \in b} P_{ytis}^{Si} - FV \sum_{i|i \in b} \bar{P}_{yi}^{Si} - \sum_{i|i \in b} P_{yy'tis}^{Si} - FV \sum_{i|i \in b} \bar{P}_{yy'i}^{Si} \\ & - \sum_{q|q \in b} P_{ytqs}^{Sq} - \sum_{n|n \in b} P_{ytns}^{NS} - FV \sum_{n|n \in b, n: new} \bar{P}_{ns}^{NS} = 0 : \\ & MCP_{ytbs} \quad \forall y, \forall t, \forall b, \forall S \end{aligned} \quad (28)$$

$$0 \leq P_{ytis}^{Si} \leq (\bar{P}_{yi}^{Si} - P_{yti}^{SFC}) \quad \forall i, \forall t, \forall y, \forall S \quad (29)$$

$$0 \leq P_{ytqs}^{Sq} \leq \bar{P}_q^{Sq} \quad \forall q, \forall t, \forall y, \forall S \quad (30)$$

$$0 \leq P_{ytns}^{NS} \leq (\bar{P}_n^{NS} - P_{ytj}^{OFC}) \quad \forall n, \forall t, \forall y, \forall S \quad (31)$$

$$0 \leq C_{ytcs} \leq \bar{C}_{ytc} \quad \forall c, \forall t, \forall y, \forall S \quad (32)$$

$$-\overline{PF}_{bb'} \leq S_{bb'} S_B (A_{ytbs} - A_{ytb's}) \leq \overline{PF}_{bb'} \quad \forall b, \forall b', \forall t, \forall y, \forall S \quad (33)$$

$$-\overline{PF}_{bb'} U_{ybb'}^L \leq S_{bb'} S_B (A_{ytbs} - A_{ytb's}) \leq \overline{PF}_{bb'} U_{ybb'}^L \quad \forall b, \forall b', \forall t, \forall y, \forall S \quad (34)$$

$$-\pi \leq A_{ytbs} \leq \pi \quad \forall b, \forall t, \forall y, \forall S \quad (35)$$

$$A_{yt(b=1)s} = 0 \quad \forall t, \forall y, \forall S \quad (36)$$

Eq. 28 is for production and consumption equilibria at each bus. Locational marginal prices (LMPS) are dual variables of constraints related to the balance of power called MCP. It is noteworthy that $n|_{n \in b, n: new}$ means that unit number n is in bus b and is considered as part of NSG's investment units according to the scenarios considered. Eqs. 29-31 are respectively related to constraints of generation capacity of SG's new plants in the construction year, and existing plants, and non-strategic producers' plants. Eq. 32 is related to load elasticity. Eq. 33- 34 are associated with restrictions on power passing through existing and new transmission lines, respectively. Eq. 35 is related to limitation of voltage angle of buses is in DC load flow. S_B represents the power base. Eq. 36 is for slack bus voltage angle.

CHP constraints:

$$\tilde{P}_{ytk}^{C2E} = K^G \eta^{C2E} \tilde{P}_{yt(l \in k)}^{G2C}; \forall y, t, k \quad (37)$$

$$\tilde{P}_{ytk}^{C2H} = K^G \eta^{C2H} \tilde{P}_{yt(l \in k)}^{G2C}; \forall y, t, k \quad (38)$$

$$\tilde{P}_{ytk}^{C2E} \leq \overline{P}_k^{C2E} U_{yk}^C; \forall y, t, k \quad (39)$$

$$\tilde{P}_{ytk}^{C2H} \leq \overline{P}_k^{C2H} U_{yk}^C; \forall y, t, k \quad (40)$$

Eqs. 37- 40 are constraints associated with the operation of CPH in the spot market. The electricity and heat produced by CHP are influenced by a gas dispatch factor between CHP and gas furnace. Eqs. 37- 38 are related to the production of electricity and heat by new CHP. Eqs. 39- 40 present the technical constraints of new CHP.

Gas network constraints:

$$\begin{aligned} P_{ytl}^{G2E} = & \eta^1 + \eta^2 (\sum_{i|l \in b} P_{ytl}^{Si} + FV \sum_{i|l \in b} \overline{P}_{y(i \in l)}^{Si} + \sum_{i|l \in b} P_{yy't(i \in l)}^{Siq} \\ & + FV \sum_{i|l \in b} \overline{P}_{yy'(i \in l)}^{Siq} + \sum_{q|q \in b} P_{ytl(q \in l)}^{Sq} + \sum_{n|n \in b} P_{ytl(n \in l)}^{NS} \\ & + FV \sum_{n|n \in b, n: new} \overline{P}_{(n \in l)s}^{NS} = 0) : \forall y, t, l \end{aligned} \quad (41)$$

$$\underline{\pi}_l \leq \pi_{ytl} \leq \bar{\pi}_l; \forall y, t, l \quad (42)$$

$$\underline{p}_l^G \leq p_{ytl}^G \leq \bar{p}_l^G; \forall y, t, l \quad (43)$$

$$-\bar{F}^G \leq F_{ytl}^G \leq \bar{F}^G; \forall y, t, l, l' \forall q \quad (44)$$

$$F_{ytl}^G = \eta^{pip} \sqrt{|\pi_{l'}^2 - \pi_l^2|}; \forall y, t, l, l' \quad (45)$$

$$p_{ytl}^G = p_{ytl}^{G2E} + \sum_{l'} F_{ytl}^G + p_{ytl}^{G2F} + \tilde{p}_{ytl}^{G2F} + \sum_{y'} \tilde{p}_{yy'tl}^{G2F} + \tilde{p}_{ytl}^{G2C} + \sum_{y'} \tilde{p}_{yy'tl}^{G2C} \forall y, t, l \quad (46)$$

Eq. 41 is the amount of gas needed for supplying thermal generation units. Eqs. 42-44 present gas network limitations related to natural gas pressure, gas supplier's generation, and gas pipeline flow, respectively. In Eq. 47, Wye-mouth equation is presented. Natural gas balance is implemented to the model by using Eq. 46. ChP and gas furnace are assumed to be gas consumers.

Gas furnace constraints

$$p_{ytl}^{F2H} = (1 - K^G) \eta^{F2H} p_{ytl}^{G2F}; \forall y, t, l \quad (47)$$

$$p_{ytl}^{F2H} \leq \bar{p}_l^{G2F}; \forall y, t, l \quad (48)$$

$$\tilde{p}_{ytl}^{F2H} = (1 - K^G) \eta^{F2H} \tilde{p}_{ytl}^{G2F}; \forall y, t, l \quad (49)$$

$$\tilde{p}_{ytl}^{F2H} \leq \bar{p}_l^{G2F} u_{yl}^F; \forall y, t, l \quad (50)$$

Eqs. 47- 50 are constraints associated with operation of gas furnace in the spot market. The heat produced by gas furnace is influenced by the gas dispatch factor between CHP and gas furnace. Eqs. 47- 49 are related to production of heat by exiting and new gas furnace, respectively. Eqs. 48- 50 present the technical constraints of exiting and new gas furnace.

heat balance:

$$L_{ytl}^H = \tilde{p}_{yt(k \in l)}^{C2H} + \sum_{y'} \tilde{p}_{yy't(k \in l)}^{C2H} + p_{ytl}^{F2H} + \tilde{p}_{ytl}^{F2H} + \sum_{y'} \tilde{p}_{yy'tl}^{F2H}; \forall y, t, l \quad (51)$$

Eq. 51 show heat balance constraint for proposed model.

4.2.5. Dynamic dependency constraints on the second-level

$$0 \leq P_{yy'tis}^{Siq} \leq \bar{P}_{yy'i}^{Siq} \quad \forall y, \forall y' \in \{\bar{P}_{y'i}^{Si} > 0, y > y'\}, \forall t, \forall i, \forall S \quad (52)$$

$$-\bar{P}_{bb'} U_{yy'b b'}^L \leq S_{bb'} S_B (A_{ytbs} - A_{ytb's}) \leq \bar{P}_{bb'} U_{yy'b b'}^L \quad \forall b, \forall b', \forall t, \forall y, \forall y' \quad (53)$$

$$\tilde{P}_{yy'tk}^{C2E} = K^G \eta^{C2E} \tilde{P}_{yy't(l \in k)}^{G2C}; \forall y, y', t, k \quad (54)$$

$$\tilde{P}_{yy'tk}^{C2H} = K^G \eta^{C2H} \tilde{P}_{yy't(l \in k)}^{G2C}; \forall y, t, k \quad (55)$$

$$\tilde{P}_{yy'tk}^{C2E} \leq \bar{P}_k^{C2E} U_{yy',k}^C; \forall y, y', t, k \quad (56)$$

$$\tilde{P}_{yy'tk}^{C2H} \leq \bar{P}_k^{C2H} U_{yy',k}^C; \forall y, y', t, k \quad (57)$$

$$\tilde{P}_{ytl}^{F2H} = (1 - K^G) \eta^{F2H} \tilde{P}_{ytl}^{G2F}; \forall y, t, l \quad (58)$$

$$\tilde{P}_{ytl'l'}^{F2H} \leq \bar{P}_l^{G2F} U_{ytl'l'}^F; \forall y, t, l, l' \quad (59)$$

Eq. 52- 53 as the dynamic dependency constraints on the second-level, shows constraints related to production, and transmission line investment in the years after the establishment of new generation units. Eqs. 54- 57 are dependency constraint of new CHP while Eqs. 58- 59 are dependency constrain of new gas furnace.

4.2.6. Non-anticipativity constraints on the second-level

$$P_{ytis}^{Si} = P_{ytis'}^{Si} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall q \quad (60)$$

$$P_{ytqs}^{Sq} = P_{ytqs'}^{Sq} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall q \quad (61)$$

$$P_{ytns}^{NS} = P_{ytns'}^{NS} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall n \quad (62)$$

$$P_{yy'tis}^{Siq} = P_{yy'tis'}^{Siq} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall i \quad (63)$$

$$C_{ytcs} = C_{ytcs'} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall c \quad (64)$$

$$A_{ytbs} = A_{ytbs'} \quad \forall y, \forall s, \forall S' \in S^{NAP}, \quad \forall t, \forall b \quad (65)$$

Eqs. 60 to 65 are non-anticipativity constraints for all second-level variables for the scenarios considered. They are respectively for production variables of new strategic units in the construction year, production of existing strategic units, production of non-strategic units, production of strategic units in the years after the construction year, demand, and the voltage angle of buses.

4.3. Linearization

There are some nonlinear terms and equations in the proposed energy hub planning. The nonlinear equations include Wye-mouth equation and a nonlinear term related to new transmission line.

linearization of Wye-mouth equation:

$$F_{ytl}^G + M^G \leq \frac{\eta^{pip}(\hat{\pi}_l \pi_{ytl} - \hat{\pi}_l \pi_{ytl})}{\sqrt{|\hat{\pi}_l^2 - \hat{\pi}_l^2|}} \leq F_{ytl}^G + M^G; \forall y, t, l, l' \quad (66)$$

In Eq. 66, Wye-mouth equation is linearized by using Taylor series. It is worth to mention that the pressure difference between two sides of each pipeline is envisaged to be insignificant. In addition, M^G is a big positive constant while $M^G < M$.

linearization of new transmission line term

The term $U_{ybb'}^L(A_{ytb} - A_{ytb'})$ in Eq. 28 is nonlinear. It includes the multiplication of binary variable U by continuous variable A . This bi-linear term can be replaced by auxiliary continuous variable T . This term can be replaced by $-UM \leq T \leq UM$ and $-(1 - U)M \leq (T - A) \leq (1 - UM)$, where M is a big positive constant [56, 57].

$$T_{ybbb'}^L = U_{ybb'}^L(A_{ytb} - A_{ytb'}) \forall y, t, b, b' \quad (67)$$

$$-PF_{bb'} U_{ybb'}^L \leq S_{bb'} S_B T_{ybbb'}^L \leq PF_{bb'} U_{ybb'}^L, \forall y, t, b, b' \quad (68)$$

$$-U_{ybb'}^L M \leq T_{ybbb'}^L \leq U_{ybb'}^L M \forall y, t, b, b' \quad (69)$$

$$-(1 - U_{ybb'}^L)M \leq T_{ybbb'}^L - (A_{ytb} - A_{ytb'}) \leq (1 - U_{ybb'}^L)M \forall y, t, b, b' \quad (70)$$

$$U_{ybb'}^L \leq \bar{U}_{bb'}^L; \forall b, b' \quad (71)$$

$$\sum_y U_{ybb'}^L \leq 1; \forall b, b' \quad (72)$$

$$U_{yy'bb'}^L = U_{ybb'}^L; \forall y, y' \in \{U_{y'bb'}^L > 0, y > y'\}, \forall b, b' \quad (73)$$

$$-PF_{bb'} U_{ybb'}^L \leq S_{bb'} S_B T_{yy'tbb'}^L \leq PF_{bb'} U_{ybb'}^L, \forall y, y', t, b, b' \quad (74)$$

$$-U_{yy'bb'}^L M \leq T_{yy'tbb'}^L \leq U_{yy'bb'}^L M \forall y, y', t, b, b' \quad (75)$$

$$-(1 - U_{ybb'}^L)M \leq T_{ybbb'}^L - (A_{ytb} - A_{ytb'}) \leq (1 - U_{ybb'}^L)M \forall y, t, b, b' \quad (76)$$

Therefore, $T_{ybbb'}^L$ is used in Eq. 28. In addition, Eqs. 34)- 53) are replaced by Eqs. 70- eq:L7.

Figure 3: Network of the illustrative example

The proposed two level energy hub planning is converted into a mixed integer programming by using karush kuhn tucker condition and linearized equations. This model is implemented on two different systems. The first case study include a 6-bus system. The second case study is a multi-carrier energy system encompassing the 24-bus IEEE RTS power grid and 10-node natural gas system.

5. Case study 1: 6-buses system

In this section, is the efficiency of the proposed framework is examined through case study. The case study is a two area power system comprising six buses. The considered network is depicted in Fig 3, which is composed of two areas (north and south) interconnected by two tie-lines.

Required network data associated to existing generating units (type, capacity, location, and ownership), investment options, demands blocks and demands bids can be found in [36]. The capacities of tie-lines are limited to 450 MVA. The planning horizon is assumed to be five years. The annual demand growth and annual interest rate are assumed to be 8.7% and 10%, respectively. It is assumed that

10% of new capacity units are purchased in a contractual framework. Also, firm contract price is assumed to be 33€/MWh. Capacity payment rate is assumed to be 5€/MWh, which are paid to all available units. The contractual volume, the contract price and the capacity payment rate are assumed to be constant over the planning period. Available investment budget is assumed 150M€. Forced outage rate (F.O.R) of new and existing units are assumed to be 0.03 and 0.05, respectively. Regarding to investment by other producers, it is assumed that they select peak technology, and also construct their new units on bus 4. All busses are considered to be candidates for investing new generation capacities.

In this paper, for simplicity, four scenarios are considered for the non-strategic company's investment participating in energy hub market. It is assumed that non-strategic company only invest in generation units. Scenario 1 includes non-investment with 10% probability. Scenario 2 includes 400MW peak investments on bus 4 in the second year of planning with a probability of 50%. Scenario 3 includes 400MW peak investments on bus 4 in the third year of planning with a probability of 25%. Scenario 4, includes 400MW peak investment on bus 4 in the fourth year of planning with a probability of 15%. It is assumed that each new unit consists of two generation blocks and each block is built at half capacity. The operating cost of the first block equals 14.72(€/MWh) and that of the second block equals 15.2(€/MWh). It is assumed that in different markets, the offers of non-strategic units equal the operation cost.

In order to investigate impacts of incentive policies on capacity expansions and economic indices of the market, four policies are defined and examined. Energy only (EO), capacity payment (CP), firm contract (FC) and hybrid (H) (both capacity payment and firm contract) are market designs which have been investigated here. The proposed model has been solved using solver CPLEX under GAMS. In the following the results obtained by simulations of the proposed methodology is analyzed.

Figure. 4 shows the capacity, technology, and location of new units in different markets at different stages of planning. The new units are considered as part of existing new plants in the coming years as shown in the figure. The invested units

Figure 4: Capacity, technology, and location of new units in different markets at different stages of planning

affect not only the market price, but also the economic indicators of market including social welfare, net producer surplus (both strategic and non-strategic), and net consumer surplus. The values of these economic indicators, except for net consumer surplus, are shown in Figure. 5. Figure. 6 shows net consumer surplus based on energy consumption and peak times for different markets at different stages of planning. For greater clarity of market information, this figure is presented both in the original scale and in the scale seen here. Summary of results of generation expansion planning for different markets in the scheduled time is summarized in Table 1. The results of simulation of a 6-bus network are analysed below using Figures 4 to 6 and Table 1.

5.1. Energy only policy

- In the EO policy, the total capacity added by the strategic producer in the planning horizon has been obtained equal to 950MW (450MW peak and 500MW base technologies). Also, distribution of the investment are as the below: 250MW on peak technology in the first year, 500MW on base technology in the second year and 200MW peak technology in the fifth year of the planning period.

Figure 5: Economic indicators of market including: strategic producer's net surplus, nonstrategic producers' net surplus, social welfare, and average market prices for all markets at different stages of planning

Figure 6: Net consumer surplus based on energy consumption and peak times for different markets at different stages of planning

Table 1: SUMMARY RESULTS OF SIX-BUS SYSTEM

Market design	Total capacity added (base, peak) (MW)	Average price (€/MWh)	Total Energy consumed (MMWh)	Total strategic producer profit (M€)	Total Social welfare (M€)	Total strategic producer surplus	Total other producers surplus	Total consumers surplus plus (M€)
Energy only	950 (500,450)	21.65	45.71	96.62	520.95	225.83	202.85	92.23
Capacity payment	3300 (0,3300)	21.63	46.09	410.72	431.12	150.24	186.12	93.43
Firm contract	4350 (0,4350)	21.51	46.09	484.19	555.21	286.75	172.91	95.69
Hybrid	4100 (0,4100)	21.76	46.09	493.1	555.01	292.15	172.96	89.98

452 • According to the above investment, some variations have been observed in the
 453 average annual market price. In addition to affecting on the market price, the
 454 capacity additions have been reflected on the other economic measures, such
 455 as social welfare, consumers' surpluses and producers' surpluses which are
 456 also reported in Table

457 5.2. Capacity payment policy

- 458 • The total capacity added by the strategic producer in the planning horizon
 459 have been obtained equal to 950MW (450MW peak and 500MW base tech-
 460 nologies) and 3300MW (peak technology) for EO and CP policies, respec-
 461 tively. The CP design encourages investment on peak technologies, while
 462 peak and base technologies have been invested in the EO policy.
- 463 • It was also observed that (not reported here) in the CP policy outputs of new
 464 units decrease by 9.85% compared to EO policy. The net surplus of the strate-
 465 gic producer has been decreased by 49.67% with respect to the EO design.
- 466 • Average annual market price (or long term market price over the planning
 467 period) has been obtained equal to 21.63€/MWh and 21.65€/MWh for CP
 468 and EO policies, respectively; which has been decreased by 0.09% compared
 469 to EO policy.
- 470 • The total social welfare is obtained 520.95M€ and 431.12M€ for EO and CP
 471 policies, respectively. In addition, the total consumer surplus is obtained
 472 92.23M€ and 93.43M€ for EO and CP policies, respectively. The total sur-
 473 pluses of the producers has been obtained 428.68M€ and 336.36M€ for EO
 474 and CP policies, respectively. Therefore, although the capacity payment in-
 475 creases both the social welfare and producers' surpluses in the short-term;
 476 this may not be the case in the long term, since both the social welfare and
 477 producers' surpluses have been totally decreased by 17.24% and 21.53%, re-
 478 spectively.

479 5.3. Firm contract policy

- 480 • The strategic producer has totally added 4350MW on his own capacity over
 481 the planning period. It can be seen that because of the contractual price and

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482 contract volume, the capacity additions have been increased with respect to
483 EO policy. Similar to EO design, the average market price fluctuates during
484 the planning period. In this respect, the average price over the planning pe-
485 riod has been obtained equal 21.51(€/MWh), where shows 0.64% reduction
486 with respect to EO policy. Construction of new power plants provides energy
487 for a few part of the demand over the time and thus leads to a decrease in the
488 market price.

- 489 • The total social welfare over the planning period has been obtained equal
490 555.21M€, which shows increasing by 6.58% with respect to EO design. Also,
491 the total consumer surplus over the planning period (around 95.69M€) has
492 been increased by 3.75% compared to EO policy. However, both social welfare
493 and consumer surplus have variations during the planning period. Note that
494 by addition new peak units in FC design, net surplus of producers and social
495 welfare have been increased compared to the EO policy.
- 496 • It can be concluded that the FC policy encourages investing on the peak tech-
497 nologies and also improve social welfare in the long term.

498 *5.4. CP and FC (Hybrid) policy*

- 499 • Investment incentives have totally made the investor to add peak technologies
500 in the system. Also, the annual market price fluctuates during the planning
501 period. Such that the average market price over the planning period has
502 been obtained 21.76€/MWh, which represents increasing by 0.51%, 0.60%
503 and 1.62% with respect to EO, CP and FC designs, respectively. Fig. 7 shows
504 the total energy produced by units in the planning period for different market
505 design.
- 506 • Energy produced by new strategic units in CP, FC and H policies has been
507 increased by 1.53%, 15.15% and 15.94% with respect to EO design, respec-
508 tively. In addition, energy produced by the new strategic units increase in FC
509 and H markets compared to CP market. There is more interest in investing in
510 peak technologies to benefit from investment incentives in all markets. Also,
511 the possibility of investment in base technology is very low in these markets.

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512 Note that a part of the capacity of the new units in FC and H market are sold
513 before the spot market.

- 514 • Energy produced by the existing strategic units has been increased by 1.45%
515 in CP policy with respect to EO design. However, the considered energy in
516 FC and H policies has been decreased by 26% and 27.77% compared to EO
517 policy, respectively.
- 518 • Energy produced by the non-strategic strategic units in CP policy has been
519 increased by 23% compared EO design. However, the considered energy in
520 FC and H policies has been decreased by 5.31% and 7.76% compared to EO
521 policy, respectively.

522 It has been observed that in the case of investment incentives, the strategic
523 producer show a greater willingness to invest earlier. The peak unit is a strate-
524 gic producer's priority to build because of the lower investment and marginal
525 costs. Regarding to the low budget of strategic producer, it seems logical to
526 observe the inclination of constructing a peak unit. Thus, it can be seen that
527 the budget constraints and annual cost payment causes delays and investment
528 incentives enforces the investment.

529 The average market price in demand blocks of the first year is shown in Fig. 8.
530 Nodal prices are the same at all buses at this block because of no deviations
531 in the transmission constraints. Regarding the two levels of each demand
532 block, producer's offers are the same and equal to the clearing price in two
533 levels. Also, it has been observed that market-clearing prices are less than util-
534 ities of demands. Offers of the strategic producer are lower than the market-
535 clearing price over the planning period. Therefore, the market price depends
536 on whether the producers are strategic or non-strategic.

537 **6. Case study 2: 24-bus IEEE RTS power system and 10-node natural gas sys-**
538 **tem**

539 As a second case study, an energy hub system encompassing 24-bus IEEE RTS
540 and 10-node natural gas system is considered. Fig. 9 presents he modified 24-bus

Figure 7: Total energy produced by units in different markets

Figure 8: Average market price in demand blocks in the first year

IEEE RTS. The information about 24-bus IEEE RTS can be found in [58]. Fig. ?? presents the accessible gas suppliers and pipelines configuration related to 10-node natural gas system. The data associated with candidate transmission lines, existing and candidate gas furnace, candidate CHP, as well as natural gas network can be found in [39]. The dynamic energy hub planning is done for 10 years. The annual growth of both electricity and heat demand are envisaged to be 10%. The amount of natural gas demand depends on the amount of fuel gas-fired power plants used in each year. The amount of tax rebate and loan factor for investment in CHP are 10% and 50%, respectively. The Other data are similar to the data used in the 6-bus case study. Candidate transmission lines includes: 6-10, 8-10, 7-8, 8-9, 1-3, 16-17, 11-13, 16-19, 12-23, 15-16, 15-24, and 15-21 as they are specified in Fig. 9. The gas node and electrical bus of candidate CHPs are 6, 5, 4, 10, and 7, 6, 10, 19, 14, and 11, respectively. In addition, their capacities is 50, 50, 50,100, and 50 MW. As another resources to generate heat, candidate gas furnaces are located at gas nodes 4, 5 ,6 ,7, and 10 with the capacity of 500 MMBtu. Furthermore, candidate buses for peak and base generation units include 1,2, 8,13, 18, and 23. The performance of the proposed markets can also be evaluated by metrics like system efficiency, and emissions of pollutants. Emission resulted from power plants can make climate [59]. Efficiency represents equal to total output energy (electrical and thermal energy) with respect to total input energy (electrical energy and fuel). It is noted that 1 MWh=3.14 MMBtu. Emissions of pollutants include emission from CHP, gas furnace, as well as power plants so that each of these components have especial emission rate.

The result for energy hub investment planning for a variety of markets is presented in Table 2. In CP market, the amount of capacity payment is assumed to be 5 (€/MW). In the FC market as a third case, the firm contract volume is envisaged to be 30% of new investment with 10 (€/MW). The two next cases belong to SH market so that the features of CP an FC are similar to the related markets. The budget to invest in for case 5 is 1.12 times more than that of case 4 in SH market. In case 6, 95% is considered for the amount of tax rebate (TR) to invest CHP. The CHP loan (CL) factor in case 7 is 4%. In the next market, tax rebate and CHP loan are

Figure 9: 24-bus IEEE RTS power system

Figure 10: 10-node natural gas system

simultaneously considered to motivate the strategic company to invest in CHP. In two last cases, all energy hub investment incentives are implemented for the short term and long term market. The second and third column of table 2 present MW generation investment (GI) and the number of invested transmission lines (TL) in each year accordingly. The next two columns provide MW CHP investment (CI) and MMBtu gas furnace investment (GF) in each year, respectively. It is worth to mention that the year in which the component is installed is defined inside the bracket.

In the EO market, 500 MW generation unit is invested in the tenth year. Also, 8 transmission lines in the first year and 1 transmission line in the fourth year are installed in the power grid resulting from power congestion in existing transmission system, an increase of existing generation capacity. Transmission lines 6-10, 11-13, 12-23, 15-16, 15-21, 15-24, 16-17, and 16-19 are added to the existing transmission system in the first year while transmission line 7-8 are invested in the fourth year. In addition to power system investment, a 50 MW CHP and a 500 MW gas furnace are installed in the third and fourth year, accordingly. CHP is invested in gas node 4 and electrical bus 19. In the CP market, investment in generation units has increased by 500 MW compared to EO market. Available new capacity during the whole planning duration (ACIPD) is equal to 5000 MW ($500 \times 7 + 500 \times 3$) [60]. As a result, CP motivates noticeably the strategic company to invest in generation units. In addition, because of an increase in generation of power plants, emissions in CP market has increased by 4.89%. The total electricity social welfare has increased by 0.12% compared to that of EO market while heat and gas social welfare has not change. In the FC market, 750 MW generation unit is invested in the first year; consequently, ACIPD in this market is increased by 7000 MW and 1500 MW with respect to EO and CP markets, respectively. The energy hub social welfare has increased by 1.86 %; likewise, the amount of system efficiency and emissions of pollutants have increased by 0.41% and 9.96% compared to those of EO market. As it is clear, FC is an appropriate policy to motivate to invest in new unit although the amount of emission has increased. This is a consequence of the fact that the only the first level aim of the proposed model is to maximize the profit of investors while there can be a trade-off among profit, efficiency, and emissions. In addition,

Table 2: Summary result OF energy hub system including 24-buses IEEE RTS power system and 10-node natural gas system

Market	GI(year)	TL(year)	CI(year)	GF(year)	SW^E (10^{10}€)	SW^H (10^9€)	SW^G (10^{10}€)	SW (10^{10}€)	efficiency	emission (10^{10}KG)
EO	500(10)	8(1)- 1(4)	50(3)	500(4)	1.566	3.10	2.95	4.83	0.480	2.818
CP	500 (4) - 500(8)	7(1)	50(3)	500(4)	1.568	3.10	2.95	4.83	0.477	2.956
FC	750(1)	7(1)	50(3)	500(5)	1.655	3.104	2.95	4.92	0.482	3.092
SH 1	750(1)	7(1)	50(3)	500(5)	1.655	3.104	2.95	4.92	0.482	3.092
SH 2	1000 (1)- 500 (6)- 1000 (7)- 1000 (8)- 1500 (9)- 3500(10)	7 (1)	50 (3)	500 (5)	1.700	3.104	2.95	4.97	0.480	3.282
TR	500(7)- 500(9)	7(1)- 1(9)	200(1)	500(5)	1.555	3.021	2.95	4.81	0.476	2.803
CL	-	7(1)	200(1)	500(5)	1.515	3.021	2.95	4.77	0.472	2.803
TR+CL	500(7)- 500(9)	7(1)- 1(8)	200(1)	500(5)	1.557	3.021	2.95	4.81	0.477	2.895
All	500(1)- 1000(3)- 500(5)	6(1)	200(1)	500(5)	1.700	3.021	2.95	4.96	0.482	3.422
All 2	750(5)- 1000(2)- 500(3)- 500(4)- 500(7)- 250(10)	7(1)	200(1)	500(5)	1.818	3.021	2.95	5.07	0.494	3.506

in the FC market, 7 lines are added to the power grid which is less than the number of the new transmission lines in the EO market. The reason is that the investor tends to use the budget in order to invest in generation unit to benefit of advances of firm contract. Also, gas furnace is invested in the fifth year instead of the forth year in EO and CO markets. The result of SH policy in the energy hub system is the same as that of FC market while the budget is the same. By increasing the budget by 12% in the SH market, the whole new capacity is 8500 MW. As a result, the firm contract and capacity payments motivate the investors considerably so that energy hub social welfare has increased by 1.01 %. The system efficiency has decreased by 0.414%, emissions resulting from pollutants, on the other hand, has increased by 6.14%.

In the TR market, 4 CHP units are invested in the first year. The installed capacity is 200 MW. ACIPD related to CHP is 2000 MW. As a result, it has increased by 1600 MW compared to that of EO, CP, FC, and SH markets. The energy Hub social welfare has degraded by a decrease in the electrical social welfare influenced by high investment cost of CHP. In the CL market, there is no investment in generation unit while ACIPD is the same as that of TR market. The amount of emissions in the both TR market and CL market has decreased compared to other markets by using new CHP units in the generation. When TR and CL are simultaneously considered, the strategic company invests in 1000 MW generation units. When all investment incentives are considered, the strategic company invests in 2000 MW generation units, 1000 MW CHP, 500 MMBtu gas furnace, and 6 transmission lines. The energy hub social welfare, efficiency and emissions have increased compared to those of TR and CL markets. By increasing the budget by 12%, the investment in generation units has increased by 1500 MW. The efficiency is equal to 49.4% which is the highest level of efficiency in all markets; likely-wise, the energy hub social welfare in this market is the highest level of social welfare in all markets.

Tables 3-4 present the result of GI (MW), MW invested capacity in planning duration (ICIPD), ASIPD (MW) with respect to change of amount capacity payment and firm contract rate in the energy hub system, respectively. According to the results, ASIPD in both CP and FC market has increased while the ICIPD may not have