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An integrated model for assessing electricity retailer's profitability with demand response

Athanasios S. Dagoumas [a,*], Michael L. Polemis [b]

[a] University of Piraeus, School of Economics, Business and International Studies, Energy & Environmental Policy Lab, PC 18532 Piraeus, Greece
[b] University of Piraeus, Department of Economics, Piraeus, Greece

HIGHLIGHTS

- Integration of Unit-Commitment problem with econometric models.
- Quantification of demand response' effect on the fluctuations of spot prices, based on their short-term price elasticities.
- Identification of periods with high price margins for electricity retailers.
- Provision of price signals on the profitability of electricity retailers and.
- Provision of useful insights into the risk of electricity retailers with price-responsive consumers.

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ABSTRACT

This paper introduces a model that integrates a Unit Commitment (UC) model, which performs the simulation of the day-ahead electricity market, combined with an econometric model that estimates the income and price elasticities of electricity demand. The integrated model is further extended to estimate the retailers' profitability with demand responsive consumers. The applicability of the proposed model is illustrated in the Greek day-ahead electricity market. The model is designed to identify the effects of demand responsiveness to the fluctuations of spot prices, based on their short-term price elasticities. It provides price signals on the profitability of retailers/demand aggregators, when forming their tariffs. We argue that the non-linearity between demand response and evolution of wholesale price, inherits risk for retailers. This finding could lead even to losses for some time periods, affecting strongly their viability. The model provides useful insights into the risk of retailers from their price responsive customers and therefore acts as a pivotal study to policy makers and government officials (i.e. regulators, transmission and distribution system operators) active in the electricity market.

1. Introduction

The evolution of smart networks is expected to be radical over the next years [1]. Integration of metering, sensing and actuation systems, is likely to optimize the whole energy consumption, by eliminating the needs for new infrastructure, as the efficiency, reliability and economics of the power systems can be improved. We are not far away from a period with consumers reshape their consumption patterns, especially for energy, based on real-time price signals. The price responsiveness of final consumers has been extensively examined in the past, mainly through econometric studies that estimated the income and price elasticities on energy demand. A review paper [2] aggregated a number of econometric studies, for countries of different geographical and economic backgrounds, aiming at identifying the relationship of electricity consumption with its determinants. The empirical evidence in a study over 100 countries [3] estimated their correlation. However, the variation in the results, concerning the magnitude of the elasticities, but as well as the causality among them may be attributed to variable selection, model specifications, time periods of the studies, different institutional, structural frameworks in the countries examined, and the econometric approaches undertaken [4,5]. However, those studies have investigated the price responsiveness of electricity consumers, based on non-dynamic electricity prices and neglecting demand response to real-time market prices.

In real electricity markets, the price responsiveness might be more dynamic. Therefore, the demand aggregators who act as demand representatives in the wholesale market of large industrial firms, residential and commercial customers are in high risk in case their customers respond to the fluctuations of real-time market prices. This paper aims to assess how the profitability and the risk

* Corresponding author.
E-mail address: dagoumas@gmail.com (A.S. Dagoumas).

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Nomenclature

Acronyms

ADMIE Independent Power Transmission System Operator
LAGIE Hellenic Electricity Market Operator
GAMS General Algebraic Modelling System
MILP Mixed Integer Linear Programming
RAE Regulatory Authority of Energy
RES Renewable Energy Sources
SMP System Marginal Price
IMP Imbalance Marginal Price
UCP Unit Commitment Problem

Sets

$g \in G^{res}$ set of renewable units (not including hydro units)
$g \in G^{s}$ set of units $g \in G$ that are installed in subsystem $s \in S$
$g \in G^{th}$ set of thermal units
$g \in G^{z}$ set of units $g \in G$ that are (or can be) installed in zone $z \in Z$
$g \in G$ set of all units
$c \in C$ set of all customer types (industrial, residential, commercial)
$r \in R$ set of all retailers participating in the electricity market
$n \in N^{s}$ set of interconnected power systems $n \in N$ with subsystem $s \in S$
$n \in N^{z}$ set of interconnected power systems $n \in N$ with zone $z \in Z$
$n \in N$ set of interconnected power systems
$w \in W$ set of start-up types {hot, warm, cold}
$z \in Z$ set of zones

Parameters

$AF_{g,z,t}$ availability factor of each unit $g \in G^{res}$ in zone $z \in Z$ and hour $t \in T$ (p.u.)
$CB_{g,b,t}$ marginal cost of block $b \in B$ of the energy offer function of each unit $g \in G^{hth}$ in hour $t \in T$ (€/MW)
$CEP_{n,b,t}$ marginal export bid of block $b \in B$ to interconnection $n \in N$ in hour $t \in T$ (€/MW)
$CIP_{n,b,t}$ marginal cost of block $b \in B$ of the imported energy offer function from interconnection $n \in N$, in hour $t \in T$ (€/MW)
CL_f capacity range- f of the proposed interconnector between the mainland (interconnected) and the autonomous power system
$CPM_{e,b,t}$ marginal bid of block $b \in B$ of pumped storage unit $h \in H$ in hour $t \in T$ (€/MW)
$D_{s,t}$ power load of subsystem $s \in S$, in hour $t \in T$ (MW)
$EP_{n,b,t}$ quantity of capacity block $b \in B$ of each energy export interconnection $n \in N$ in hour $t \in T$ (MW)
$FL_{s,s',t}$ Upper bound of the flow from subsystem $s \in S$ to subsystem $s' \neq s \in S$ in hour $t \in T$ (MW)
FSR_t^{down} system requirements in fast secondary-down reserve in hour $t \in T$ (MW)
FSR_t^{up} system requirements in fast secondary-up reserve in hour $t \in T$ (MW)
IC_{res}^{int} installed capacity of renewables in the mainland (interconnected) power system
$IP_{n,b,t}$ quantity of capacity block $b \in B$ of each power import interconnection $n \in N$ in hour $t \in T$ (MW)
$L_{z,t}$ injection losses coefficient in zone $z \in Z$ and hour $t \in T$ (p.u.)
$NP_{g,t}$ fixed (non-priced) component of the energy offer function of each unit $g \in G$ in hour $t \in T$ (MW)
$PCB_{g,b,t}$ Power capacity block $b \in B$ of the energy offer function of unit $g \in G^{hth}$ in hour $t \in T$ (MW)
$PC_{g,t}$ available power capacity of unit $g \in G$ in hour $t \in T$ (MW)
$PMB_{e,b,t}$ quantity of capacity block $b \in B$ of pumped storage unit $h \in H$ in hour $t \in T$ (MW)
P_g^{min} technical minimum of each unit $g \in G^{hth}$ (MW)
P_g^{max} Maximum power output of each unit $g \in G^{hth}$ (MW)
$P_g^{max,sc}$ maximum power output (when providing secondary reserve) of each unit $g \in G^{hth}$ (MW)
P_g^{max} maximum power output (dispatchable phase) of each unit $g \in G^{hth}$ (MW)
$P_g^{min,sc}$ minimum power output (when providing secondary reserve) of each unit $g \in G^{hth}$ (MW)
P_g^{min} minimum power output (dispatchable phase) of each unit $g \in G^{hth}$ (MW)
P_g^{soak} power output of each unit $g \in G^{hth}$ when operating in soak phase (MW)
PR_g maximum contribution of unit $g \in G^{hth}$ in primary reserve (MW)
PR_t^{up} system requirements in primary-up reserve in hour $t \in T$ (MW)
SR_i maximum contribution of unit $g \in G^{hth}$ in secondary reserve (MW)
SR_t^{down} system requirements in secondary-down reserve in hour $t \in T$ (MW)
SR_t^{up} system requirements in secondary-up reserve in hour $t \in T$ (MW)
TR_g^{nsp} maximum contribution of unit $g \in G^{hth}$ in non-spinning tertiary reserve (MW)
TR_g^{sp} maximum contribution of unit $g \in G^{hth}$ in spinning tertiary reserve (MW)
TR_t system requirements in tertiary reserve in hour $t \in T$ (MW)
$PRO_{g,t}$ price of the primary energy offer of each unit $g \in G^{hth}$, in hour $t \in T$ (€/MW)
$SRO_{g,t}$ Price of the secondary range energy offer of each unit $g \in G^{hth}$, in hour $t \in T$ (€/MW)
R_g^{down} ramp-down rate of unit $g \in G^{hth}$ (MW)
R_g^{sc} ramp rate of unit $g \in G^{hth}$ when providing secondary reserve (MW)
R_g^{up} ramp-up rate of unit $g \in G^{hth}$ (MW)
SDC_g shut-down cost of each unit $g \in G^{hth}$ (€)
T_g^{htw} non-operational time of unit $g \in G^{hth}$ before going from hot to warm standby condition (h)
T_g^{desyn} desynchronization time of unit $g \in G^{hth}$ (h)
T_g^{down} minimum down time of unit $g \in G^{hth}$ (h)
T_g^{past} extended time period in the past (greater than the higher cold reservation time of all thermal units) (h)
T_g^{rdn} non-operational time (after being shut-down) of unit $g \in G^{hth}$ (h)
$T_g^{soak,w}$ type-w soak time of unit $g \in G^{hth}$ (h)
$T_g^{sync,w}$ type-w synchronization time of unit $g \in G^{hth}$ (h)
T_g^{up} minimum up time of unit $g \in G^{hth}$ (h)
T_g^{wtc} non-operational time of unit $g \in G^{hth}$ before going from warm to cold standby condition (h)
CAP maximum allowed price for priced energy offers
$MARGIN_{s,r,c,t}$ margin of the retailer $r \in R$, from the tariffs he provides to customer type $c \in C$ in subsystem $s \in S$ and hour $t \in T$
$TOL_{s,c,t}$ tolerance for the responsive customers to respond to price differences among the SMP and the tariff provided by the retailers, for customer type $c \in C$ in subsystem $s \in S$ and hour $t \in T$

GDP_t Gross Domestic Product, measured in Euro is expressed in constant 2005 prices, for all hours $t \in T$ of a year (Euro)
$EMPL_t$ total number of persons employed in the total economy for all hours $t \in T$ of a year (thousands)
HDD_t heating degree days for all hours $t \in T$ of a year
CDD_t cooling degree days for all hours $t \in T$ of a year
$PRICE_t$ low voltage residential electricity price from the dominant retailer Public Power Corporation, deflated by the Consumer Price Index, in hour $t \in T$ (Euro/MW h)
$LFOIL_t$ light fuel oil price for the residential sector, deflated by the Consumer Price Index, in hour $t \in T$ (Euro/1000 L)

Continuous variables
$exb_{n,b,t}$ cleared quantity of power capacity block $b \in B$ exported to interconnected system $n \in N$ in hour $t \in T$ (MW)
$ex_{n,m,t}$ total energy withdrawal (exports) to interconnected system $n \in N$ in hour $t \in T$ (MW)
$fr2^{down}_{g,t}$ contribution of unit $g \in G^{hth}$ in fast secondary-down reserve in hour $t \in T$ (MW)
$fr2^{up}_{g,t}$ contribution of unit $g \in G^{hth}$ in fast secondary-up reserve in hour $t \in T$ (MW)
$f_{s,s',t}$ corridor power flow from subsystem $s \in S$ to $s \neq s' \in S$ in hour $t \in T$ (MW)
$imb_{n,b,t}$ cleared quantity of power capacity block $b \in B$ imported from interconnected system $n \in N$ in hour $t \in T$ (MW)
$im_{n,t}$ total energy injection (imports) from interconnected system $n \in N$ in hour $t \in T$ (MW)
$im^{net}_{n,t}$ net energy injection (imports) to interconnected system $n \in N$ in hour $t \in T$ (MW)
$pb_{g,b,t}$ quantity of power capacity block $b \in B$ of unit $g \in G^{hth}$, dispatched in hour $t \in T$ (MW)
$p_{g,t}$ energy injection (generation) from unit $g \in G^{hth}$ in hour $t \in T$ (MW)
$p^{desyn}_{g,t}$ power output of unit $g \in G^{hth}$ when operating in the desynchronization phase in hour $t \in T$ (MW)
$p^{net}_{g,t}$ net energy injection from unit $g \in G^{hth}$ in hour $t \in T$ (MW)
$p^{soak}_{g,t}$ power output of unit $g \in G^{hth}$ when operating in the soak phase in hour $t \in T$ (MW)
$pmb^{pum}_{e,b,t}$ cleared quantity of block $b \in B$ of pumping unit $h \in H$ in hour $t \in T$ (MW)
$pmb^{pum}_{e,t}$ total cleared quantity of pumping unit $h \in H$ in hour $t \in T$ (MW)
$CONEL_{s,t}$ electricity consumption for the residential sector in subsystem $s \in S$ and hour $t \in T$
$TARIFF_{s,c,t}$ tariff provided by the retailers to customer of type $c \in C$ in subsystem $s \in S$ and hour $t \in T$
$SMP_{s,t}$ system marginal price of the wholesale day-ahead electricity market in subsystem $s \in S$ and hour $t \in T$
$IMP_{s,t}$ imbalance marginal price of the wholesale day-ahead electricity market in subsystem $s \in S$ and hour $t \in T$
$D'_{s,r,c,t}$ power load measured for customer type $c \in C$ of the retailer $r \in R$ in subsystem $s \in S$, in hour $t \in T$ (MW)
$D'_{s,c,t}$ Power load measured for customer type $c \in C$ in subsystem $s \in S$, in hour $t \in T$ (MW)
$D'_{s,t}$ power load measured in subsystem $s \in S$, in hour $t \in T$ (MW)
$REVENUE_{s,r,t}$ revenue of the retailer $r \in R$ from their customers in subsystem $s \in S$ and hour $t \in T$ (MW)
$REVENUE'_{s,t}$ revenue of all retailers from their tariff responsive customers in subsystem $s \in S$ and hour $t \in T$ (MW)
$REVENUE'_{s,r,t}$ revenue of the retailer $r \in R$ from its tariff responsive customers in subsystem $s \in S$ and in hour $t \in T$ (MW)

of electricity retailers are affected by price-responsive consumers. It quantifies the profitability and risk of electricity retailers by developing an integrated model, integrating a unit commitment model and an econometric model, which is applied in case of the Greek power system. The Unit Commitment (UC) problem identifies the units that will operate in the day-ahead electricity market based on an optimization approach that considers their variable costs, their bidding strategy, the ancillary services and other technical criteria required by the Transmission System Operator (TSO). The econometric model estimates the income and price elasticities of electricity demand. Those elasticities are introduced in the integrated model, which is further extended to estimate the retailers' revenue with demand responsive consumers.

The literature concerning the profitability of electricity retailers and demand response is extending rapidly over the last years, as it concerns an important problem in real energy markets. A resent paper [6] addressed the associated trade-off between Information and Communications Technology (ICT) deployment of demand response systems and economic benefits for an electricity retailer. It concluded that electricity retailers can achieve a profitable setting by restricting smart meter roll-out to large customers. Another paper [7] analysed the interactions between wholesale, forward and retail markets, concluding that vertical integration is superior to forward hedging when retailers are highly risk averse. A paper [8] provided evidence from a dynamic pricing experiment, showing that residential customers' response to hourly price signals were similar to the response to price signals with much longer duration. A recent paper [9] measured demand responses to the Ontario wholesale electricity prices using market indices. It concluded that demand response to hourly price movements is small and statistically significant. Moreover, that price elasticities exhibit large variations over the times of days/seasons, taking high values during the economic crisis. A recent paper [10] developed an analytical equilibrium model to quantify the effect of deploying demand response on social welfare and energy trade. The paper demonstrates the existence of an optimal area for the price signal in which demand response enhances social welfare. This optimal area is negatively correlated to the degree of competitiveness of generation technologies and the market size of the system.

Demand response resources can have noticeable impacts on the electricity markets' operation. A recent paper [11] found that demand response mechanisms have the potential to decrease electricity prices, causing significant diversifications on social welfare, in favour of the consumers. Lohmann and Rebennack [12] presented a long-term power generation expansion planning model, integrating an hourly time resolution, multi-period investment and retirement decisions, transmission constraints, start-up restrictions and short-term demand response. The model was applied for developing a new approach to generalized Benders decomposition and directly calculating all necessary optimal primal and dual variable values, referred to as the calculation-based method. Forrest and MacGill [13] employed econometric analysis techniques to evaluate the impact of wind power generation on electricity prices as well as on gas- and coal-fired generation. The results show a negative correlation between wind output and electricity price and that natural gas-fired power generation is mainly affected by increased wind output, while coal-fired power generation is less affected by that evolution. Clò et al. [14] made an analysis of the Italian wholesale power market and found that over the period 2005–2013, a rise of 1 GW h in the hourly average of daily wind and solar power generation has, on average, reduced wholesale electricity prices by respectively 2.3€/MW h and 4.2€/MW h and has made them more volatile.

A robust practice to identify the effect of demand response of the real markets is to incorporate it in the unit commitment problem, which is one of the main targets and contributions of this paper. In a recent paper [15], a thermal unit commitment program considered a demand response system, constituting of electric vehicle (EV) and heat pump (HP) in a smart house. Magnago et al. [11], examined the impact of demand response resources on unit commitment and dispatch in a day-ahead electricity market. It concluded that demand response can exert downward pressure on electricity prices, causing significant implications on social welfare. Downward et al., [16] developed a model for assessing the retailers entrance in the electricity market, providing evidence on how the behaviour of firms change with risk-aversion.

Vlachos and Biskas [17] modelled the incorporation of demand response bids within a real-time balancing market. The proposed model is useful for designing future real-time balancing markets, incorporating the active participation of price-responsive demand. Arasteh et al. [18] investigated the impact of Demand Response Resources (DRRs) on power markets, showing significant reductions in operating costs. Liu and Tomsovic [19] proposed a robust unit commitment model to minimize the generalized social cost, taking into account of the uncertainty of the price elasticity of electricity demand. To model the behaviour of consumers, it explored the price elasticity of demand, considering that it is not precisely known and may vary greatly with operating conditions and types of customers. Ghazvini et al. [20] developed a multi-objective model for scheduling of short-term incentive-based demand response programs offered by electricity retailers. The multi-objective problem aims at minimize peak demand, in favour of retailers, considering the reshaping of customers' consumption in response to financial incentives. Boroumand et al. [21] analyse the market risks faced by electricity retailers. Using VaR and CVaR risk measures, they compare different intra-day portfolios of hedging, demonstrating the superior efficiency of intra-day hedging over daily hedging. Nojavan et al. [22] provided an optimal stochastic energy management for electricity retailers, based on determining the selling price under smart grid environment in the presence of demand response program. Zugno et al. [23] developed a bi-level model for electricity retailers' participation in a demand response market environment. Another model [1] allows the determination of the dynamic price-signal delivering maximum retailer profit and the optimal load pattern for consumers under this pricing. Mahmoudi et al. [24] proposed a new demand response scheme for electricity retailers, which is modelled as an energy resource of electricity retailers. The feasibility of the problem is assessed using a realistic case within the Australian National Electricity Market, where the outcomes indicate its usefulness for retailers, particularly for the conservative ones. Oadran et al. [25] examined the benefits of demand-side response in combined gas and electricity networks, Combined Gas and Electricity Networks expansion model. Wang et al. [26] formulated a real-time demand response framework and a model for a smart distribution grid, which is optimized in a distributed manner with the Lagrangian relaxation method. Concerning the Greek system, several studies have investigated energy demand relationship with economic growth and prices. A recent work from the authors [27] investigated the causality between the electricity demand and the economic growth in a multivariate framework, but as well as the dynamic interactions between the electricity consumption and its main determinants. Using cointegration techniques and vector error correction model in order to capture short-run and long-run dynamics, the authors concluded in the long-run electricity demand appears to be price inelastic and income elastic, while in the short-run the relevant elasticities are below unity. Bakirtzis et al. [28] developed a multiple time resolution unit commitment model for short-term operations scheduling under high renewable penetration, demonstrating its application to the Greek power system. Andrianesis et al. [29] developed a Medium-Term Unit Commitment (MTUC), by extending the unit commitment problem to a longer horizon of several days, and keeping only the solution for the next day as binding (rolling horizon). Koltsaklis and Georgiadis [30] developed a multi-period, multi-regional generation expansion planning model incorporating unit commitment constraints, while Koltsaklis et al. [31] developed a mid-term market based power system planning model, incorporating a unit commitment model. The model is used to identify the effect of interconnections on the power mix and the day-ahead prices.

This paper describes a generic Mixed Integer Linear Programming (MILP) model that integrates a Unit Commitment (UC) model, which performs the simulation of the Day-Ahead Electricity Market, combined with an econometric model that estimates the income and price elasticities of electricity demand. The integrated model is further extended to estimate the retailers' revenue with demand responsive consumers. The selection of the UC problem, lies in the fact that unit commitment is a more robust modelling approach for electricity price forecasting [32], compared to alternative ones, i.e. artificial neural networks, auto-regression models or econometric approaches, as it incorporates the technical characteristics of each power system. Considering the presence of binary variables, UC problem is formulated as a MILP model. Moreover, the quantification of price elasticities is usually implemented in the literature through econometric approaches. The main contributions of the paper are: (a) integration of Unit-Commitment problem with econometric models, (b) quantification of demand response' effect on the fluctuations of spot prices, based on their short-term price elasticities, (c) identification of periods with high price margins for electricity retailers, (d) provision of price signals on the profitability of electricity retailers and (e) provision of useful insights into the risk of electricity retailers with price-responsive consumers.

2. The model

Methodologically, the current work constitutes an integrated approach which combines a unit commitment model (at an hourly level) with an econometric model for identifying the short-term price elasticity of electricity demand. This approach is based on previous works [31,33], which presented a market-based medium-term power systems planning model. This work is further extended to incorporate demand response, based on a previous work [27] that estimated the short-term income and price elasticities of electricity demand. The integrated model is further extended to estimate how the retailers' profitability is affected from the demand flexibility of their customers.

The problem to be addressed in this work is concerned with the hourly energy balance of a specific power system including the optimal dispatch of power generating units (unit commitment problem), while estimating how the incorporated demand response affects the retailers' revenues. The problem under consideration is defined as follows:

- The scheduling period concerns a daily period, including 24 hourly time steps $t \in T$:.
- The UCP model, based on previous works [31,33], identifies the optimum dispatch of the power units in each subsystem of the power system, towards meeting electricity demand requirements in each subsystem and each time period $D_{s,t}$, as well as meeting ancillary services requirements in each time period, namely: primary-up reserve, secondary-up, secondary-down,

fast secondary-up, fast secondary-down and tertiary reserve requirements: PR_t^{up}, SR_t^{up}, SR_t^{down}, FSR_t^{up}, FSR_t^{down} and TR_t. respectively.

- There exist different types of generating units in each subsystem $g \in G^s$:, namely: hydroelectric, thermal and renewable units. The renewable units, as mandatory hydro and commissioning units, are submitting non-priced energy offers, so their dispatch depends on their spatial availability factor, while the hydro, thermal units and imports form the interconnected systems submit priced energy offers with several capacity blocks. All those energy offers are matched with load declarations from load representatives, such as retailers, power exports $EP_{s,b,t}$ to other interconnected systems and pumping load $PMB_{s,b,t}$.
- The retailer $r \in R$ that participate in the market have a revenue $REVENUE_{s,r,t}$., which is related to the demand they represent $D_{s,r,t}$, the price $SMP_{s,t}$ they are buying in the wholesale market and the tariff $TARIFF_{s,r,c,t}$ they provide to their consumers, for each subsystem $s \in S$ and customer type $c \in C$. In order to eliminate their risk from their participation in the day-ahead market, the retailers provide tariffs, linked to the System Marginal Price $SMP_{s,t}$, estimated by the solution of the wholesale day-ahead market, plus a margin $MARGIN_{s,r,c,t}$ for the retailers, depending on the customer type $c \in C$.
- The electricity demand is considered to be responsive to price signals. The final consumers respond to fluctuations of the $SMP_{s,t}$, when a tolerance level $TOL_{s,c,t}$ is activated for a customer type $c \in C$. This tolerance concerns the percentage of change between the $TARIFF_{s,r,c,t}$ and the $SMP_{s,t}$. Practically, when final consumers find a price spike, positive or negative, where they respond by decreasing or increasing respectively their consumption.
- The demand response $DR_{s,t}$ of the consumers, lead to actual measured demand $D'_{s,t}$, different from the demand $D_{s,t}$ they bought in the wholesale market. This demand response, leads to the estimation of an Imbalance Marginal Price $IMB_{s,t}$ by the TSO. This price is used by the TSO to estimate the debit/credit that retailers have to provide for the demand response $DR_{s,t}$, which is equal to the difference $D'_{s,t}$-$D_{s,t}$.
- Therefore, the retailers have an updated $REVENUE'_{s,r,t}$, which incorporates the risk of the demand response $DR_{s,t}$. The trade-offs between the demand response, the tolerance for responding, the margin of the retailers, the differences between SMP and IMP identify the profitability of the retailers.

3. Mathematical formulation

3.1. Objective function

The proposed objective function is based on the short-term market operation, namely the minimization of the total annual operational cost of the studied power system at 1 daily period. Therefore, the model's objective function includes: (i) marginal production cost of the power units incorporating fuel cost, variable operating and maintenance (O&M) cost, and CO_2 emission allowances cost, (ii) power imports cost, (iii) power exports revenues, (iv) pumping load revenues, (v) units' shut-down cost and (vi) reserves provision cost as represented by Eq. (1).

$$
\begin{aligned}
\boldsymbol{Min}\ Cost^{daily} = & \overbrace{\sum_{u\in(U^{hth}\cap U^z)}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(CB_{u,z,b,t}\cdot PEO_{u,z,b,t}\cdot L_{z,t})}^{\text{Marginal production cost}} \\
& + \overbrace{\sum_{n\in N^z}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(ICB_{n,z,b,t}\cdot IEO_{n,z,b,t}\cdot L_{z,t})}^{\text{Power imports cost}} \\
& - \overbrace{\sum_{n\in N^z}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(ECB_{n,z,b,t}\cdot EEO_{n,z,b,t})}^{\text{Power exports revenues}} \\
& - \overbrace{\sum_{e\in E^z}\sum_{z\in Z}\sum_{b\in B}\sum_{t\in T}(PMCB^{pum}_{e,z,b,t}\cdot PMEO_{e,z,b,t})}^{\text{Pumping load revenues}} \\
& + \overbrace{\sum_{u\in U^{hth}}\sum_{t\in T}(x^{sd}_{u,t}\cdot SDC_u)}^{\text{Shut-down cost}} \\
& + \overbrace{\sum_{u\in U^{hth}}\sum_{z\in Z}\sum_{t\in T}\left[(PR^{up}_{u,z,t}\cdot PRO_{u,z,t})+(SR^{up}_{u,z,t}+SR^{down}_{u,z,t})\cdot SRO_{u,z,t}\right]}^{\text{Reserves provision cost}}
\end{aligned}
\tag{1}
$$

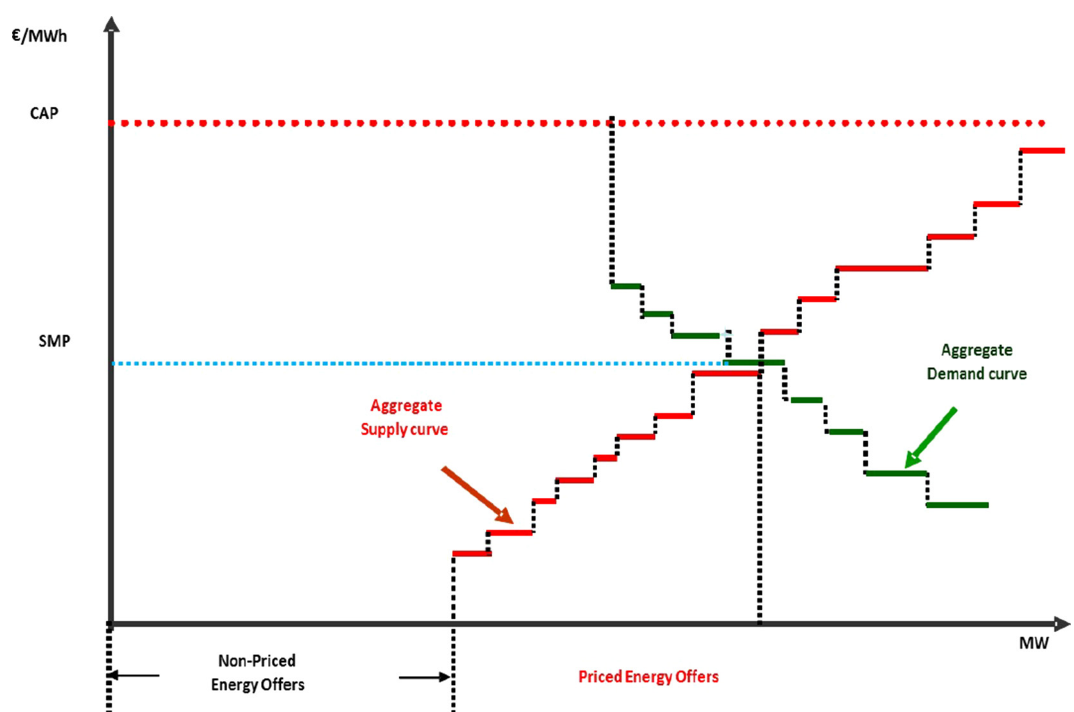

Fig. 1. Determination of System Marginal Price (SMP), as the crossroad of aggregate Supply and Demand curves (Euro/MW h).

The minimization of the objective function leads to the estimation of the System's Marginal Price $SMP_{s,t}$ which is defined as "the price that all electricity suppliers (e.g., producers, importers) are going to be paid and all power load representatives (e.g., exporters, large consumers) are going to pay" [31]. Fig. 1 represents the determination of System Marginal Price (SMP), as the crossroad of aggregate Supply and Demand curves.

3.2. Model constraints

3.2.1. Operational cycle' constraints of unit commitment

The typical operational cycle of a hydro or thermal unit $u \in U^{hth}$ is presented in Eqs. (2)–(16) of a previous work [33], which concerns the constraints of start-up decision, synchronization, soak, and desynchronization, as well as the constraints of minimum up and down times.

3.2.2. Energy offer constraints

Eq. (2) describes the power output of each unit $u \in U^{hth}$ being divided into two parts: (i) fixed (non-priced) component including mandatory hydro power injection and/or hydrothermal power injection from units operating under commissioning status in each time period $NP_{u,z,t}$, for which they submit non priced energy offer ($NPEO_{u,z,t}$), and (ii) priced component based on the energy offer per power capacity block (energy offer function) of each unit $u \in U^{hth}$ in each time period ($CB_{u,z,b,t}$) for which they submit priced energy offer ($PEO_{u,z,t}$). Power injection provided by renewable energy technologies is non-priced, based on the availability factor of each renewable energy resource (e.g., wind, solar) in each zone and time period and provided by constraints (3). Constraints (4) define that the portion of each block $b \in B$ of each existing hydrothermal unit's energy offer function being dispatched in each time period, $CB_{u,z,b,t}$, must not exceed the size of the corresponding step of unit's energy offer function.

$$P_{u,z,t} = NP_{u,z,t} + \sum_{b \in B} CB_{u,z,b,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad t \in T \tag{2}$$

$$P_{u,t} = \sum_{z \in Z} AF_{u,z,t} \cdot NCAP_{u,z,t} \qquad \forall u \in U^{res}, \quad z \in Z, \quad t \in T \tag{3}$$

$$CB_{u,z,b,t} \leqslant NCAP_{u,z,b,t} \qquad \forall u \in U^{hth}, \quad b \in B, \quad t \in T \tag{4}$$

The priced energy offer is linked to the variable cost of a unit, as shown in Eq. (5). In the variable cost, a strategy term is added, which concerns the margin the unit is pursuing from its energy offer. This strategy term $STR_{u,z,b,t}$ can have a linear form. For this model, as the target is overall energy system cost minimization, this term is set to zero, which practically means that it does not focus, by incorporating relevant strategies, on the producers aim to maximize their profits.

Moreover, the binary phase of the model, especially concerning capturing the different states of the units to satisfy their techno-economic characteristics and system requirement i.e. ancillary services, might lead to solutions with revenue losses for producers. This is the reason why, supplementary mechanisms, such as the cost recovery mechanisms or balancing markets, are established in several markets. This is however not treated in the model, as it concerns a different problem, maximization of profits from market participants. Even for the retails, which is the focus of the paper, we don't aim at maximizing their profits, by creating a relevant objective function, but to identify their revenues and risks in case of representing price responsive consumers, as part of the overall energy system cost minimization. This approach, described in Section 3.3, represents a more realistic assessment of their risks in a real market.

Eq. (6) presents the variable cost of a unit $VC_{u,z,t}$, which incorporates the fuel cost $FC_{u,z,t}$, the CO2 emission rights cost $CO2_{u,z,t}$ and the rest operational & maintenance costs $OMC_{u,z,t}$. The latter category, as son in Eq. (7) includes the primary materials costs $PMC_{u,z,t}$ (besides the fuel cost) and the maintenance costs $MC_{u,z,t}$ (besides the scheduled maintenances).

$$PEO_{u,z,b,t} = VC_{u,z,t} + STR_{u,b,z,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad t \in T \tag{5}$$

$$VC_{u,z,b,t} = FC_{u,z,b,t} + CO2_{u,z,t} + OMC_{u,z,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad b \in B, \quad t \in T \tag{6}$$

$$OMC_{u,z,t} = PMC_{u,z,t} + MC_{u,z,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad t \in T \tag{7}$$

The fuel cost for each capacity block of a unit $FC_{u,z,b,t}$, considers the shares of the different fuel type used in a unit $FS_{u,z,f,t}$, their fuel costs and the lower heating rate for each capacity block for each fuel type $HR_{u,z,b,f,t}$. This is depicted in Eqs. (8) and (9).

$$FC_{u,z,b,t} = \sum_{f \in F} FC_{u,z,b,f,t} * HR_{u,z,b,f,t} * FS_{u,z,f,t} \qquad \forall u \in U^{hth}, \quad f \in F, \quad z \in Z, \quad b \in B, \quad t \in T \tag{8}$$

$$\sum_{f \in F} FS_{u,z,f,t} = 1 \qquad \forall u \in U^{hth}, \quad z \in Z, \quad f \in F, \quad t \in T \tag{9}$$

The priced energy offer $PEO_{u,z,b,t}$ of the hydrothermal unit is accepted if its higher or equal than its minimum variable cost $VC^{min}_{u,z,t}$, as shown in Eqs. (10) and (11)

$$PEO_{u,z,b,t} \geqslant VC^{min}_{u,z,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad b \in B, \quad t \in T \tag{10}$$

$$\frac{\sum_{b \in B} PCB_{u,z,b,t} * PEO_{u,z,b,t}}{P^{max}_{u,z,t}} \geqslant VC^{min}_{u,z,t} \qquad \forall u \in U^{hth}, \quad z \in Z, \quad b \in B, \quad t \in T \tag{11}$$

Moreover, the energy offer can't exceed an upper value CAP_t, set by the regulatory authority of energy, as shown in Eq. (12).

$$PEO_{u,z,b,t} \leqslant CAP_t \qquad \forall u \in U^{hth}, \quad z \in Z, \quad b \in B, \quad t \in T \tag{12}$$

3.2.3. Imports, exports and pumped storage constraints

The power flows of imports and exports, the net power injections from both units and the interconnected power systems, the power withdrawal of pumped storage units $e \in E$ and the constraints of each interconnected system $n \in N$ for imports, and exports, as well for pumped storage units $e \in E$ are defined in Eqs. (20)–(30) of a recent work [31].

3.2.4. System's energy requirements and energy balance

The system's requirements for all energy reserve types, i.e., primary-up, secondary-up and down, tertiary, as well as fast secondary-up and down respectively in each time period $t \in T$, as well the energy balance of the overall power system are defined in Eqs. (42)–(47) and (55) respectively of a recent work [31]. The reserve constraints for each hydrothermal unit, as well as the ramp-rate and the corridor limit constraints are defined in Eqs. (31)–(41) and (48)–(54) respectively of a recent work [31].

The overall problem is formulated as an MILP (mixed-integer linear programming) problem, involving the cost minimization objective function (1) subject to above mentioned constraints.

3.3. Demand response & retailers' profitability

Demand response is incorporated in the UCP model, based on a methodology developed at a previous work [27] that estimated the short-run price elasticity of residential electric demand. Electricity demand ($CONEL_t$), is correlated to Gross domestic product (GDP_t), to Employment ($EMPL_t$), the heating and cooling degree days (HDD_t and CDD_t respectively), the Low voltage residential electricity tariff ($PRICE_t$) from the dominant retailer, namely Public Power Corporation (PPC) and to the price of light fuel (LFOIL) for the residential sector, where both prices are deflated by the Consumer Price Index. Using an error correction model (ECM), short- and long-run effects can be captured by estimating the short- and long-run elasticities, respectively.

The short-run equations for the electricity consumption:

$$\begin{aligned}\Delta CONEL_{s,t} &= a_0 + a_1\Delta CONEL_{s,t-1} + \sum_{i=1}^{j} b_1 \Delta GDP_{t-i} \\ &\quad + + \sum_{i=0}^{k} b_2 \overset{-}{PRICE}_{t-i} + \sum_{i=0}^{l} b_3 \overset{+/-}{LFOIL}_{t-i} \\ &\quad + \sum_{i=0}^{m} b_4 \overset{+}{EMPL}_{t-i} + \sum_{i=0}^{n} b_5 HDD_{t-i} + + \sum_{i=1}^{o} b_6 CDD_{t-i} \\ &\quad + + \gamma u_{t-1} - + \delta e_t \end{aligned} \tag{13}$$

where Δ is the first difference operator, γ is the coefficient of the error correction term, u_{t-1} is the lagged disturbance term of the long-run equation and the lag orders j, k, l, m, n, o are chosen so as to make e_t white noise. The crucial parameter for the demand response is the price elasticity.

Aiming at incorporating demand response in the wholesale market, we assume, that final consumers have a tariff linked to SMP plus a margin for the retailer, as given from the following equation. Practically this means that the final consumers have telemetering and control systems to adjust their load demand to changes in the wholesale market.

$$TARIFF_{s,r,c,t} = SMP_{s,t} + MARGIN_{s,r,c,t} \tag{14}$$

for each retailer $r \in R$ and customer type $c \in C$.

Which would lead to the following revenues for the retailers:

$$REVENUE_{s,r,t} = \sum_{c \in C} MARGIN_{s,r,c,t} * D_{s,r,c,t} \tag{15}$$

However, we consider that final consumers respond to wholesale price fluctuations, when a tolerance ($TOL_{s,c,t}$) in the difference between the retailer tariff ($TARIFF_{s,r,c,t}$) and the wholesale price ($SMP_{s,t}$) is activated, as shown in the following equation:

$$\begin{aligned} D'_{s,t} &= D_{s,t} - b_2 * \sum_{r \in R} \sum_{c \in C} \frac{TARIFF_{s,r,c,t} - SMP_{s,t}}{SMP_{s,t}} * D_{s,r,c,t}, \\ & if \frac{|TARIFF_{s,r,c,t} - SMP_{s,t}|}{SMP_{s,t}} \geqslant TOL_{s,c,t} \end{aligned} \tag{16}$$

This leads to a Demand Response $DR_{s,t}$ of the aggregate demand in the wholesale electricity market:

$$DR_{s,t} = D'_{s,t} - D_{s,t} \tag{17}$$

The updated demand $D'_{s,t}$ leads to an Imbalance Marginal Price ($IMP_{s,t}$), which is different for the SMP, as long as there is a Demand Response.

Therefore, the retailers' revenue is now estimated form the following equation:

$$\begin{aligned} REVENUE'_{s,r,t} &= \sum_{c \in C} TARIFF_{s,r,c,t} * D_{s,r,c,t} - \sum_{c \in C} SMP_{s,t} * D_{s,r,c,t} \\ &\quad - \sum_{c \in C} DR_{s,r,c,t} * IMP_{s,t} \\ REVENUE'_{s,r,t} &= \sum_{c \in C} MARGIN_{s,r,c,t} * D_{s,r,c,t} - \sum_{c \in C} DR_{s,r,c,t} * IMP_{s,t} \end{aligned} \tag{18}$$

Which leads to the following two scenarios:

$$\text{(a)}\ REVENUE'_{s,r,t} = \sum_{c \in C} MARGIN_{s,r,c,t} * D_{s,r,c,t}, \tag{19}$$

$$if\ \frac{|TARIFF_{s,r,c,t} - SMP_{s,t}|}{SMP_{s,t}} < TOL_{s,c,t}$$

$$\begin{aligned} \text{(b)}\ REVENUE'_{s,r,t} &= \sum_{c \in C} MARGIN_{s,r,c,t} * D_{s,r,c,t} \\ &\quad - \left(D_{s,t} - b_2 * \sum_{r \in R} \sum_{c \in C} \frac{TARIFF_{s,r,c,t} - SMP_{s,t}}{SMP_{s,t}} * D_{s,r,c,t} - D_{s,t} \right) * IMP_{s,t} \\ REVENUE'_{s,r,t} &= \sum_{c \in C} MARGIN_{s,r,c,t} * D_{s,r,c,t} + b_2 \\ &\quad * \sum_{r \in R} \sum_{c \in C} \frac{TARIFF_{s,r,c,t} - SMP_{s,t}}{SMP_{s,t}} * D_{s,r,c,t} * IMP_{s,t} \end{aligned} \tag{20}$$

$$if\ \frac{|TARIFF_{s,r,c,t} - SMP_{s,t}|}{SMP_{s,t}} \geqslant TOL_{s,c,t}$$

The profitability of all retailers is:

$$REVENUE'_{s,t} = \sum_{r \in R} REVENUE_{s,r,t} \tag{21}$$

Therefore, the retailers' profitability is strongly linked to relationship among the following set of variables:

- $\frac{MARGIN_{s,r,c,t}}{SMP_{s,t}}$ and $TOL_{s,c,t}$
- $IMP_{s,t}$ and $SMP_{s,t}$

The retailers' revenues are not affected:

- for fluctuations of $\frac{MARGIN_{s,r,c,t}}{SMP_{s,t}}$ within the range of demand responsiveness, namely $-\ TOL_{s,c,t}$ up to + $TOL_{s,c,t}$.
- for specific periods, where the IMP will not deviate from SMP, because of the available energy supply offers

In rest cases, the retailers' profitability is in high risk, even for reporting losses.

4. The Greek electricity industry

The integrated model is applied in the case of the Greek interconnected system, which consists of the north and the south system. Although the electricity market operator does not implement market splitting between the two subsystems, in case there is a bottleneck in transmitting power from the north system, where several old power units are installed, to the south system, where most of the new units have been installed to meet the subsystem high power demand, the integrated model includes this capability, by considering the maximum allowable corridor flow of 3100 MW between the north and the south subsystem of the Greek interconnected power system. The interconnected power system, being dominated over the last decades by lignite units located mainly in north Greece, has been sharply transformed in a more balanced mix, concerning the installed capacity. The natural gas units' capacity, from fifteen natural-gas fired (both natural gas combined cycle and natural gas open cycle units) power plants, has a cumulative capacity of 4.81 GW and overpassed the lignite units' capacity of 4.03 GW of fifteen lignite-fired units, according to the latest monthly energy report of LAGIE of October 2016 [34]. Moreover, the system has an old and very rarely used oil-fired power plant with a total capacity of 0.29 GW and sixteen hydroelectric units whose capacity equals 3.17 GW. The renewables capacity has been increased very sharply over the last decade, with a total of 4.81 GW, constituting of 1.99 GW of wind turbines, 2.44 GW of photovoltaics, 0.1 GW of high-efficiency combined heat and power units, 0.06 GW of biomass units, and 0.22 GW of small hydroelectric units in total.

The Greek interconnected system is interconnected with the systems of five countries (Albania, Bulgaria, FYROM, Turkey, and Italy). The main operational and economic characteristics of the installed units are available in our previous contributions [31,33]. The Greek day-ahead market -for the time being- is organized as a mandatory pool. This market is organized as a two-sided power auction where load representatives (e.g. retailers, exporters) and suppliers (e.g. generators, importers) submit 24 purchasing bids/selling offers respectively, one for each hour of the following day. In order to clear the market, the market operator collects all the offers/bids and determines aggregate sale and purchase curves by sorting the sale offers according to increasing prices, and the purchase bids in the inverse order. The objective of the electricity market and transmission system operator, LAGIE and IPTO in case of Greece, refers to electricity demand and power reserves satisfaction in the most economical way.

Most of the demand in the Greek interconnected system concerns the network consumption. Fig. 2 presents the evolution of the share of network (low and medium voltage) consumers compared to system (high voltage) consumers, for each month in year 2015. Network consumer represent about 82% of the total consumption of the interconnected electric system.

Therefore, considering that about 80% of the electricity demand concerns low and medium voltage consumption and the fact that large consumers already implement some demand response measures, as they have telemetering and control systems, we consider – for simplification of the presentation of the outputs – that similar – in the philosophy and not the margin- flexible tariffs are applied to all consumers. Therefore, the price elasticity, incorporated in the model towards capturing the demand response, is considered – for the needs of this paper – to be the same among all consumers. Different elasticities for different consumers categories can be incorporated, in case such price analytical elasticities are identified. Table 1 provides the short-run elasticities that have been estimated in our previous work, concerning the residential consumers. This price elasticity is incorporated in the model, for the whole electricity demand, although it concerns the residential consumers.

5. Results and discussion

This section provides the results and a detailed discussion of various scenarios that have been considered. The problem has been solved to global optimality making use of the ILOG CPLEX 24.7.2

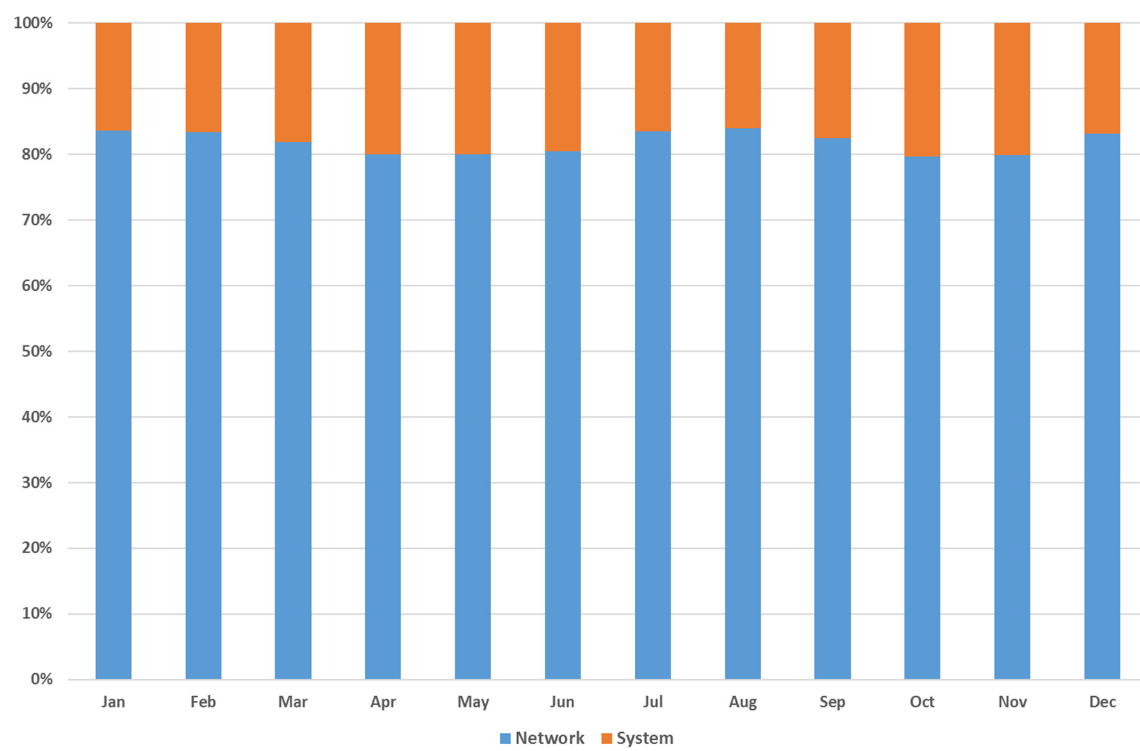

Fig. 2. Share (%) of consumption for the network and system of the Greek interconnected system, for each month in year 2015.

Table 1
Short-run elasticities of residential electricity demand.

Short-run elasticities	ΔGDP	ΔEMPL	ΔPRICE	ΔLFOIL	ΔCDD	ΔHDD	ECT
Dependent variable ΔCONEL	0.19*** (1.89)	0.61** (2.45)	−0.08** (−1.95)	−0.04 (−0.82)	−0.15* (−3.70)	0.13*** (1.71)	−0.32* (−4.66)

All the relevant estimates are corrected for heteroscedasticity and autocorrelation by using the Newey-West (1987) consistent covariance estimator.
*** Asterisks denote the significance at 10% levels, respectively. The numbers in parenthesis denote the *t*-statistic.
** Asterisks denote the significance at 5% levels, respectively. The numbers in parenthesis denote the *t*-statistic.
* Asterisks denote the significance at 1% levels, respectively. The numbers in parenthesis denote the *t*-statistic.

solver incorporated in the General Algebraic Modelling System [35] tool.

The paper aims to quantify the profitability for retailers with price responsive customers, as well as their risk. The integrated model enables the estimation of the evolution of wholesale electricity price, under different levels of demand response. The day-ahead electricity market is characterized from non-linearity in the effect of demand response. Figs. 3 and 4 present the evolution of the aggregate demand curve and the System Marginal Price (SMP) respectively over a 24hour period, for different levels of

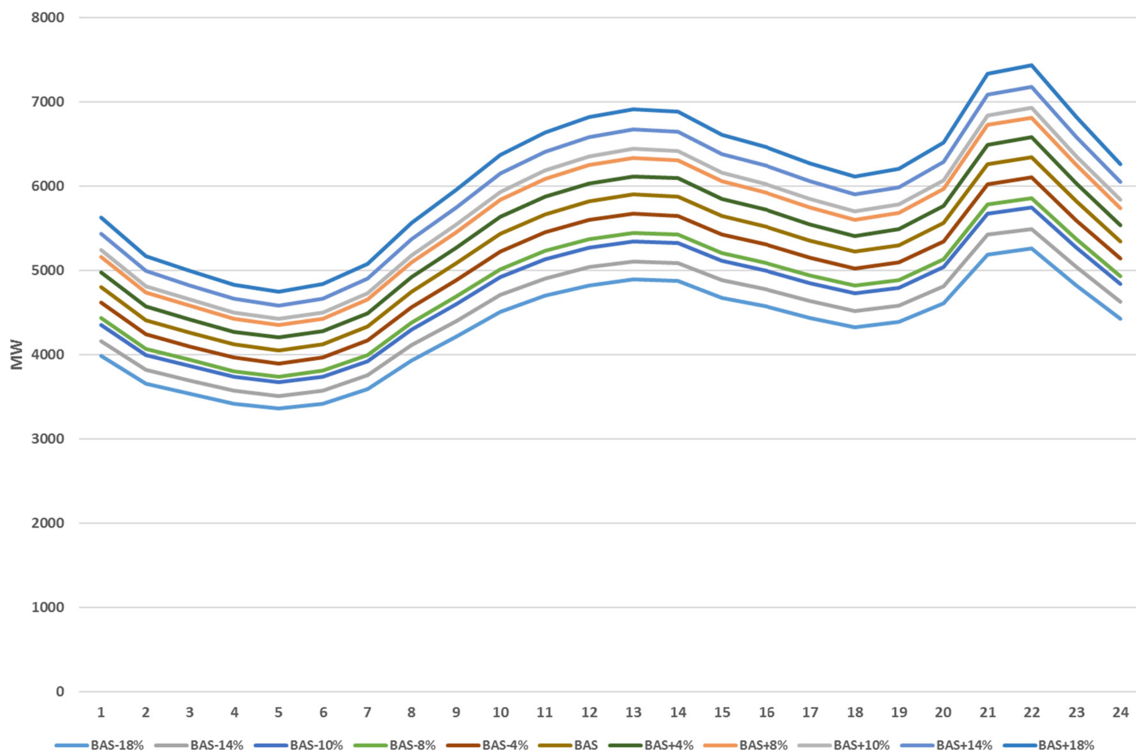

Fig. 3. Aggregated demand curve evolution over a 24hour period, for different levels of demand response (% change) compared to the baseline demand curve (BAS) (MW).

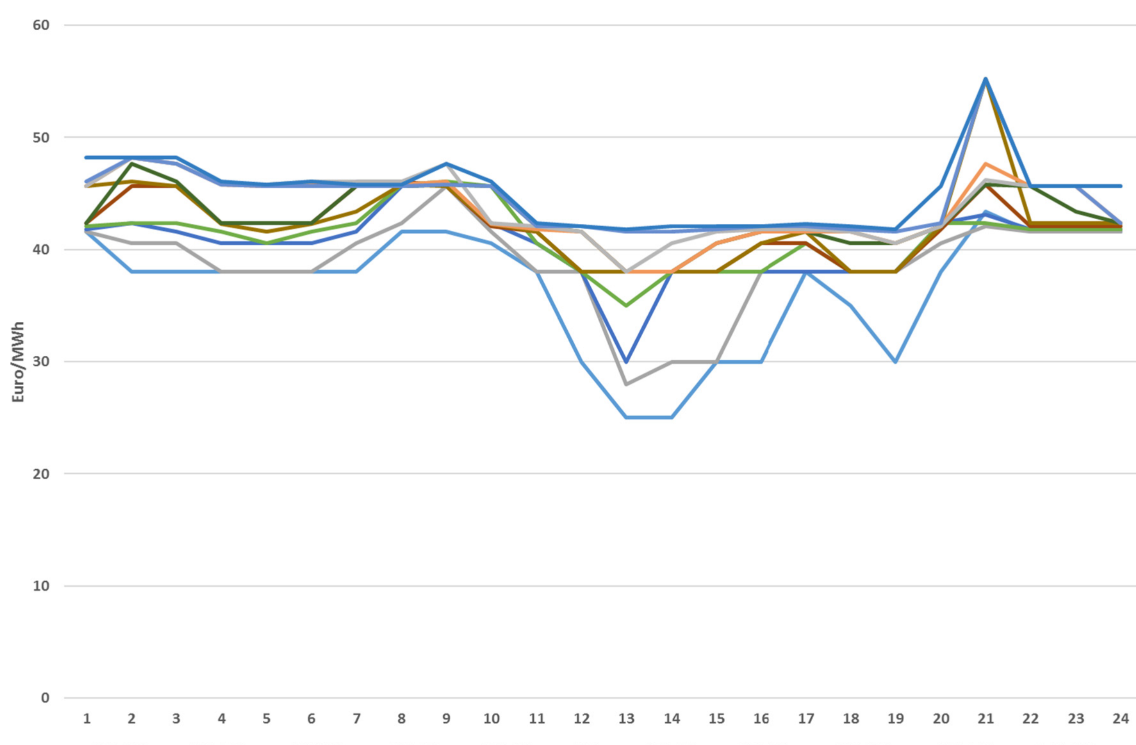

Fig. 4. System Marginal Price (SMP) evolution over a 24-h period, for different levels of demand response (% change) compared to the baseline demand curve (BAS) (Euro/MW h).

demand response (% change) compared to the baseline demand curve (BAS scenario). This depicts the fact that a linear decrease of increase of aggregate demand, due to demand response, leads to non-linear evolution the SMP, as its solution on a number of factors presented in the above formulation of the UCP problem.

The non-linear evolution of SMP is strongly linked to the marginal cost of power plants, their bidding strategies and their technical characteristics. Therefore, the power mix is also not evolving linearly to the changes of demand response. This is shown in Figs. 5 and 6, which present the evolution of natural gas and lignite units'

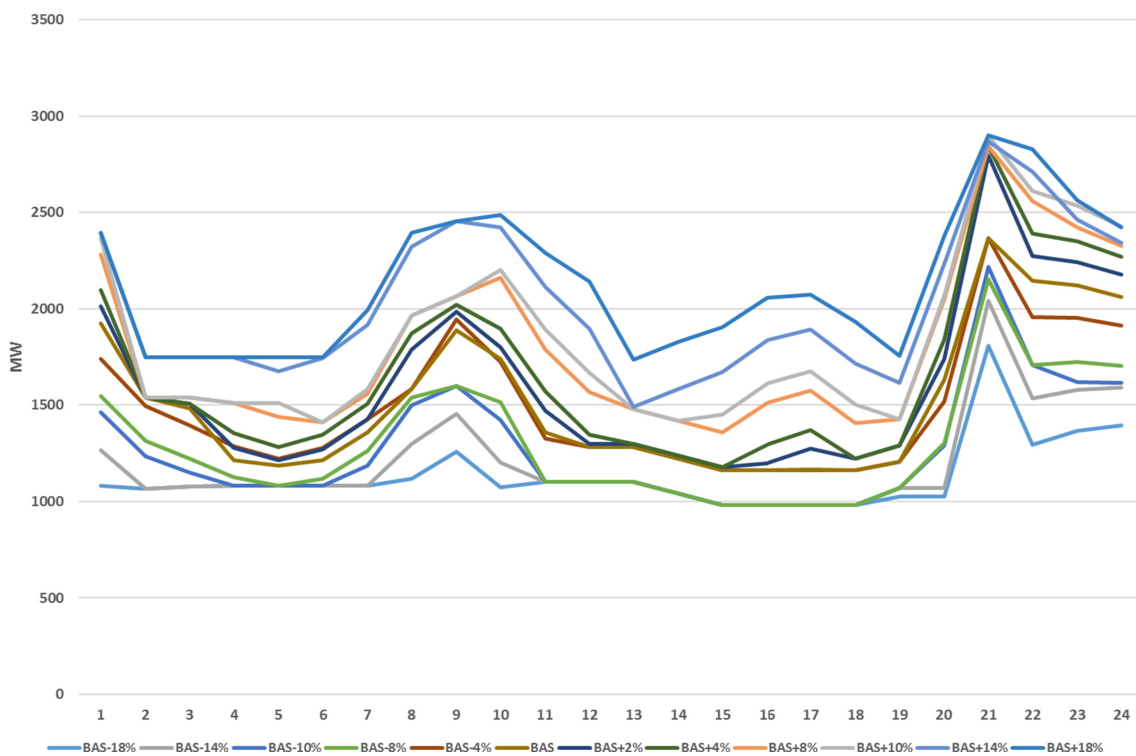

Fig. 5. Natural gas units' output evolution over a 24-h period, for different levels of demand response (% change) compared to the baseline demand curve (BAS) (MW).

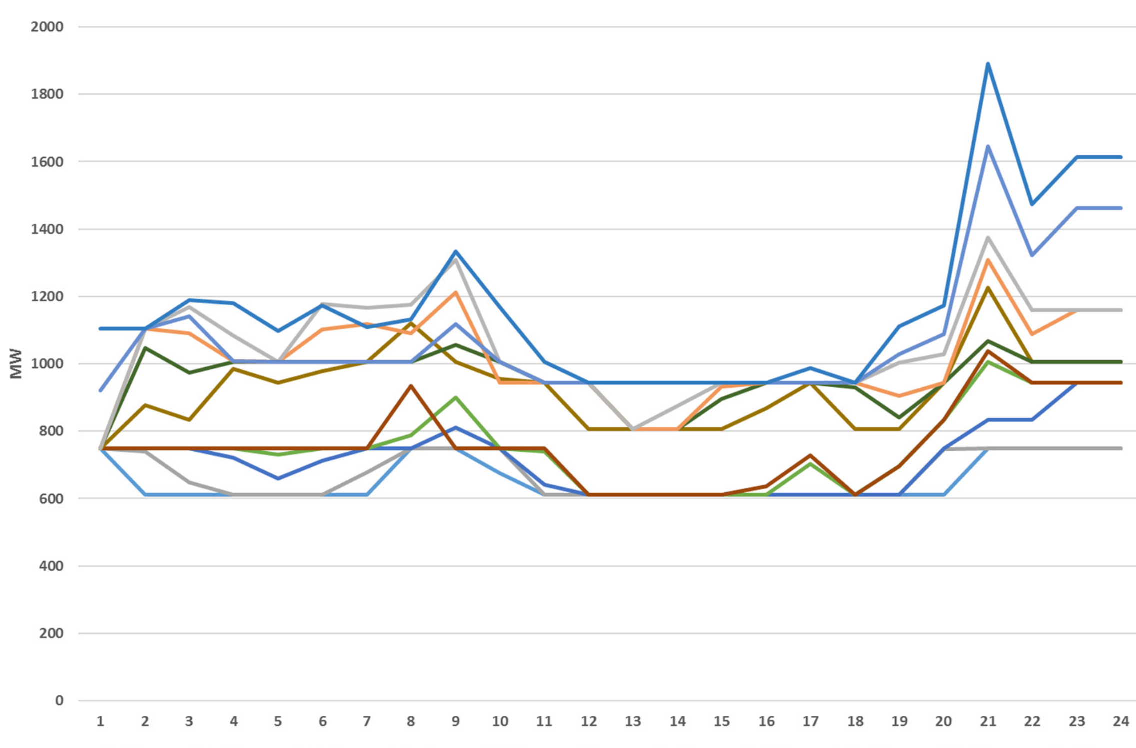

Fig. 6. Lignite units' output evolution over a 24-h period, for different levels of demand response (% change) compared to the baseline demand curve (BAS) (MW).

output respectively over a 24-h period, for different levels of demand response (% change) compared to the baseline demand curve (BAS).

In fact, the penetration of different fuel and technology types on the energy mix, is strongly related to their competitiveness, but as well as the demand level and the availability of power units, such as mandatory hydro, RES and commissioning units that participate in the day-ahead market with non-priced energy offers. The penetration capability of the different fuels is depicted in Fig. 7, which presents the average power mix (MW) per fuel type for different levels of average daily generation (MW h), while Fig. 8 presents the evolution of demand range (minimum, average, maximum) over a 24-h period, compared to those of Mandatory hydro, RES and Commissioning units.

The scenarios examined in the paper concern the cases where the retailers' customers are price responsive or not. The model is used to compare the profitability of the retailer among those two scenarios. Concerning the case with demand response, for the needs of our study we consider that all the retailers provide a tariff to their customers with a certain margin, equal to 10%. In the following figures we provide results for all retailers and for all category types, for simplicity reasons. Moreover, we do not consider the uplift accounts, which charge the retailers when buying energy from the wholesale market. Those accounts concern the supplementary costs, such as start-up and ancillary services costs for the remuneration of power units.

As mentioned above, the final consumers respond to wholesale price fluctuations, under the considerations that they exceed a tolerance level, when comparing the SMP and the tariffs provided by the retailer. Fig. 9 presents the evolution of % change between retailer's tariff (TARIFF) and system marginal price (SMP), compared to tolerance level (TOL) and the activation of demand response in case of exceeding tolerance levels (TOL_exc) over a 24-h period. This means that the consumers respond to the majority of the 24-h period. It has to be mentioned, that the data used in the model, represent a typical real day of spring 2016 of the Greek interconnected power system.

The activation of the demand response for the consumers, based on the price elasticity b2 and the tolerance levels, lead to a new aggregate energy demand, which is cleared by the TSO through an imbalance marginal price, estimated again with UCP model. Fig. 10 presents the evolution of aggregate demand (DEMAND) that participated in the day-ahead market compared to the aggregate demand (DEMAND') cleared in the imbalance market, as it was adjusted based on the Demand Response of the final consumers, over a 24-h period.

The new aggregate energy demand leads to a different marginal price, represented by the imbalance marginal price. Fig. 11 presents the evolution of retailer's tariff (TARIFF) compared to the system marginal price (SMP) and the imbalance marginal price (IMP) over a 24-h period. It is obvious again the non-linearity in the changes of IMP compared to SMP, for different levels of demand response. Fig. 12 presents the evolution of differences between retailer' tariff minus system marginal price (TARIFF-SMP) and tariff minus imbalance marginal price (TARIFF-IMP) over a 24-h period.

The new marginal price and the new aggregate energy demand affect the profitability of the retailers. Fig. 13 presents the evolution of retailers' profitability (REVENUE) with non-responsive customers with that (REVENUE') when consumers respond to fluctuations of the wholesale market, above a tolerance level, over a 24-h period.

To summarize, the final profitability of the retailers is increased by 2.14%, while IMP is increased by 0.77% compared to SMP and the final demand that was cleared in the imbalance market is increased by 2.09%, compared to the aggregate demand that participated in the day-ahead market. However, at an hourly level, the above mentioned figures show higher fluctuations, leading even to losses for the retailers for some hours. The analysis undertaken

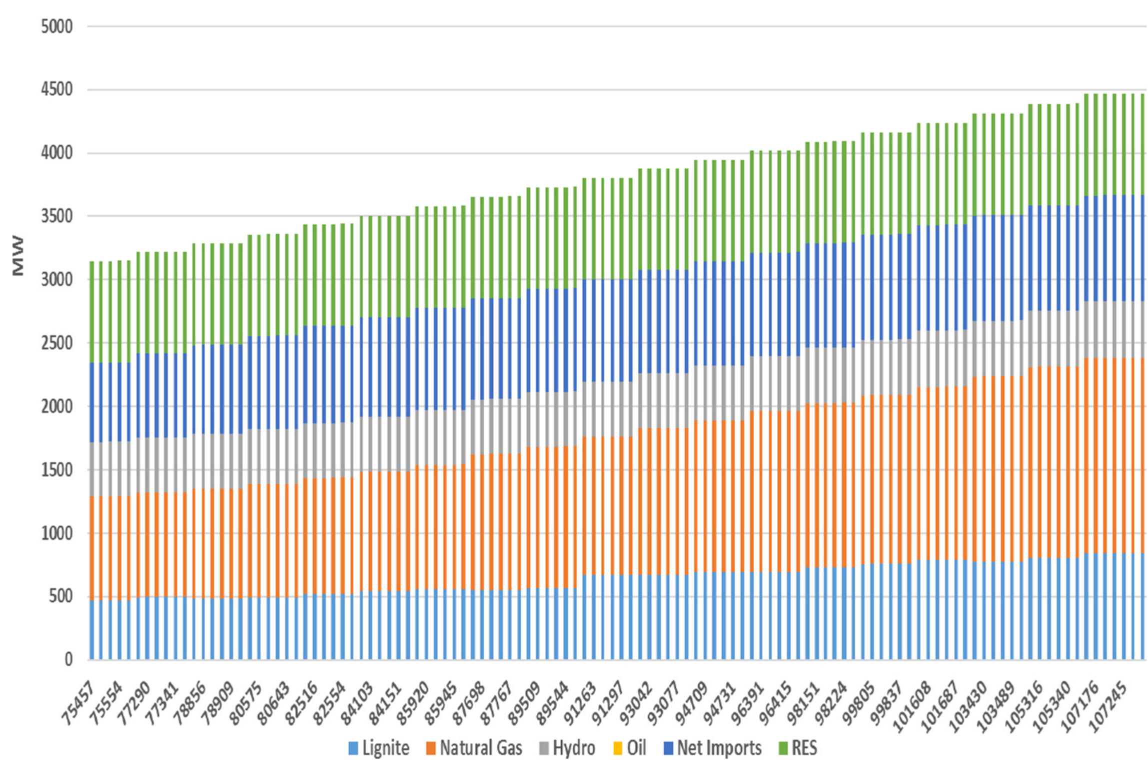

Fig. 7. Average power mix (MW) per fuel type for different levels of average daily generation (MW h).

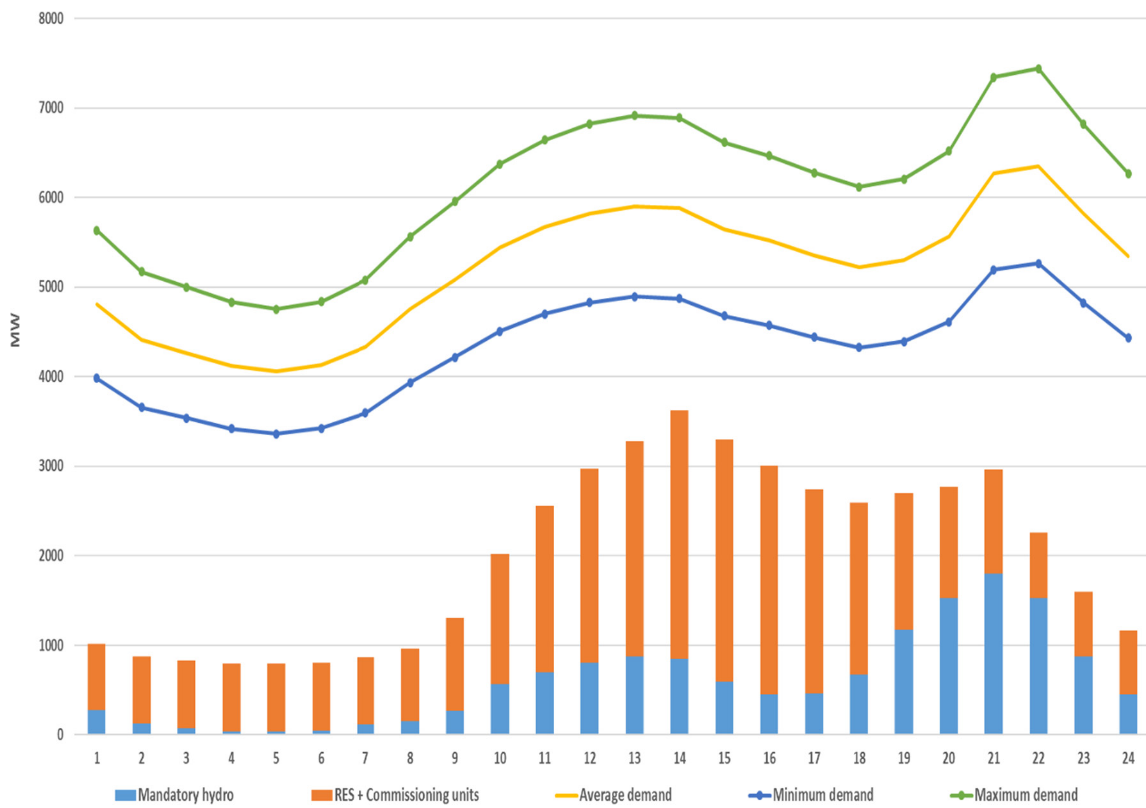

Fig. 8. Evolution of demand range (minimum, average, maximum) over a 24-h period, compared to those of Mandatory hydro, RES and Commissioning units (MW).

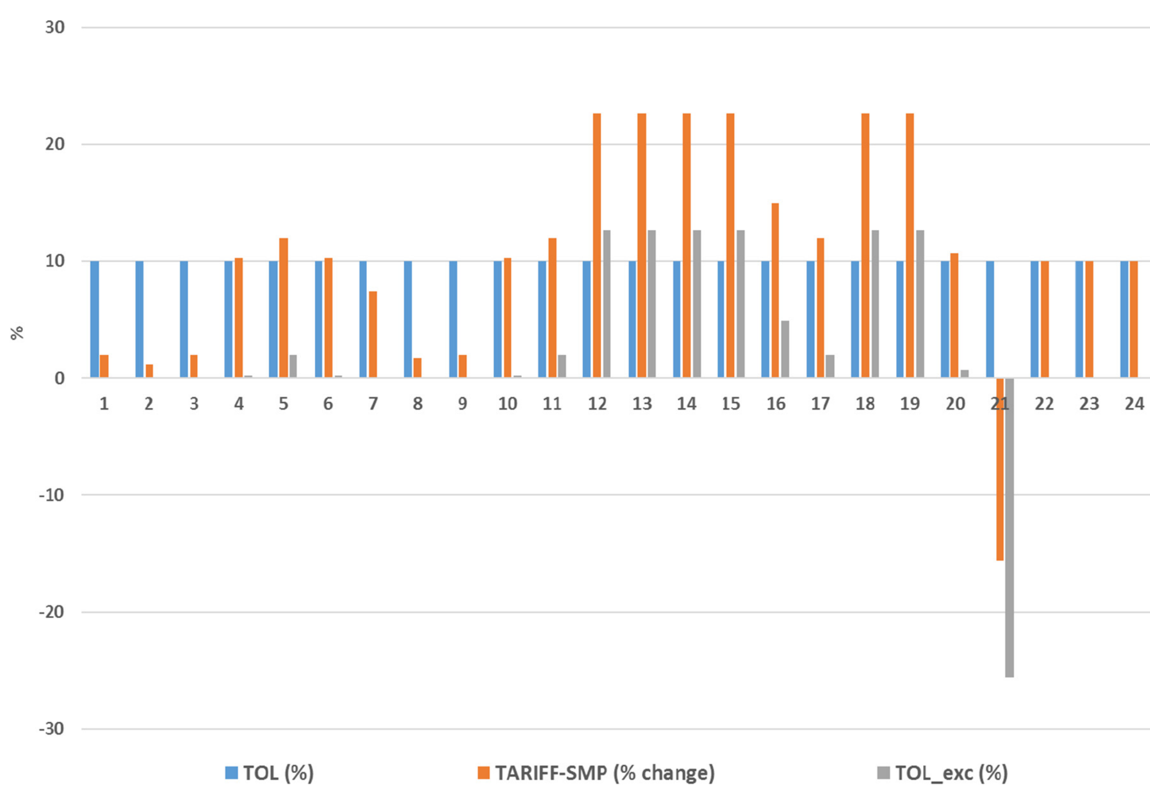

Fig. 9. Evolution of % change between retailer's tariff (TARIFF) and system marginal price (SMP), compared to tolerance level (TOL) and the activation of demand response in case of exceeding tolerance levels (TOL_exc) over a 24-h period.

provides useful insights on the risk the retailers face from participating in the wholesale and retail markets, having price responsive customers.

An important aspect of the integrated model is its capability to assess the uncertainty of several crucial techno-economic parameters that affect the electricity price, such as temperature, demand,

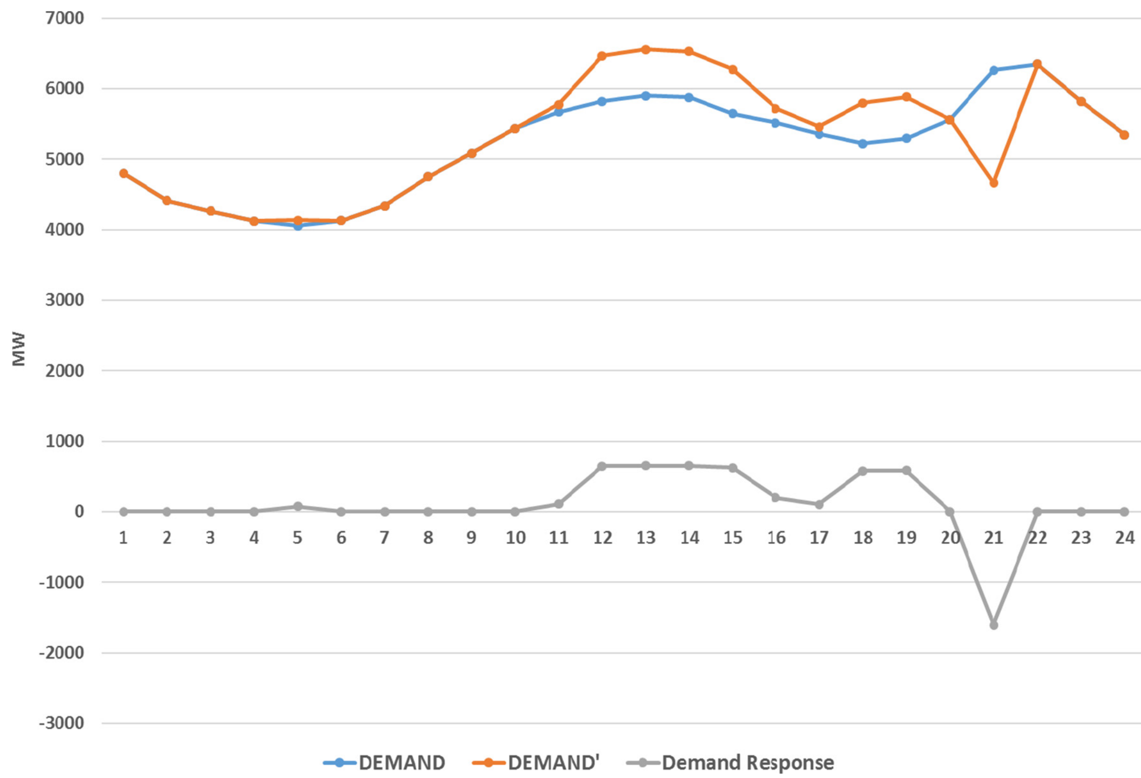

Fig. 10. Evolution of aggregate demand (DEMAND) participated in the day-ahead market and the aggregate demand (DEMAND') cleared in the imbalance market, considering the demand flexibility of the consumers (Demand Response) over a 24-h period.

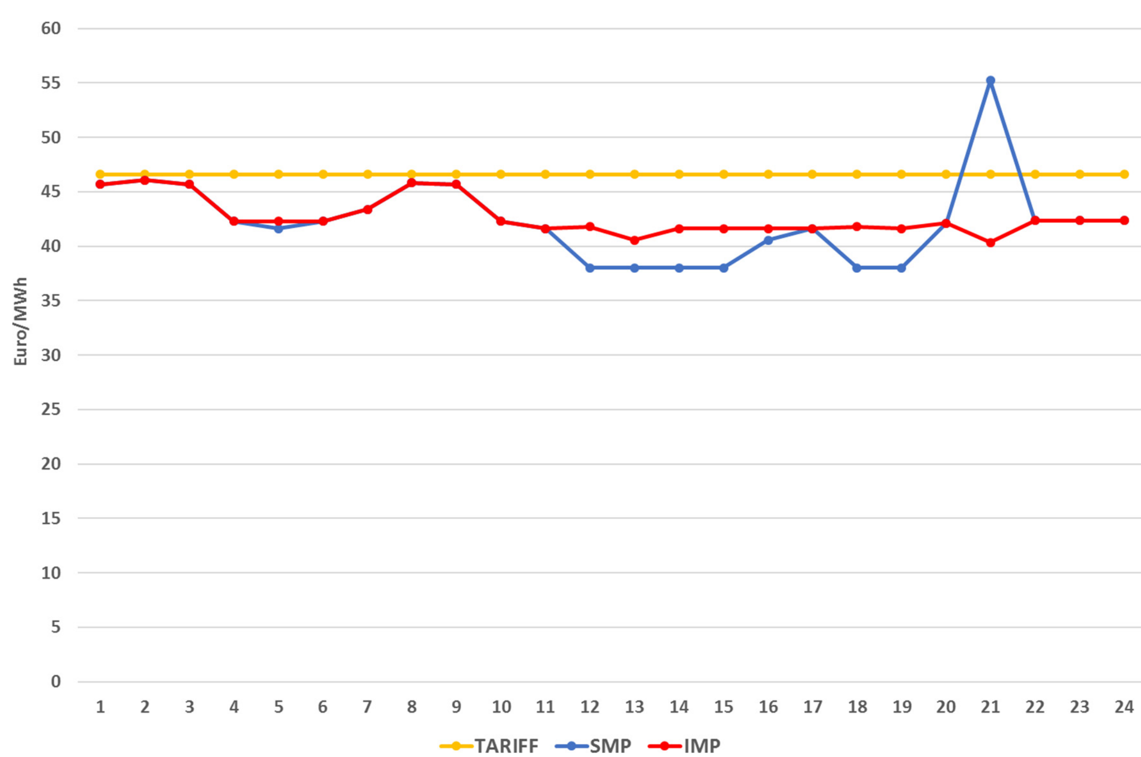

Fig. 11. Evolution of retailer' tariff (TARIFF) compared to the system marginal price (SMP) and the imbalance marginal price (IMP over a 24-h period.

fuel and CO2 prices, merit order of generation plants, renewables and hydropower capacity, market participants' strategies, network congestion and others. The integrated model, by implementing a Monte Carlo analysis on the above factors, it can present a range of revenue for the retailers. Considering, that the most crucial one for their profitability is the demand evolution, we have

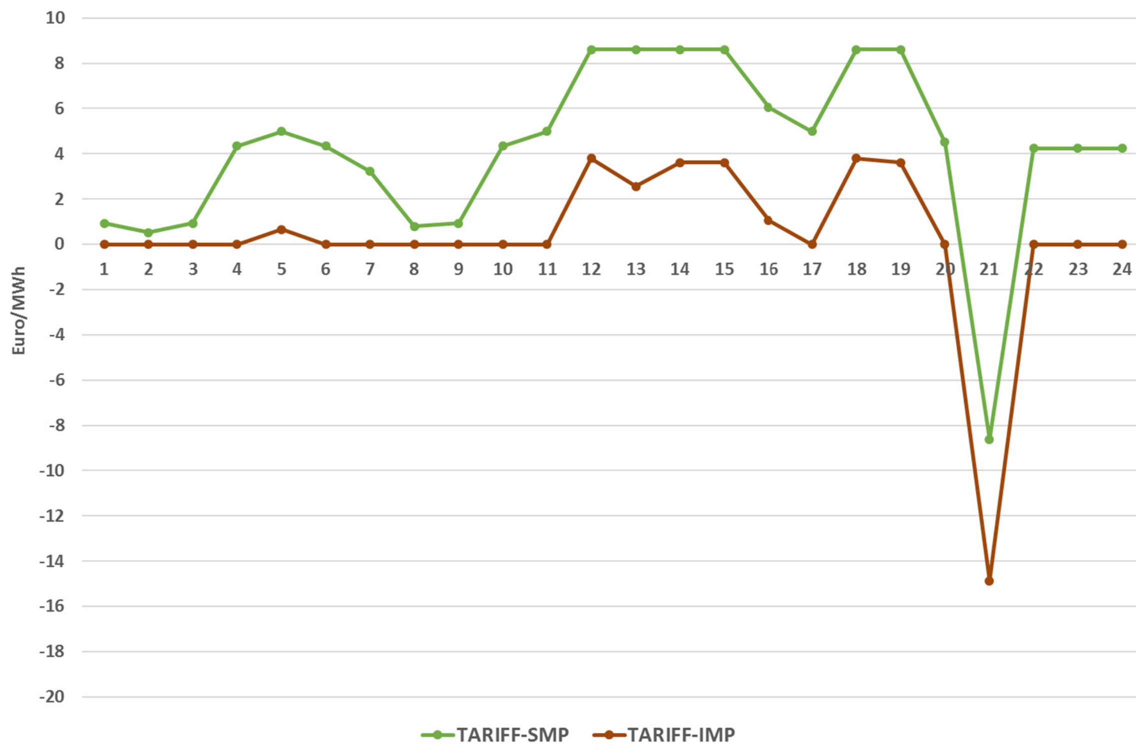

Fig. 12. Evolution of differences between retailer' tariff minus system marginal price (TARIFF- SMP) and tariff minus imbalance marginal price ((TARIFF-IMP) over a 24-h period.

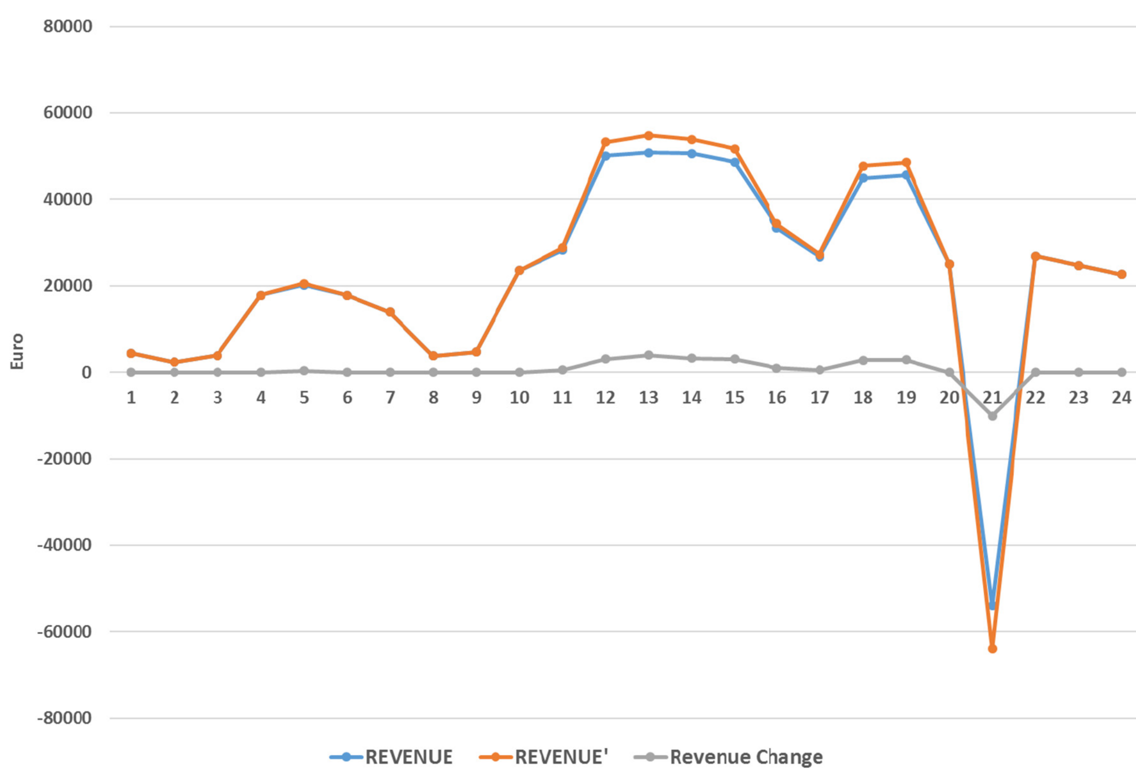

Fig. 13. Evolution of retailers' profitability (REVENUE) with non-responsive customers with that (REVENUE') when consumers respond to fluctuations of the wholesale market, above a tolerance level, over a 24-h period.

implemented a Monte Carlo analysis, assuming a ± 20% deviation over its reference prices. Fig. 14 presents the distribution of retailers' profitability change, between the case of non-responsive customers and the case when consumers respond to fluctuations of the wholesale market, above a tolerance level. It can be derived that the retailers have increased revenues by 2.43% on average,

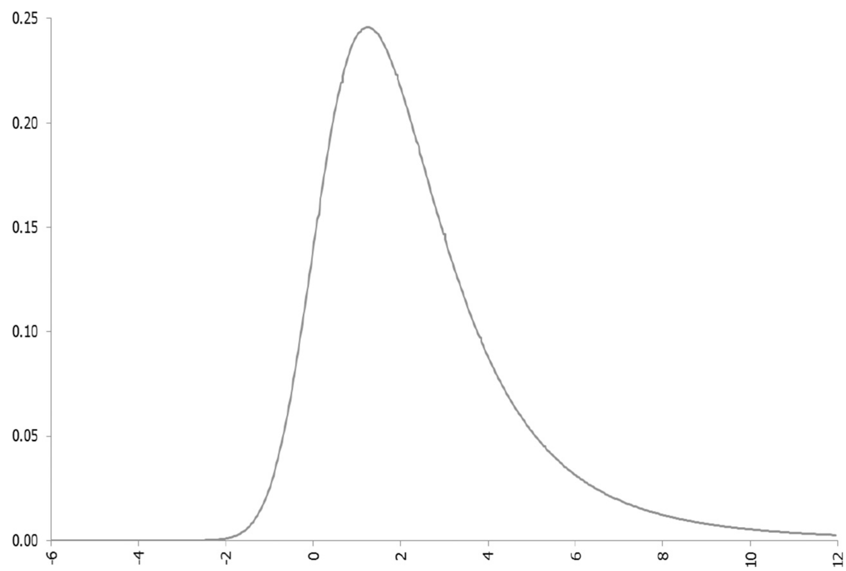

Fig. 14. Distribution of retailers' profitability change, between the case of non-responsive customers and the case when consumers respond to fluctuations of the wholesale market, above a tolerance level.

which derived mainly form the fact that the consumers are price responsive above a tolerance level. However, there are about 10% of the cases that retailers would have losses. This figure would be even higher, in case of omitting of the tolerance level. In such case, the distribution curve would be more close to 0% revenue change and more symmetrical to this figure.

The integrated model is useful for decision makers concerning the structure of the electricity markets and the expansion of the power system. But it is mainly useful for retailers operating in real electricity markets, as it provides price signals on their profitability and risk. The integrated model can provide insights to the retailers on the formation of the tariffs for their final consumers, towards eliminating their risk and maximizing their revenues. This could be implemented, by increasing the tariff charges for their consumers for the time periods where there is small probability for price fluctuation of the wholesale market. On the other hand, for the time periods with increased probability for wholesale price fluctuations, the retailer could fix its tariff price or even decrease the price, in case the retailer does not aim at affecting the average price for its final consumers.

To sum up, the presented modelling methodology is generic, as it could be applied with different modelling approaches and to different case studies. The retailers in electricity markets are facing the same problem, namely inheriting the risk of the behaviour of their consumers. Therefore, the conclusions deriving from this case study are applicable for international electricity markets, as the adoption of risk provisions and the setting of tariffs based on the sensitivity of wholesale price fluctuations would eliminate their risk and increase their profitability.

6. Concluding remarks

The evolution of smart networks is expected to be radical over the next years. The final retail consumers will start responding to the price signals from the wholesale electricity markets. Therefore, this demand flexibility will lead to load curve reshaping, eliminating the needs for new infrastructure, as the efficiency, reliability and economics of the power systems can be improved. However, there is a trade-off between demand response deployment and economic benefits for an electricity retailer. Therefore, the demand aggregators who act as demand representatives in the wholesale market of large industrial firms, residential and commercial customers are in high risk in case their customers respond to the fluctuations of real-time market prices.

In order to estimate the profitability of retailers at a demand response market environment, the authors develop an integrated model, which integrates a Unit Commitment (UC) model, which performs the simulation of the day-ahead electricity market with an econometric model, that estimates the income and price elasticities of electricity demand. This model is further extended to estimate the retailers' revenue with demand responsive consumers. The proposed model contributes to the relevant literature examining the linkage between demand response and the wholesale power market. The applicability of the proposed model is illustrated in a case study of the Greek day-ahead electricity market. The key contributions (a) integration of Unit-Commitment problem with econometric models, (b) quantification of demand response' effect on the fluctuations of spot prices, based on their short-term price elasticities, (c) identification of periods with high price margins for electricity retailers, (d) provision of price signals on the profitability of electricity retailers and (e) provision of useful insights into the risk of electricity retailers with price-responsive consumers.

In the cases examined, it derives that the non-linearity between demand response and evolution of marginal price, inherits risk for retailers. This could lead even to losses for some periods, affecting strongly their viability. The model is useful for decision makers i.e. market, system and network operators, considering that it identifies the effect of demand responsiveness to the fluctuations of spot prices. Considering that the reduction of wholesale electricity prices reduces the market share of power plants with high marginal cost, which usually concerns units with high environmental cost, the model is useful in providing insights on the effects of energy and environmental policies. The model is mainly useful for retailers, as it provides price signals on the profitability of retailers/demand aggregators, when forming their tariffs. Therefore, the paper demonstrates that the model can provide useful insights into the risk of retailers from their price responsive customers.

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