Impact of Emissions Cost on the Mid-Term Generation Scheduling in the Greek Electricity Market

Panagiotis Andrianesis, George Liberopoulos, and Pandelis Biskas

Abstract-- The EU Emissions Trading Scheme, Europe’s main mechanism for implementing EU climate policy, is driving thermal electricity generation units to incorporate their emissions cost into their variable costs. In this paper, we investigate the impact of this incorporation on the mid-term (yearly) performance of the Greek Electricity Market. To carry out our investigation, we iteratively solve the day-ahead market problem for 365 days, assuming that the generation units internalize the emissions cost in their bids. In order to provide a realistic estimate for the market performance, we use a set of input data that is based on a projection of the current data onto the year 2013. We examine three different scenarios for the prices of gas and oil, which are used to fuel some of the thermal generation units, and seven scenarios for the CO2 prices. To enhance the confidence in our results, we perform a sensitivity analysis of the market performance with respect to outages. We conclude by discussing the major insights and potential extensions of this work.

Index Terms-- Electricity market, EU Emissions Trading Scheme.

I. NOMENCLATURE

A. Sets – Subsets - Indices

$U$ Generation units, indexed by $u$

$U_{AGC}$ Generation units that can operate in AGC mode

$(U_{AGC} \subset U)$

$h$ Hour (time period), $h = 0,1,\ldots, 24$

B. Parameters

$AGC^{max}_u$ Technical maximum of unit $u$ under AGC

$AGC^{min}_u$ Technical minimum of unit $u$ under AGC

$Exp^h_u$ Exports in hour $h$

$G^{mad}_u,h$ Mandatory output of unit $u$, hour $h$

$G^{pen}_u,h$ Penalty coefficient related to the energy balance constraint

$Imp^h_u$ Imports in hour $h$

$MD^u$ Minimum downtime of unit $u$

$MU^u$ Minimum uptime of unit $u$

$P^{exp}_u,h$ Price of exports in hour $h$

$P^{g}_u,h$ Price of energy (generation) offer of unit $u$, hour $h$

$P^{imp}_h$ Price of imports in hour $h$

$P^{pr}_u,h$ Price of primary reserve offer of unit $u$, hour $h$

$P^{pump}_h$ Price of pumping in hour $h$

$P^{sr}_u,h$ Price of secondary reserve offer of unit $u$, hour $h$

$PR^{of}_pen$ Penalty coefficient related to the primary reserve requirement constraint

$PR^{req}_u$ Primary reserve requirement

$PR^{offer}_u$ Primary reserve offer of unit $u$

$Pump^h$ Pumping in hour $h$

$Q^{max}_u$ Technical maximum of unit $u$

$Q^{min}_u$ Technical minimum of unit $u$

$RES^h$ RES injections in hour $h$

$SL^h$ System load in hour $h$

$SR^{of}_pen$ Penalty coefficient related to the secondary reserve (up and down) requirements constraints

$SRD^{+}_u,h$ Secondary reserve down requirement in hour $h$

$SRU^{req}_u,h$ Secondary reserve up requirement in hour $h$

$SR^{offer}_u$ Secondary reserve range offer of unit $u$

$ST^{avail}_u,h$ Availability status of unit $u$, hour $h$

$ST^0_u$ Initial status of unit $u$ (at hour 0)

$TR^{of}_pen$ Penalty coefficient related to the tertiary reserve requirement constraint

$TR^{offer}_u$ Tertiary reserve offer of unit $u$

$TR^{req}_h$ Tertiary reserve requirement in hour $h$

$W^h_u$ Number of hours unit $u$ has been “OFF” at hour 0

$X^0_u$ Number of hours unit $u$ has been “ON” at hour 0

C. Decision variables

$AGC^{on}_u,h$ AGC condition of unit $u$ in hour $h$ -- Dependent binary variable: $1$ = In AGC mode, $0$ = Not in AGC mode

$G^{tot}_u,h$ Generation (output) of unit $u$, hour $h$, (not including the mandatory injections)

$G^{tot,corst}_u,h$ Total generation (output) of unit $u$, hour $h$

$G^{tot,of}_{sur}$ Deficit variable related to the energy balance constraint in hour $h$

$G^{tot,of}_{sur}$ Surplus variable related to the energy balance constraint in hour $h$
constraint in hour $h$

$PR_{u,h}$ Primary reserve of unit $u$, hour $h$

$PR_{u,h}^{def}$ Deficit variable related to the primary reserve requirement constraint in hour $h$

$SRD_{u,h}$ Secondary reserve down of unit $u$, hour $h$

$SRD_{u,h}^{def}$ Deficit variable related to the secondary reserve down requirement constraint in hour $h$

$SRU_{u,h}$ Secondary reserve up of unit $u$, hour $h$

$SRU_{u,h}^{def}$ Deficit variable related to the secondary reserve up requirement constraint in hour $h$

$ST_{u,h}$ Status (condition) of unit $u$, hour $h$ – Binary variable: 1 = ON(LINE), 0 = OFF(LINE)

$TR_{u,h}$ Tertiary reserve of unit $u$, hour $h$

$TR_{u,h}^{def}$ Deficit variable related to the tertiary reserve requirement constraint in hour $h$

$V_{u,h}$ Shutdown signal for unit $u$ in hour $h$ – Dependent binary variable: 1 = Shutdown, 0 = No shutdown

$W_{u,h}$ Number of hours unit $u$ has been OFF at hour $h$

since last startup – Integer variable

$X_{u,h}$ Number of hours unit $u$ has been ON at hour $h$

since last shutdown – Integer variable

II. INTRODUCTION

The transition from the traditional monopolistic structure to deregulated electricity markets led to major reforms in the electricity sector world-wide. At the EU level, Directive 96/92/EC and its subsequent Directive 2003/54/EC [1] led to fundamental changes, with new companies entering the wholesale or retail electricity markets and the creation of transmission and distribution system operators. At the same time, in order to promote a reduction in greenhouse gas emissions, Directive 2003/87/EC [2] established the EU Emissions Trading Scheme (EU ETS), a typical cap and trade system.

The EU ETS was put into force in January 2005, and consists of a number of subsequent trading periods or Phases. The first Phase covered a 3-year period (2005-2007), while the second Phase is covering a 5-year period (2008-2012). In each Phase, the installations, which in the context of this paper refer to the generation units, have to report their emissions on a yearly basis. Initially, the installations receive an amount of free allowances from each EU Member State government according to a National Allocation Plan. In addition, the installations may buy allowances, in case of shortage, and sell or bank (save), in case of surplus; however, after the end of each Phase, the old allowances become worthless.

The role of the electricity sector is crucial as it is the sector with the largest contribution in the total emissions. In 2007, the public electricity and heat production sector accounted for one third of the total CO2 emissions in the EU-27; in Greece, the respective share was 48.2% [3]. Yet, whether the implementation of the EU ETS can result in significant emissions reduction or not is a matter of controversy. For instance, in [4], it is shown that the economic impact of the CO2 emission trading is not sufficient to outweigh the economic incentives to choose for coal (the most CO2 intensive option) in capacity expansion plans. Also, the internalization of the emissions cost may alter the merit order in which generators are dispatched in the market. This may result in cycling cost increases, which may offset the emissions reduction benefits brought in by the carbon price [5]. For example, a base load unit, which would otherwise be on most of the time, will now have to be turned off more often, as it will be operating on the margin due to its increased variable cost.

The effect of the EU ETS, in its current form, on the generation scheduling outcome was investigated in [6], under the assumption that initial allowances are obtained for free. In the case of Greece, the impact of the emissions trading on the hydro-thermal mid-term scheduling problem of a real-sized power utility was studied in [7]. The optimal mid-term operation of a hydro-thermal system and subsystem, within an emissions trading scheme was addressed in [8], in the context of stochastic optimization. In the short run, the impact of the ETS on electricity pricing is investigated in [9], with an emphasis on the market structure and market power issues. In the long-run, the capacity expansion of the Greek electrical power system in the context of emission trading was addressed in [10].

The end of Phase II of the EU ETS (December 2012) is expected to trigger significant changes to the evolution of the electricity markets, due to the increased impact of the greenhouse gas emissions cost on the energy generation cost. The electricity sector will receive no free allowances [11], and, inevitably, the cost of the emissions will pass on the electricity prices.

The goal of this paper is to investigate the mid-term (yearly) impact that the incorporation of the emissions cost in the variable cost of thermal units will have on the performance of the Greek Electricity Market (GEM).

The GEM is supervised by the Regulatory Authority for Energy (RAE) and is operated by the Hellenic Transmission System Operator (HTSO). The market rules are defined by the “Grid Control and Power Exchange Code for Electricity” [12]. Significant emphasis is put on the wholesale market rules governing the scheduling of the generation units and the energy they are called to produce. The basis of the wholesale electricity market is the Day-Ahead (DA) market, a mandatory pool where all energy injections and withdrawals are transacted.

To carry out our investigation, we “simulate” the DA market for 365 days (8,760 hours). In each day, we solve the Day-Ahead Scheduling (DAS) problem, using information on the system status from the previous day, and assuming that the generation units internalize the emissions cost in their bids. In order to provide a realistic estimate for the market performance (system marginal price, unit scheduling, etc.), we use a set of input data that is based on a projection of the current data concerning generation units, Renewable Energy Sources (RES) injections, imports/exports, system load, ancillary services requirements, etc., onto the year 2013.

In the following section, we sketch the current state of the electricity sector in Greece and a projection of it in the year 2013. In Section IV, we present the DA market and the DAS model. In Section V, we list the input data used for the numerical investigation. The results are presented in section VI. Lastly, in Section VII, we discuss the major insights and
issues for further research.

III. GREECE’S ELECTRICITY SECTOR

The main fuel used in the Greek electricity sector is domestic lignite. Greece is the second lignite producer in the EU, fourth in the world, and the lignite industry has a long tradition [13]. Apart from lignite units, the production mix also includes Combined Cycle Gas Turbines (CCGTs), Open-Cycle Gas Turbines (OCGTs), and gas-fired units, oil units, large hydro plants, and (RES), mainly wind parks, small hydros, biomass, photovoltaics, and small cogeneration plants.

Table I presents the current installed capacity by unit type [14] and a projection for the year 2013.

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Current (2010)</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of units</td>
<td>Capacity (MW)</td>
<td>Number of units</td>
</tr>
<tr>
<td>Lignite</td>
<td>22</td>
<td>4,746</td>
</tr>
<tr>
<td>CCGT</td>
<td>8</td>
<td>3,153</td>
</tr>
<tr>
<td>OCGT</td>
<td>3</td>
<td>147</td>
</tr>
<tr>
<td>Gas</td>
<td>2</td>
<td>339</td>
</tr>
<tr>
<td>Oil</td>
<td>4</td>
<td>698</td>
</tr>
<tr>
<td><strong>Total Thermal Capacity:</strong></td>
<td>9,083</td>
<td>10,083</td>
</tr>
<tr>
<td>Hydro</td>
<td>15</td>
<td>3,018</td>
</tr>
<tr>
<td><strong>Total Thermal-Hydro Capacity:</strong></td>
<td>12,165</td>
<td>13,101</td>
</tr>
<tr>
<td>RES</td>
<td>1,172</td>
<td>2,400</td>
</tr>
<tr>
<td><strong>Total Capacity (RES included):</strong></td>
<td>13,337</td>
<td>15,501</td>
</tr>
</tbody>
</table>

The total installed capacity is approximately 13,300 MW (including about 1,200 MW RES). The thermal units’ installed capacity amounts to about 9,100 MW, whereas for the hydro units it is approximately 3,000 MW. The Public Power Corporation (PPC) is the dominant company in the Greek power sector; only 5 thermal units with a total installed capacity of approximately 1,700 MW belong to private producers.

By 2013, the installed capacity is expected to reach about 15,500 MW. In particular, the scenario that we use for the purposes of this paper assumes that the RES capacity will be doubled (2,400 MW), 4 lignite units of the PPC will stop operating, and 3 new privately-owned CCGTs of about 1,250 MW will have entered the market.

In 2009, the system hourly minimum and maximum loads were 3,238 MWh and 9,761 MWh, respectively. It is expected that the load in 2013 will be at the levels of 2009. The yearly load in 2009 was reduced by 5.82% compared to the respective period in 2009. The reduction for the first 4 months of 2010 compared to the respective period in 2009 is 1.76%.

The energy generation mix (including the net imports) by fuel type for the year 2009 is presented in Fig. 1.

A new interconnection (overhead AC line) with Turkey is activated on September 2010, with which the whole country of Turkey will join the UCTE network.

![Energy generation mix by fuel type (2009). Source [14]](image)

In 2009, the share of net imports was 8.27% (Fig. 1). The analysis of the imports/exports in a yearly basis is presented in Table II.

<table>
<thead>
<tr>
<th>Interconnection</th>
<th>Imports TWh (MWh/hour)</th>
<th>Exports TWh (MWh/hour)</th>
<th>Net Imports TWh (MWh/hour)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>0.061 (7)</td>
<td>1.035 (118)</td>
<td>-0.974 (-111)</td>
</tr>
<tr>
<td>FYROM</td>
<td>3.810 (435)</td>
<td>0.006 (1)</td>
<td>3.804 (434)</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>3.418 (390)</td>
<td>-</td>
<td>3.418 (390)</td>
</tr>
<tr>
<td>Italy</td>
<td>0.311 (35)</td>
<td>2.192 (250)</td>
<td>-1.881 (-215)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>7.600 (867)</td>
<td>3.233 (369)</td>
<td>4.367 (498)</td>
</tr>
</tbody>
</table>

The figures in TWh refer to the yearly imports and exports; the figures in parentheses represent the average hourly imports and exports in MWh/hour and are calculated as the ratio of the total yearly over 8,760 hours.

IV. THE DA MARKET

The DA market operation is based on the DAS problem, which is solved daily, simultaneously for all 24 hours of the next day. The objective is to minimize the cost of matching the energy to be absorbed with the energy to be injected in the system, while meeting the reserve requirements and the generation units’ technical constraints. The DAS solution defines how each unit should operate in each hour, and determines the clearing prices of the energy and reserves.

In our model, we consider all available generation units, namely, thermal and hydro plants, imports, injections from the RES, mandatory injections from the hydro plants, exports, and pumping stations. Reserves include primary reserve, secondary up and down, and tertiary reserve (including spinning and non-spinning). The system load and the reserve requirements are exogenously determined by the HTSO, and, for the purposes of this paper, are considered as parameters of the optimization problem. The transmission constraints, which in the case of Greece’s electricity market, amount to a North-to-South transmission corridor constraint, are not included in the model; it is expected that, for the load levels which are used in the numerical investigation, the transmission constraint will hardly ever be
The producers submit energy offers for each hour of the following day as a stepwise function of price-quantity pairs, with successive prices being strictly non-decreasing. For simplicity, we assume a single price bid for energy. The producers also submit reserve bids as price-quantity pairs, and shutdown costs. The technical characteristics of the generation units that constitute the constraints of the DAS problem include the technical minimum and maximum output, the AGC minimum and maximum, the maximum reserve availability, and the minimum uptimes and downtimes. Ramp up/down limits are not considered in our analysis as they are rarely binding, and their impact on the yearly results is negligible.

The DAS problem can be formulated as a Mixed Integer Programming (MIP) problem. In the following, and unless otherwise mentioned, \( u \) refers to the general set \( U \).

**Objective Function:**

\[
\min \{ \text{Commitment Cost} + \text{Reserves Cost} + \text{Load Revenues} - \text{Penalty Cost} \} \quad (1)
\]

\[
\text{Commitment Cost} = \sum_{u,h} P_{h}^{mp} \cdot G_{h}^{u} + \sum_{h} P_{h}^{mp} \cdot \text{Imp}_{h} \quad (2)
\]

\[
\text{Reserves Cost} = \sum_{u,h} \left[ P_{h}^{mp} \cdot \text{PR}_{h}^{u} + P_{h}^{mp} \cdot \left( \text{SRU}_{h}^{u} + \text{SRD}_{h}^{u} \right) \right] \quad (3)
\]

\[
\text{Commitment Cost} = \sum_{u,h} Y_{h} \cdot \text{SC}_{h} \quad (4)
\]

\[
\text{Load Revenues} = \sum_{h} P_{h}^{mp} \cdot \text{Exp}_{h} + \sum_{h} P_{h}^{mp} \cdot \text{Pump}_{h} \quad (5)
\]

\[
\text{Penalty Cost} = \sum_{h} \left( G_{h}^{u} \left( G_{h}^{\text{min}} + G_{h}^{\text{max}} \right) + \text{PR}_{h}^{\text{def}} \cdot \text{PR}_{h}^{\text{def}} + \text{SRU}_{h}^{\text{def}} \cdot \text{SRD}_{h}^{\text{def}} + \text{TR}_{h}^{\text{def}} \cdot \text{TR}_{h}^{\text{def}} \right) \quad (6)
\]

**Constraints:**

\[
\sum_{u} \text{SL}_{u} + \text{Exp}_{h} + \text{RES}_{h} + G_{h}^{\text{def}} - G_{h}^{\text{min,mw}} = \quad \forall h \quad (7)
\]

\[
\sum_{u,h} \text{PR}_{h}^{u} + \text{SRU}_{h}^{u} + \text{SRD}_{h}^{u} = \quad \forall h \quad (8)
\]

\[
\sum_{u,h} \text{SRD}_{h}^{u} + \text{SRU}_{h}^{u} \geq \text{SRU}_{h}^{\text{req}} \quad \forall h \quad (9)
\]

\[
\sum_{u,h} \text{TR}_{h}^{u} + \text{SRU}_{h}^{u} \geq \text{TR}_{h}^{\text{req}} \quad \forall h \quad (10)
\]

\[
\text{SRU}_{h}^{u} + \text{SRU}_{h}^{\text{def}} \geq \text{SRU}_{h}^{\text{req}} \quad \forall h \quad (11)
\]

\[
G_{h}^{\text{def}} - \text{SRU}_{h}^{u} \geq \text{SRU}_{h}^{\text{def}} \quad \forall u,h \quad (12)
\]

\[
G_{h}^{\text{def}} - \text{SRD}_{h}^{u} \geq \text{SRD}_{h}^{\text{def}} \quad \forall u,h \quad (13)
\]

\[
\text{PR}_{h}^{u} \leq \text{ST}_{h}^{\text{req}} \quad \forall u,h \quad (14)
\]

\[
\text{SRU}_{h}^{u} \geq \text{SRD}_{h}^{\text{def}} \quad \forall u,h \quad (15)
\]

\[
\text{TR}_{h}^{u} \leq \text{TR}_{h}^{\text{def}} \quad \forall u,h \quad (16)
\]

\[
(X_{h} - \text{MU}_{h}^{u}) \left( \text{ST}_{h}^{u} - \text{ST}_{h}^{\text{def}} \right) \geq 0 \quad \forall u,h \quad (17)
\]

\[
(W_{h} - \text{MD}_{h}^{u}) \left( \text{ST}_{h}^{u} - \text{ST}_{h}^{\text{def}} \right) \geq 0 \quad \forall u,h \quad (18)
\]

\[
\text{AGC}_{u,h} \leq \text{ST}_{u,h} \quad \forall u,h \quad (19)
\]

with \( G_{h}^{\text{def}} \), \( G_{h}^{\text{req}} \), \( \text{PR}_{h}^{u} \), \( \text{SRU}_{h}^{u} \), \( \text{SRD}_{h}^{u} \), \( \text{TR}_{h}^{u} \) \( \forall u,h \). The objective function, as defined in (1), aims at minimizing the as-bid costs for energy and reserves, plus the commitment cost, minus the load revenues, plus a penalty cost. The corresponding cost components are defined in (2)-(6).

The generation cost includes the cost for energy generation from the dispatchable thermal and hydro power plants, and imports. The reserves cost includes the cost for providing primary and secondary reserve. The commitment cost includes only the shut down cost, which is assumed to be equal to the start-up cost. This is to deter the DAS program, which concerns a rather myopic horizon (24 hours) relatively to the time and effort it takes start-up and shut-down some of the units, from reaching a solution which it easily shuts down those units. The load revenues include the declarations for imports and pumping. The penalty cost is an additional term imposed in the objective function to deal with infeasibilities in the optimization problem. More specifically, selected constraints are relaxed through the introduction of deficit ("slack") and surplus variables which are multiplied with appropriate penalty coefficients, imposing additional weights in (1). The values selection for these penalty coefficients can lead to different priorities for the constraints that are to be relaxed.

Equation (7) expresses the energy balance constraint. The energy injected from the thermal and hydro plants, the imports and the RES, must equal the system load, plus the exports, plus the pumping.

Constraints (8)-(11) ensure adequacy of the different types of reserves (primary, secondary up, secondary down, and tertiary, both spinning and non-spinning). Under the current market design, the formulation of these constraints does not take into consideration the hierarchical (nested) nature of the different types of reserve; hence, it does not allow the substitutability of lower quality reserves by higher quality ones. By higher quality reserves we mean those of quicker response that can be used for satisfying reserve requirements for slower response. This feature has been addressed in the relevant literature that was motivated by the discussion on the drawbacks of sequential ancillary services markets [15]-[19], and it is shown that it may result in price inversions; therefore this design should be reconsidered, especially if the commodity of the tertiary reserve is also introduced in the market [20].

The deficit and surplus variables introduced in the formulation serve to relax the constraints of the energy balance (6) and the reserve requirements (7)-(11). The
penalty coefficients selected should be ordered in such a way that they relax the constraints in the following order: (a) tertiary reserve requirements, (b) secondary reserve requirements, (c) primary reserve requirements, and (d) energy balance (the last to be relaxed).

Inequalities (12) and (13) refer to the units’ technical maximum and minimum constraints. They also take into consideration the provision of reserves and the condition that the provision of secondary reserve requires that the unit must be in AGC mode and will therefore generate within its AGC limits. Constraints (14)-(16) state the reserve availability of the generation units. In particular, they state that the amount of each reserve type that the unit is able to provide must not exceed its offer, which reflects the maximum amount of each reserve type that the unit can provide. Note that the primary and tertiary reserve can be provided if the unit is online, whereas the provision of secondary reserve (both up and down) requires the unit to be in AGC mode.

Constraints (17) and (18) represent the minimum uptime and downtime constraints. In case of a unit startup (shutdown), the unit must stay online (offline) for a certain number of time periods (hours). Note that constraint (17) is multiplied with the availability of each unit so that it is dropped in case an outage occurs (this feature is used when we solve iteratively the DAS problem in our simulation).

Inequality (19) states that in order for a unit to be in AGC mode, it must necessarily be online. Inequality (20) represents the availability constraint of each unit.

Equalities (21)-(24) define dependent variables and declare initial values. Equality (21) states that the total generation of a unit equals a mandatory component (e.g. the mandatory hydro injections) and a component that is scheduled in the DAS.

Constraints (25)-(27) define the initial values for certain variables, and constraint (28) sets the AGC mode variable equal to zero for the units that cannot provide secondary reserve.

Note that constraints (17), (18) and (22)-(24) are not linear. To sort out for the nonlinearities, they can be replaced with equivalent inequalities, introducing auxiliary variables wherever necessary, as it is shown in [20] and [21].

The formulation that results after the above replacements is a Mixed Integer Linear Programming (MILP) problem that can be modeled and solved with any available MILP solver. Once the MILP problem is solved, a Linear Programming (LP) problem is created by fixing the integer variables at their optimal values and dropping the constraints that involve only integer variables. In particular, constraints (17)-(20) and (22)-(28) are replaced with the following:

\[ ST_{u,h} = ST^*_{u,h} \quad \forall u, h \] \hspace{1cm} (29)

\[ AGC_{u,h} = AGC^*_{u,h} \quad \forall u, h \] \hspace{1cm} (30)

\[ V_{u,h} = V^*_{u,h} \quad \forall u, h \] \hspace{1cm} (31)

Parameters \( ST^*_{u,h} \), \( AGC^*_{u,h} \), \( V^*_{u,h} \) represent the optimal values of binary variables \( ST_{u,h} \), \( AGC_{u,h} \), \( V_{u,h} \) that are obtained after solving the MILP problem.

The LP formulation allows for the calculation of clearing prices using marginal pricing theory [22]. The energy clearing price, also called System Marginal Price (SMP), is determined as the shadow price of constraint (7). As we did not model the DAS problem in its zonal form, we can use the term SMP for both producers and suppliers (without taking into account the uplifts on the price that the suppliers are called to pay). For a zonal marginal pricing model of the GEM the reader is referred to [23].

The issues regarding the pricing of ancillary services (reserves) have been extensively analyzed in [23]-[26], and are not within the scope of the paper.

V. INPUT DATA

In this section, we present the input data that we used for solving the DAS problem on an instance representing the GEM. Due to space considerations, we shall not provide in much detail all the input data. The reader is referred to [14] for the publicly available data and to [20] for a more analytic presentation of the units’ technical and economical characteristics.

As input parameters for the hourly load, the mandatory hydro injections and the pumping profile, we used the data of the year 2009, which are available in [14]. The hourly imports and exports were considered to be equal to 600 MW and 300 MW respectively. The reduced net imports are mainly due to the Turkey interconnection, by which exports to Turkey will take place, taking into account the production capacity deficit in Turkey. The hourly RES injections were considered equal to 600 MW.

The primary and secondary down reserve requirements were set at 80 MW and 150 MW, respectively. For the secondary up reserve we used the profile of Table III. The tertiary reserve requirement was set at 5% of the system load.

<table>
<thead>
<tr>
<th>TABLE III</th>
<th>SECONDARY RESERVE UP REQUIREMENTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hour</td>
<td>1-6</td>
</tr>
<tr>
<td>SRIK contours (MW)</td>
<td>100</td>
</tr>
</tbody>
</table>

In order to remove the impact of the reserve bids on the SMP, and potential gaming that may be exercised through the reserve bids, we assumed zero-priced reserve offers.

The generation units that are assumed to be in operation in 2013 were shown in Table I. For simplicity, we did not consider each hydro unit separately; instead we considered an aggregate unit that submits an energy offer above the last thermal unit for the non mandatory injections.

The maintenance schedule and the outage rate were assumed to be the same as in the year 2009. For the needs of our analysis, we generated Bernoulli-distributed random outages for each day based on the Equivalent Demand Forced Outage Rate (EFORd) values, which provide a measure of the probability that a generation unit will not be available due to a forced outage. The time for the repair of an outage was assumed to be 2 days. For the aggregate hydro unit, we assumed a total available capacity of 2,600 MW, taking into account the average EFORd of the hydro units.

Initially, all units were considered to be online so that
they would all have a common starting point. The initial values for the time counters were assigned so that they would not affect the dispatching.

For the energy offers of the thermal units, we firstly calculated their cost-based offers as follows:

\[
\text{Total Variable Cost} = \text{Fuel Cost} + \text{Operation \\& Maintenance Cost} + \text{Emission Cost}
\]

\[
\text{Emission Cost} = \text{Emission Rate} \cdot \text{Energy} \cdot \text{CO}_2 \text{ Price}
\]

The ranges of the emission rates of the generation units are provided in Table IV.

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>Number of Units</th>
<th>Emission Rates (tonCO2/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite</td>
<td>18</td>
<td>1.04-1.96</td>
</tr>
<tr>
<td>CCGT</td>
<td>11</td>
<td>0.37-0.49</td>
</tr>
<tr>
<td>OCGT</td>
<td>4</td>
<td>0.53</td>
</tr>
<tr>
<td>Gas</td>
<td>2</td>
<td>0.6</td>
</tr>
<tr>
<td>Oil</td>
<td>4</td>
<td>0.74-0.8</td>
</tr>
</tbody>
</table>

The emission rates of the lignite units vary significantly depending on the efficiency of the power plant, the quality of the lignite and other uncertainties [27], [28].

As for the \( \text{CO}_2 \) price, we examined seven scenarios: 0, 5, 10, 15, 20, 25, and 30 € per ton \( \text{CO}_2 \).

In order to obtain realistic results, we had to assume a bidding behavior for the market participants. An assumption that all the units bid at their variable cost would result in a cost-based unit commitment that would underestimate the SMP. Therefore, we assumed that the dominant company (PPC) is bidding at the variable cost, whereas the privately-owned power plants submit bids that exceed their variable cost. This assumption is not far from the current practice, which can be easily verified by observing the daily DAS results.

We also considered three different scenarios of fuel (oil and natural gas) prices: low, moderate and high; low and high include a 10% difference in fuel prices downwards and upwards respectively. The ranges of the energy offers in (€/MWh), without taking into account the emission cost, are shown in Table V.

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Number of units</th>
<th>Capacity (MW)</th>
<th>Fuel price scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Low</td>
<td>Moderate</td>
</tr>
<tr>
<td>Lignite</td>
<td>18</td>
<td>4,338</td>
<td>22-35</td>
</tr>
<tr>
<td>N. Gas</td>
<td>4</td>
<td>1,803</td>
<td>50.1-59.1</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>659</td>
<td>75.5-83.7</td>
</tr>
<tr>
<td></td>
<td>7</td>
<td>2,585</td>
<td>65-95</td>
</tr>
<tr>
<td>Oil</td>
<td>4</td>
<td>698</td>
<td>84-87.4</td>
</tr>
</tbody>
</table>

The penalty coefficients (in €/MWh) for the violation of the constraints (7) – (11) were set at 25,000 for the energy balance, 20,000 for the primary reserve, 15,000 for the secondary reserve (both up and down) and 10,000 for the tertiary reserve. In case a surplus or deficit variable of the above constraints was assigned a positive value, the SMP was set at the price cap, i.e. at 150 €/MWh.

VI. NUMERICAL RESULTS

In this section, we present some preliminary numerical results derived by solving the DAS problem with the input data described in the previous section. We used the mathematical programming language AMPL [29] to model the DAS problem. We then solved the problem using the ILOG CPLEX 9.1 optimization commercial solver on a Pentium IV 1.8 GHz dual core processor with 1GB system memory (integrality was assigned at zero and the other parameters at their default values). The DAS problem consisted of 12,824 variables, which included 3,880 binary variables and 4,000 integer variables, and 29,264 constraints. The random numbers that were used to simulate the outages were generated using AMPL’s uniform random number generator, in which we controlled the seed.

The average computational times for the DAS problem are presented in Table VI. The computational time seems to increase with the fuel prices and decrease with the \( \text{CO}_2 \) price. To obtain the total time for the yearly scenario, the average time should be multiplied by 365. An average time for solving the yearly scenario is 4,066 seconds (a little over one hour).

```
<table>
<thead>
<tr>
<th>CO2 Price</th>
<th>Low</th>
<th>Moderate</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>14.75</td>
<td>15.62</td>
<td>16.26</td>
</tr>
<tr>
<td>5</td>
<td>13.24</td>
<td>14.60</td>
<td>15.75</td>
</tr>
<tr>
<td>10</td>
<td>10.91</td>
<td>13.07</td>
<td>14.29</td>
</tr>
<tr>
<td>15</td>
<td>8.54</td>
<td>11.06</td>
<td>12.66</td>
</tr>
<tr>
<td>20</td>
<td>6.88</td>
<td>8.74</td>
<td>11.80</td>
</tr>
<tr>
<td>25</td>
<td>6.53</td>
<td>7.21</td>
<td>9.74</td>
</tr>
<tr>
<td>30</td>
<td>7.24</td>
<td>6.91</td>
<td>8.23</td>
</tr>
</tbody>
</table>
```

In Fig. 2, we show a graph of the weighted average SMP versus the \( \text{CO}_2 \) price for the three scenarios of fuel prices.

![Fig. 2. Average SMP.](image-url)

This average is computed by weighing the SMP paid to the producers in each hour by the dispatched generation quantity in that hour divided by the total dispatched generation quantity in the entire simulation horizon and then summing over all hours (8,760) of that horizon. This value
does not include the impact of the transmission losses (which were not included in the DAS model of Section IV), or any other uplifts that are imposed on the SMP paid by the suppliers.

The impact of the CO\textsubscript{2} price on the average SMP is estimated by the slope of the linear trend in Fig. 2. This slope varies from 0.55 to 0.62, suggesting that an increase in the CO\textsubscript{2} price by 1 euro results in an increase of 55 to 62 cents on the average SMP. The graphs in Fig. 2, also suggest that a 10\% increase (high price scenario) or decrease (low price scenario) in the (natural gas and oil) fuel prices results in a 7.9\% increase and a 8.3\% decrease, respectively, in the average SMP.

In Fig. 3, we show the percentage reduction in emissions that is achieved by the increase of the CO\textsubscript{2} price, for the three scenarios of the fuel prices.

We observe that the emissions reduction is increasing in the CO\textsubscript{2} price and the fuel prices, as expected, and with an escalating rate. In general, however, this reduction is not very significant. For CO\textsubscript{2} prices up to 20\$, the reduction does not exceed 5\%, and it is almost negligible for prices of less than 10\$. This can be explained by the fact that the difference between the fuel cost of lignite units and gas units is so wide that a combination of a really high CO\textsubscript{2} price (therefore high emissions cost) and low gas prices is needed to cover this difference and cause the lignite units, which are the major CO\textsubscript{2} pollutants, to be shut down by the DAS program. In the optimistic case of a 30\$ CO\textsubscript{2} price, combined with a low gas price, the reduction can reach 13\%.

Fig. 4 shows the percentage of the total CO\textsubscript{2} cost that passes onto the system cost, i.e. onto the amount paid to the producers by the system operator (HTSO).

From Fig. 4 it can be seen that this percentage is higher for the low fuel prices scenario, because at lower fuel prices, the emissions cost becomes a relatively more important component of the variable costs. One must recall from Fig. 2, however, that in absolute terms, the total amount of emissions decreases at lower fuel prices. For CO\textsubscript{2} prices in the range of 10-20\$, the average percentage is close to 55\%. The emissions cost does not pass completely onto the system cost, because the marginal pricing used to compute the SMP is based on the impact of the marginal unit. Consequently, for the hours with low load, the lignite is setting the price and hence the impact is higher. For the hours where the SMP is set by the natural gas units, however, the impact is much lower.

The energy mix for the three scenarios of fuel prices is shown in Figs. 5-7.
From Figs. 5-7, we can observe that the lignite share remains above 50% in the scenario of high fuel prices (Fig. 7), even for the highest CO\textsubscript{2} price (30€). In the moderate case (Fig. 6), the lignite share remains practically unaltered (about 55%), for CO\textsubscript{2} prices up to 15€, and approaches 50% for a CO\textsubscript{2} price of 30€. In the low prices case (Fig. 5), the lignite share falls more rapidly, as the CO\textsubscript{2} price increases, reaching 47% for a CO\textsubscript{2} price of 30€. In all cases, lignite is substituted by natural gas.

In absolute terms, the dispatched thermal and hydro yearly energy generation is 44.749 TWh. If we include the RES injections and the net imports, the total yearly energy amounts to 52.633 TWh. The contribution of the hydro is approximately 4.8 TWh (9.1%), the RES injections are 5.256 TWh (10%) and the net imports are 2.628 TWh (5%).

The yearly emissions, in absolute terms, are approximately 44 Mtons CO\textsubscript{2} for the case of zero CO\textsubscript{2} price. A CO\textsubscript{2} price of 30€ results in a reduction of emissions of about 5.67, 3.67 and 2.52 Mtons for the low, moderate and high fuel prices scenario respectively. These reductions were shown in relative terms in Fig. 3.

Another noteworthy indicator is the average emissions per thermal MWh and per total MWh that is produced by the Greek electricity sector (including hydros and RES). The results for the three fuel prices scenarios are shown in Fig. 8.

![Fig. 8. Average emissions coefficient in ton CO\textsubscript{2} per MWh](image)

From Fig. 8, it can be seen that the average emissions coefficient is decreasing more rapidly for the low prices scenario, as expected. For the moderate case, it is slightly over 1 ton/MWh (thermal), and 0.8 ton/MWh (total), at the 30€ CO\textsubscript{2} price. For a CO\textsubscript{2} price less than 20€, the coefficient is above 1.05 ton/MWh (thermal) and 0.84 ton/MWh (total), for all three fuel price scenarios.

The results that we presented above were obtained from a single simulation run of the GEM over a horizon of 365 days. This run was based on a particular realization of random outages. We call this the “nominal” run. An inquisitive reader will wonder how the times between outages might affect the results. To explore the confidence level of our results with respect to the randomness of outages, we performed 30 different simulation runs, where in each run we used a different realization of the random outages. All runs were conducted for the same scenario of moderate fuel prices and a 15€ CO\textsubscript{2} price. The results are shown in Table VII.

<table>
<thead>
<tr>
<th>TABLE VII</th>
<th>BASIC STATISTICS OF THE MAIN PERFORMANCE MEASURES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Results</td>
<td>Nominal run Mean (of 30 runs) Standard deviation</td>
</tr>
<tr>
<td>Average SMP (€)</td>
<td>70.607</td>
</tr>
<tr>
<td>Emissions (tons)</td>
<td>43,641,212</td>
</tr>
<tr>
<td>Lignite share (%)</td>
<td>55.105</td>
</tr>
<tr>
<td>N. Gas share (%)</td>
<td>20.814</td>
</tr>
</tbody>
</table>

The results in Table VII suggest that the impact of the randomness of outages on key yearly performance measures is not too significant. This is probably due to a combination of the following facts. (a) The outages of most of the units are not very frequent. The average EFORD\textsubscript{d} for the year 2009 that we used in the simulations was calculated at 12.71% for the lignite units, 8.25% for the oil units and 6% for the CCGTs. (b) There is a large number of units that belong to the same family and have similar characteristics (e.g., there are 18 lignite units). This implies that in any particular day, the effect of the absence of a unit from its family due to an outage is small. Moreover, from fact (a), the probability that two or more units of any particular family are down is quite small. (c) Each day is independent from the previous day except for the status of the units; therefore, the energy and reserve requirements in each day must be met in that day and there is not surplus or deficit of energy or reserves, carried over from the previous day, as is the case, for example, in inventory systems.

Nevertheless, if we examine shorter time periods, e.g., months, the variance of the performance measures will be higher. To see this, we provide the relevant results in Figs. 9-12.

![Fig. 9. Monthly average SMP (right axis) with a 95% confidence interval. The monthly dispatched energy is shown in column form (left axis).](image)
The standard deviation for the monthly results is much higher compared with the yearly ones. For instance, the monthly SMP has a standard deviation ranging from 2.68 to 3.92 times higher than the one of the yearly SMP. The random outages do affect significantly the monthly outcomes; however, the aggregated yearly results have relatively small standard deviations. It is worth mentioning that the values that were obtained in the nominal run are very close to the averages.

VII. CONCLUDING REMARKS AND POSSIBLE EXTENSIONS

The key remark of this analysis is that the incorporation of the emissions cost in the generation units’ variable cost does not result in significant reduction in emissions, unless there is a combination of low gas prices and relatively high CO₂ prices. This is due to the significantly low cost of lignite, which is the primary fuel in the Greek electricity sector. CO₂ prices near 15€ in the carbon market, which is a very likely scenario for the near future, will not result in emissions reductions of more than 5% for all the three fuel price scenarios that were examined in this paper.

Nevertheless, the impact of the incorporation of the emissions cost on the electricity price is significant. With simplified calculations, every euro of the CO₂ price is going to result in an increase of about 55 cents on the average electricity price (e.g. the scenario for a CO₂ price of 15€ is likely to result in an increase of about 9€ on the average electricity price). This finding is particularly interesting and contradicts with the assumption made in [30] that the external cost will pass on the customer bills. Although [30] refers to the externalities associated with the greenhouse gases, and uses a totally different methodology, the comparison with a more detailed simulation in the context of this paper seems to be a very promising direction for the continuation of this work.

Lastly, it should be noted that the figures presented in this paper are based on an instance of the DA market. We have seen that the outages affect the monthly averages but their impact on the yearly results is smoothed. To further enhance our confidence in the results, many more scenarios need to be examined, mostly with respect to other stochastic parameters. This is left to be done in a more extended version of this work.

VIII. REFERENCES


IX. BIOGRAPHIES

Panagiotis E. Andrianesis graduated from the Hellenic Military Academy (2001), and received his B.Sc. (2004) degree in Economics from the National and Kapodistrian University of Athens, Greece. Currently, he is pursuing a Ph.D. degree in mechanical engineering at the University of Thessaly, Volos, Greece. His research interests include power system economics, electricity markets, operations research, and optimization.

George Liberopoulos received his B.S. (1985) and M.Eng. (1986) degrees in Mechanical Engineering from Cornell University and his Ph.D. (1993) degree in Manufacturing Engineering from Boston University. Currently, he is Professor of Stochastic Methods in Production Management and Head of the Production Management Laboratory in the Department of Mechanical Engineering at the University of Thessaly, Volos, Greece. Prior to joining the University of Thessaly, he was Lecturer in the Department of Manufacturing Engineering at Boston University and Visiting Researcher in the Laboratoire d’Informatique at the Université Paris IV, France. He is an Associate Editor of IEEE Transactions and Flexible Services and Manufacturing Journal. He has co-edited several collected volumes of books/journals with themes in the area of quantitative analysis of manufacturing systems. He has published numerous scientific papers in IEEE, INFORMS and other journals mostly in operations research/management and automatic control. His research interests include applied probability, operations research, and automatic control models and methodologies applied to production and operations control.

Dr. Liberopoulos is a member of INFORMS, the Hellenic Operations Research Society, and the Technical Chamber of Greece.

Pandelis Biskas received his Dipl. Eng. degree from the Department of Electrical Engineering, Aristotle University, Thessaloniki, in 1999, and his Ph.D. in 2003 from the same university. He also performed his Post Doc research from March 2004 till August 2005 in the same university. From March 2005 till July 2009 he was a power system specialist at the Hellenic Transmission System Operator (HTSO), Market Operation Department. Currently, he is a Lecturer at the Aristotle University of Thessaloniki, in the Department of Electrical and Computer Engineering. His research interests are in power system operation & control, in electricity market operational and regulatory issues, and in transmission pricing.