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# THE DYNAMICS OF THE ELECTRICITY MARKET IN GREECE

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Εγκρίθηκε από την τετραμελή εξεταστική επιτροπή

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# Abstract

The majority of electricity markets worldwide follow the trend of liberalization that initiated in the UK in the late 1980s. During the last decade, EU Directives and market pressure drove the reforms of the Greek electricity market with a view to liberalize the wholesale and retail segments. This process has been slow according to international standards and has yet to establish the desired level of competition.

The present thesis overviews significant aspects of electricity markets, as well as the current status of the Greek electricity market. Based on this review, the thesis presents a view on the basic limitations of the Greek market, and their effects on market operations and the involved stakeholders. This is followed by a set of proposals on dealing with the market limitations and on promoting a more robust, fair, market structure aligned with the national goals of economic development and green energy. The proposals focus on the ownership regime of production units, the contracting options, demand response, capacity remuneration, and the balancing market.

## Acknowledgements

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*“Desert sky, dream beneath the desert sky.*
*The rivers run but soon run dry.*
*We need new dreams tonight…”*

*U2 – In God’s Country*

# 1 Introduction

The Greek electricity market is experiencing the repercussions precipitated by the electricity sector reforms initiated in the 1980's in Chile and the UK. Until that point, electricity markets worldwide were commonly characterized by vertically integrated incumbent electricity companies that also owned the networks. However, as energy demand increased continuously and new technologies were introduced, market deregulation became a reality with several countries deciding to transition electricity markets from a fully regulated framework to liberalized schemes. The related objectives were the following:

- Enhance quality of service
- Reduce prices
- Improve resource allocation leading to improved efficiency
- Support industry through competitive electricity prices
- Allow the consumer the opportunity to select the price – quality balance by choosing a suitable supplier

Greece also proceeded to restructure its electricity market in compliance with European Directives dictating gradual deregulation of energy markets. The first milestone in the liberalization process has been Law 2773/99, which has defined the basic regulatory framework of the market until today.

Currently, Greece lags behind European benchmarks in forming a competitive liberalized market. The related market limitations are evidenced by the low penetration of new participants both in the wholesale and the retail segments. New entrants have consistently argued against the market distortions, as well as the lack of sufficient market monitoring; they openly require that the Government and the regulator address the fundamental problems limiting market development. Furthermore, along with the European Commission, the IMF has put the existing framework under pressure – in the context of promoting measures to reform pathogenic structures. In addition, the Government is committed to environmental targets, thus administrators are striving to produce a "cleaner" electricity profile.

Therefore, Greece is under pressure from both the internal and external environments to achieve an efficient market set-up.

There is great interest in studying an electricity market with the aim to develop an effective roadmap. The major point of interest is that electricity constitutes the backbone of human operations in today's life; hence an efficient restructuring of this sector can practically enhance our quality of life. Moreover, international experience provides extraordinary paradigms of original approaches, which prove that there is room for innovation answering the financial and environmental challenges that all markets are facing.

The importance of electricity and the innovation possibilities to address electricity market shortcomings are the two motives of the present thesis, which focuses on a delineation of the Greek electricity market, the steps towards deregulation, the related limitations, as well as innovative initiatives that may lead to a better future for all participants. The thesis is structured as follows:

- Part 1: The current electricity market framework
    - Chapter 2 - Regulatory framework and restructuring approaches
      *Provides an overview of the infrastructure of the Greek electrical industry, its regulatory framework, the entities involved, and the basic market structures.*
    - Chapter 3 - Current Greek market mechanisms
      *Describes the functioning of the energy and the capacity market in Greece.*
    - Chapter 4 - Generation Costs
      *Overviews the cost components for generating electricity.*
    - Chapter 5 - Alternative Energy Resources
      *Presents the various alternative energy sources, their capacity, future prospects, market pricing, and the critical areas for their deployment.*
    - Chapter 6 - Charges and billing
      *Overviews the charges for electricity services and price levels.*

- Part 2: Limitations of the Greek wholesale market and steps towards a healthier market structure
    - Chapter 7 - Limitations of the Greek wholesale market
      *Presents an analysis of the basic factors limiting all electricity markets; drills down to the limitations indigenous to the Greek market, which are imposed by market power abuse, the delay of unbundling, the shortcomings of the pricing system, and the inadequacy of capacity remuneration.*
    - Chapter 8 - Proposals for a stronger market model
      *Focuses on the current trends of the reforms in the Greek electricity market and presents proposals for an efficient ownership regime, competitive contracting between market participants, active demand response, and a reliable balancing market.*
    - Chapter 9 - Conclusions
      *Presents a general review of the thesis findings and proposals.*

# Part 1: The current electricity market framework

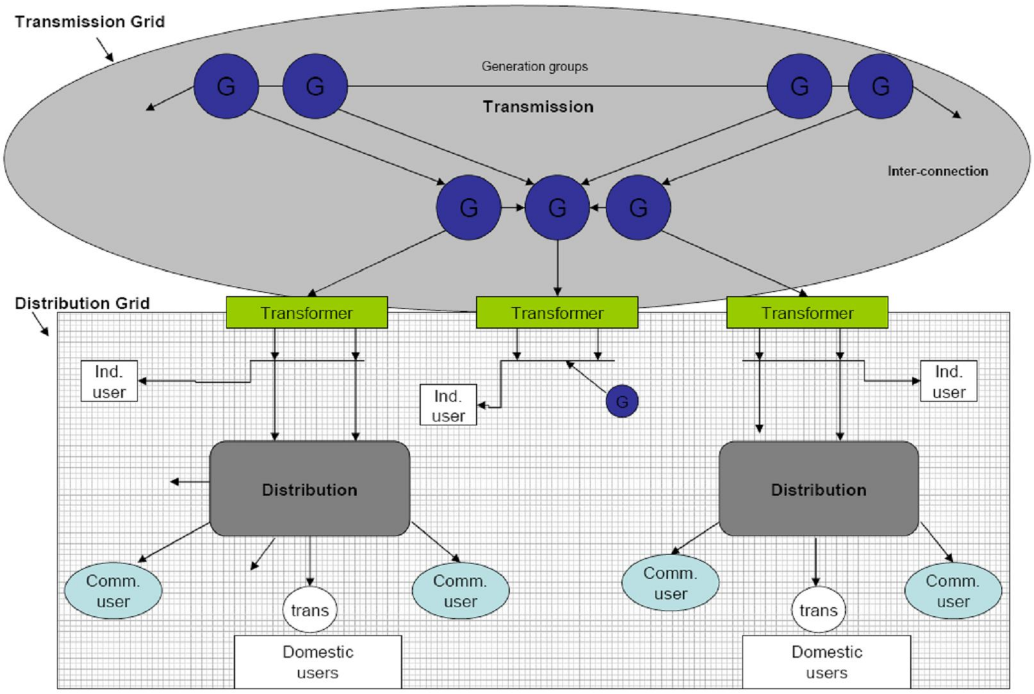
# 2 Regulatory framework and restructuring approaches

This chapter provides an introduction to the basics of the Greek electricity industry delineating its structure, the entities involved and the roles assumed. It aims to provide a clear picture of the current status of the Greek electricity market, the basic options of the market structure, and the market's current strengths and weaknesses. Specifically, Section 2.1 overviews the infrastructure of Greece's electrical power industry, Section 2.2 provides an overview of the regulatory framework, Section 2.3 presents the key organizations and agencies involved in the market, and Section 2.4 outlines the main options concerning the market structure.

## *2.1 Physical infrastructure of the electrical power industry in Greece*

A simple diagram of the Greek electricity industry is shown in Figure 2.1. Firstly, it shows the generating stations connected to a super-grid that enables the pooling of generation. The generated energy is channeled through the High Voltage (HV) transmission network with a total length of 11,092 km using overhead power lines operating at 400 kV, underwater and underground power lines at 66 kV. Some industrial customers are supplied with HV electricity (HV customers), like Aluminium of Greece S.A. Transformers are used to reduce HV to Medium Voltage (MV) of 22 kV, 20 kV, 15 kV, and 6.6 kV.

Electricity is thereafter channeled to the distribution network, which is approximately 210,000 km in total length, consisting of MV lines supplying electricity to industrial customers, large commercial premises and urban areas, transformers reducing MV to Low Voltage (LV), and, finally, LV lines providing large building blocks and commercial users with 380 V power, and small-scale users, including the domestic ones, with 220 V power (see PPC 2010).




**Source: Murray (2009)**

**Figure 2-1: Basic physical infrastructure of the Greek electricity industry**

A determinant affecting the country's physical infrastructure is a serious mismatch of power supply and demand. The majority of generating plants are in the north of the country, where the lignite fields are located, while the bulk of demand is in the south; Attica alone hosts 40% of the population and most of the country's industry.

## *2.2 Overview of the regulatory framework*

The first milestone towards a liberalized electricity market in the European Union was Directive 96/92/EC. Its provisions established the first governing principles towards market opening, including a) the introduction of the concept of "eligible customers", who could freely choose their supplier (at least 1/3 of the market in 2003), and b) administrative unbundling of network activities, generation, and supply (Weigt, 2009).

The instructions of Directive 96/92/EC have been applied in Greece with Law 2773/99 which defines the normative framework of the liberalized electricity market. The main directions embedded in this law are the following (Kollias, 2008):

- Creation of the Regulatory Authority of Energy (RAE), an independent authority having the following duties and responsibilities (Iliadou 2008):
  - Advisory duties: Proposing measures, issuing simple or binding opinions over secondary legislation, licensing and regulated tariffs
  - Decision making: Imposition of fines, approval of implementation of the prescribed Codes that determine the normative framework of electricity market, issuance of decisions in case of complaints against parties involved – for instance in 2009 EGL issued a denunciation of the way HTSO applies the Grid and Exchange Codes, particularly in what concerns its engagement about providing information about the market operation and thereafter RAE arbitrated discussions between the parties involved
  - Dispute settlement between consumers and market participants, or between market participants and companies managing networks
  - Monitoring and reporting regarding market performance and the security of supply.
- Creation of the Hellenic Transmission System Operator (HTSO) S.A. for the interconnected system, a majority state-owned company, as 49% of its shares belonging to PPC, with two principal responsibilities a) to guarantee the balance between generation and consumption, the reliability, the safety and the quality of the electricity supply, and b) to settle market transactions, much as an energy stock market that arranges on a daily basis debits and credits of participants.
- The Public Power Corporation becomes an anonymous company corporation (Société Anonyme), with the state holding 51% of the shares, and holds exclusively the ownership and operation of the distribution network and the ownership of the transmission network
- Gradual implementation of the customers' right to choose supplier, starting with 30% of the customers, i.e. 450 large customers consuming more than 2 GWh/ year
- Issuance of a license issued by the Ministry of Development consultation with RAE for generating and supplying energy
- Regulated Third Party Access, i.e. the access of new entrants to the incumbent's network infrastructure
- Liberalization of Renewable Energy Sources (RES) production and cogeneration, which consists the production of both electricity and useful heat by a power station

More substantive rules have been enacted by the EU with Electricity Directive 2003/54/EC. In an attempt to encourage convergence of member states, this Directive reduces the freedom of choice of governments on liberalizing electricity markets and shortens the deadlines of enforcing its directions.

- All non-household customers are to become eligible from July 1, 2004
- All consumers are to become eligible from July 1, 2007
- Legal unbundling for transmission to become effective after July 1, 2004
- Legal unbundling for distribution to become effective after July 1, 2007

The European Commission's 2007 benchmarking report (European Commission, 2007) showed that in spite of partial progress among member states, its legislation was in general poorly implemented. As a result, in September 2007 the Third Legislative Package was proposed by the EC and included rigid rules to trigger concerted action. It prescribed the following (Weigt, 2009 & Euractiv, 2009):

- In terms of the implementation of unbundling, it presented three options: a) Unbundling of ownership, which dictates separation of electricity networks from businesses generating power; this is the most preferable option, as it promotes complete liberalization. b) The State designates a body (which must be independent from the incumbent company) to make the investment and commercial decisions related to the transmission system; this agency is termed the Independent System Operator (ISO). c) The creation of an independent company charged with the daily management of the grids; this is the Independent Transmission Operator (ITO) and may belong to the integrated incumbent company, while the latter must abide by certain regulations, like being object to supervisory body, comply with a program and being monitored by a compliance officer, in order to ensure Operator's independency.
- In terms of the regulating bodies, it prescribed harmonization and strengthening of the powers and duties of the regulators, ensuring regulator independence, and mandating cooperation between regulators. For this purpose, a European agency was created for the coordination of energy regulators.

- Establishment of a European Network for Transmission System Operators (TSOs) with a view to harmonize standards of grid access, to ensure coordination of operation, and planning of network investments, including interconnections.

The extend to which the aforementioned normative instruments have affected member states is under continuous scrutiny. In the meantime, there are still key issues to be resolved, such as meeting environmental goals.

Similarly to economies oscillating from liberal to regulated regimes, there has been a reorientation towards re-integration of participants that fail to compete effectively and re-regulation to address deficiencies. The formation of a successful electricity market is a continuous procedure that strives to ensure the robustness and flexibility of the energy system. Different countries present different structures and challenges; there is no one-size-fits-all optimal model. Several approaches put in practice provided powerful test beds for countries like Greece.

## *2.3 Organizational entities of the Greek Electricity market*

According to the current implementation of the above EC directives, the entities involved in the Greek electricity market are the following:

- The **Transmission and Distribution Owner** (TDO) who builds, owns and maintains the super-grid system comprising transmission lines and the distribution network, transformers and reactive compensation equipment. In Greece the Transmission and Distribution Owner is PPC, the country's incumbent.
- The **Hellenic Transmission System Operator (HTSO)** who operates the transmission system. Its basic objective is to maintain quality, stability and the security of supply in real time.
- The **Generators (Generation Companies or Gencos)** who plan, build, own, operate and maintain generation; the latter may feed into the super-grid network or, if smaller, may be connected directly into the local distribution network.
- The **Suppliers** or Load Representatives who supply energy to the system's eligible customers after contracting. They can be traders, individuals, self-supplying consumers, producers declaring demand at all events, or PPC. PPC is also the exclusive supplier for non-eligible customers.

❖ The **Regulatory Agency for Energy (RAE)** charged with market surveillance and monitoring.

The Greek electricity industry is dominated by the vertically integrated **PPC**, in which the Greek government holds a majority stake as well as the management. For the first half of 2010, PPC generated 78% and supplied 97.4% of the country's electricity. These rates are continuously, but slowly, decreasing as other participants gain market power. Regarding its distribution activity, in October 2010 PPC's board of directors decided to establish a new subsidiary company to own and manage the distribution network; this is an attempt to comply with the obligation of legal unbundling of the distribution from the incumbent.

Demand in Greece follows an increasing trend, which is the common case for most countries worldwide. The increasing appetite for electricity necessitated the encouragement of investments in generation. On the other hand, there is no active demand-side participation in reducing energy consumption. The only case concerns a limited number of industrial customers, who reduce their consumption during peak hours, when electricity prices are high (RAE, 2009). Table 2-1 shows the respective power and energy consumed for several countries including Greece.

**Table 2-1: Electricity generation 2008**

| Electricity | Demand/consumption (TWh) | Peak Load (GW) | Max. net generation capacity (GW) | Total net generation volume (TWh) |
|---|---|---|---|---|
| Bulgaria | 34,64 | 7,03 | 8,07 | 39,64 |
| Cyprus | 4,996 | 1,01 | 1,189 | 4,719 |
| Czech Republic | 72 | 10,88 | 17,724 | 77,09 |
| Denmark | 36,2 | 6,3 | 12,7 | 34,7 |
| France | 494,5 | 84,4 | 117,7 | 549,1 |
| Germany | 569 | 76,8 | 147,1 | 599,3 |
| Great Britain | 351,37 | 59,2 | 79,9 | 359,02 |
| Greece | 55,68 | 10,393 | 11,871 | 56,87 |
| Ireland | 27 | 4,873 | 6,013 | 26,7 |
| Italy | 339,5 | 55,3 | 86,9 | 307,065 |
| Luxembourg | 6,703 | 1,071 | 0,598 | 2,68 |
| Norway | 127,4 | 21,589 | 30,811 | 142,667 |

**Source: European Commission (2010)**

New entrants, known as Independent Power Providers (IPPs), emerged investing in efficient generation technologies, including: a) Combined Cycle Gas Turbines (CCGT), which incorporate a gas turbine generating electricity and upgrade the generation efficiency using the waste heat to produce steam, which, in turn, feeds a steam turbine to produce additional electricity. b) Open Cycle Gas Turbines (OCGT), which are gas turbines that operate exhausting the residual heat to the atmosphere, c) Combined Heat and Power (CHP), i.e. power stations generating electricity and useful heat simultaneously, and d) Renewable Energy Resources (RES), such as wind, sunlight, geothermal heat and tidal energy. The most significant generating companies are depicted in Table 2-2.

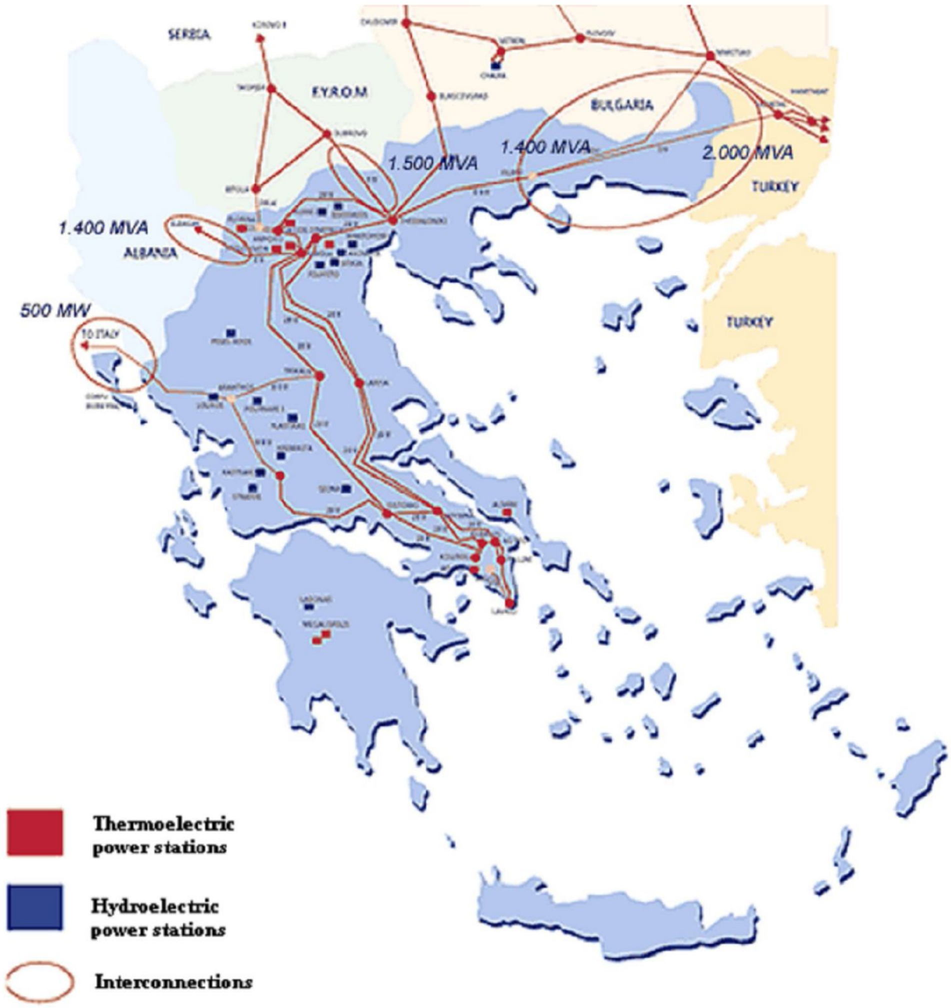
**Table 2-2: The most powerful generating companies in Greek market**

| Company | *Available Capacity* | *Future Investments* |
|---|---|---|
| PPC | 12.760 MW | |
| Ellaktor (RES) | 86 MW<br>107 MW under construction | Estimation: 180 MW until end of 2010<br><br>License obtained for additional 96 MW |
| Elpedison | 812 MW | Target: 1.500-2.000 MW power portfolio |
| Endesa Hellas | 334 MW<br>444 MW | 437 MW under construction |
| Enelco | 900 MW | |
| GEK Terna - GDF | 147 MW<br>435 MW | |

Greece participates in international trading using 400 kV interconnections with all neighboring countries, namely Albania, FYROM, Bulgaria and Italy, while Turkey has been interconnected with Greece since September 2010. The transfer capacity of the interconnection lines is allotted to traders through auctions held once a year by the HTSO. The right to interconnector capacity can be traded.

The number of trading companies being able to participate in these auctions is increasing; in June 2008 there were 17 companies participating, whereas in June 2009 the companies rose to 21. These are PPC, Heron Thermoelectric, Edison, Iberdrola, Neco, EGL Hellas, Atel Austria, Blue Aegean Energy, EDF Trading, Danske Commodities, et al.

As for the traded capacity, during the first 5 months of 2009 exports reached 1,227,826 MW, with the vast majority of 942,378 MW provided to Italy. Second export country was Albania with 285,312 MW, while small quantities were destined to FYROM (133 MW) and Bulgaria (3 MW). On the other hand, imports during the same period were 3,039,748 MW, the greatest part coming from FYROM (1,553,365 MW), followed by Bulgaria (1,308,414 MW), Italy (118,803 MW) and Albania (59,166 MW). Figure 2-1 presents the map of the international interconnections of the Greek electricity grid together with their trading capacity (IEA, 2006 & Kalaitzoglou, 2009).)




**Source: PPC (2010)**

**Figure 2-2: Map of the international interconnections of the Greek electricity grid.**

As far as supply is concerned, sixty-one (61) companies were listed in the participants register in March 2010. Gaining respectable market power in retail market consists a challenge; the tariff structure allows PPC to supply electricity for domestic customers even below cost price and compensate through high prices for MW industrial and commercial users. Notwithstanding, tariff structure was revised towards a more balanced scheme in September 2010. As The new suppliers have been trying to reach industrial and commercial consumers. The 3 suppliers actively participating in the retail market are

1) Verbund serving supermarket chains, Casino Parnitha, Praktiker, Fourlis, Alpha Bank, etc,
2) Aegean Power serving Carrefour, Jumbo, Sprider, Ster cinemas, etc and
3) Elpedison Trading serving Eurobank, Grecotel, Viohalco, etc,.

## 2.4 Basic market structure options

This Section presents basic market structures in order to gain a perspective over various types of entities' relations in a deregulated market framework. Countries around the world have been implementing these different market structures tailored to their resources, market maturity and governing principles. Loi Lei Lai (2001) suggests that new trading structures can be conceptualized and modeled taking into consideration the three categories discussed below.

*The Pool*

In the pool model, competition is initiated in the generation business. Subsequently, competition is gradually brought to the distribution side, where retailers could be separated from Distribution Companies (Discos), and, thus, consumers could be allowed to phase in a choice of retail supply. In this model, the transmission system is centrally controlled by a combination of an independent system operator (ISO) responsible for grid operation and a power exchange (PX) responsible for trading in spot and derivatives market, i.e. the market handling the short-term delivery of electricity and the future contracts for delivery of electricity, respectively. The ISO handles the transmission part of the market operation, whereas the PX is charged with the financial operation of the market. The combination (ISO + PX). is often called the Market Operator (MO), is disassociated from all market participants, and ensures open access to these participants. The MO holds auctions, in which a) generators place offers, for a dispatch period, and b) buyers can place demand bids for the same period. Since all participants are obliged to participate to the Pool for any power transactions, this model is often called Mandatory Pool.

Specifically, in the pool system,

- Generators and importers submit offers for every dispatch period – an hour in case of Greece – of the next day. These offers comprise essentially a pair of quantity Q in MW and a price P in €/MWh (per hour).
- Load representatives, i.e. suppliers, self-supplying consumers and exporters, submit demand bids for every dispatch period too to purchase electricity at or below a certain price.

Thereafter the MO ranks the offer bids in an offer curve by increasing price, while it ranks the demand bids in a demand curve by decreasing price. The intersection of the demand and the offer curves sets the market price – all generators that offered bids lower than the market price are scheduled to inject energy, while all buyers that offered demand bids higher than the market price are scheduled to be served. The market price is the price that all generators are paid to for their production and that all buyers are paying for their energy consumption. The mechanism for determining the generation schedule per unit and the related tariffs is described in more detail in the next Chapter.

Scheduled generation may need to be altered in order to avoid exceeding physical constraints or respond to contingencies. Consequently, it is common for a generator inside the schedule to be constrained off and be paid its lost profit, or for a generator outside the schedule to be brought in and be paid bid price. This uncertainty entails risk for generators and suppliers. Moreover, the deregulated market involves risk related to price volatility due to fuel availability, low elasticity of demand and a steep generation supply curve. Participants need to get some protection against these risks; therefore hedging contracts become a major option. These are particularly popular in the England and Wales under the name **“Contracts for Difference” (CfDs).** These contacts are between generators and buyers who trade directly in the pool. Both parties agree upon the price of a specific quantity of energy, called the strike price. The generator undertakes to sell to the buyer a schedule of power at specified prices. A buyer with such a contract is still bound to buy all the energy needed to meet its demand through the pool and pay for all the energy it buys at the market price, like all buyers. At the same time a contracted generator submits offer bids to the pool and gets paid for any scheduled generation of it at the market price, like all generators. This means that a contracted buyer is buying the energy it needs, including the contracted one, whether the respective contracted generator has been scheduled to produce or not (Rothwell & Gómez, 2003 & Murray, 2009). In the end there two possible transactions taking place:

1. If the contract strike price is higher than market price, the buyer pays the difference between these two prices to the generator.
2. If the market price is higher than contract strike price, the generator pays the difference between these two prices to the buyer.

In the first case generators are hedged against low payment for producing energy, due to low market prices, whereas in the second case suppliers are hedged against having to buy electricity at prices sizably higher than the prices they charge for selling electricity to their customers.

Although every physical power transactions is held inside the pool, agreements upon the contract strike price and payments for differences take place outside the pool. Obviously a CfD is of a purely financial nature and not a technical one.

In order to better understand the practicality of CfDs, it is useful to go over a relevant example. Assume the following:

- ❖ A generator bids into the pool for a specific day at a price of 25 €/MWh
- ❖ The pool price is calculated to be 30 €/MWh
- ❖ A supplier has placed a CfD with the generator for a fixed quantity of 100 MW for this day under consideration at a price of 28 €/MWh.

Since the market price is higher than the generator's bid, the generator is scheduled to run. According to the above prices

- ➢ The generator gets paid by the pool for 100*24MWh at 30 €/MWh, i.e. 72.000€,
- ➢ The supplier pays the pool for the energy it takes at 30 €/MWh, i.e. 72.000€ also.
- ➢ Outside the pool the generator has to repay the supplier the difference between the CfD strike price and what was paid into the pool by the supplier, i.e. 100*24*(30-28) = 4.800 €.

The net price paid by the supplier is then 72.000€-4.800€ = 67.200€.

This is equivalent to a unit price of 67.200 / (100*24) = 28 €/MWh[1], i.e. the contract strike price.

Figure 2-3 depicts the Mandatory Pool scheme.

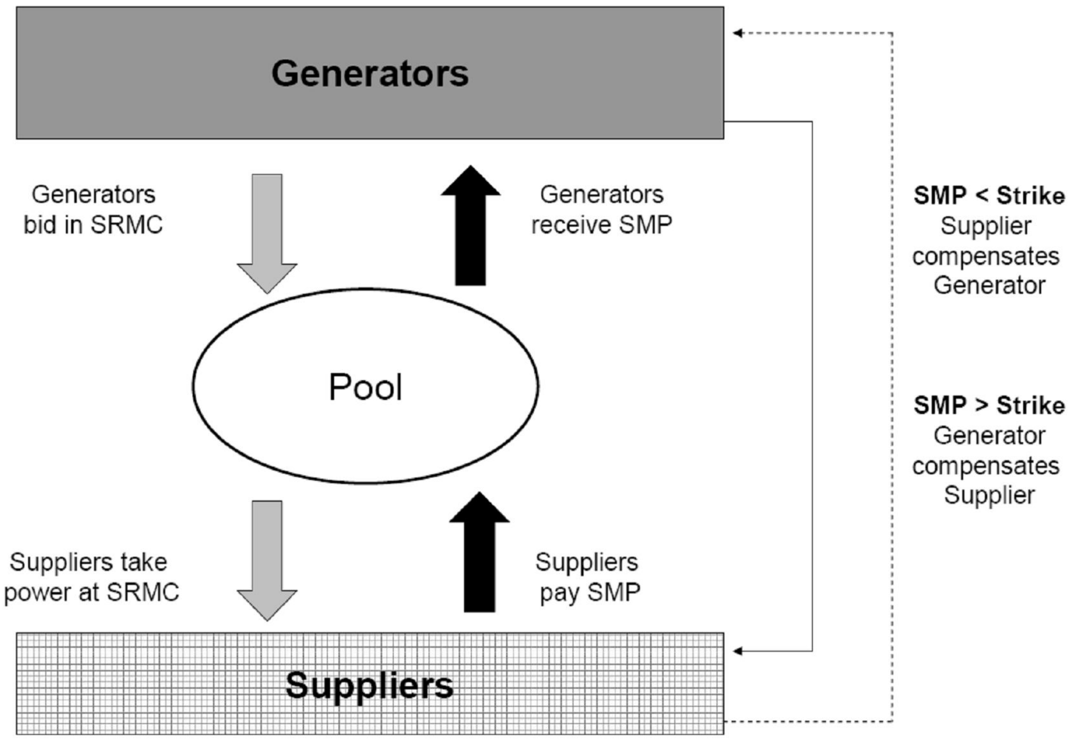



**Figure 2-3: Mandatory Pool**

Greece's current market structure is a mandatory pool; the restructuring models in Chile, Argentina, Spain, and East Australia also fall into this category with some modifications to the basic structure. Figure 2-4 depicts the Greek electricity market.

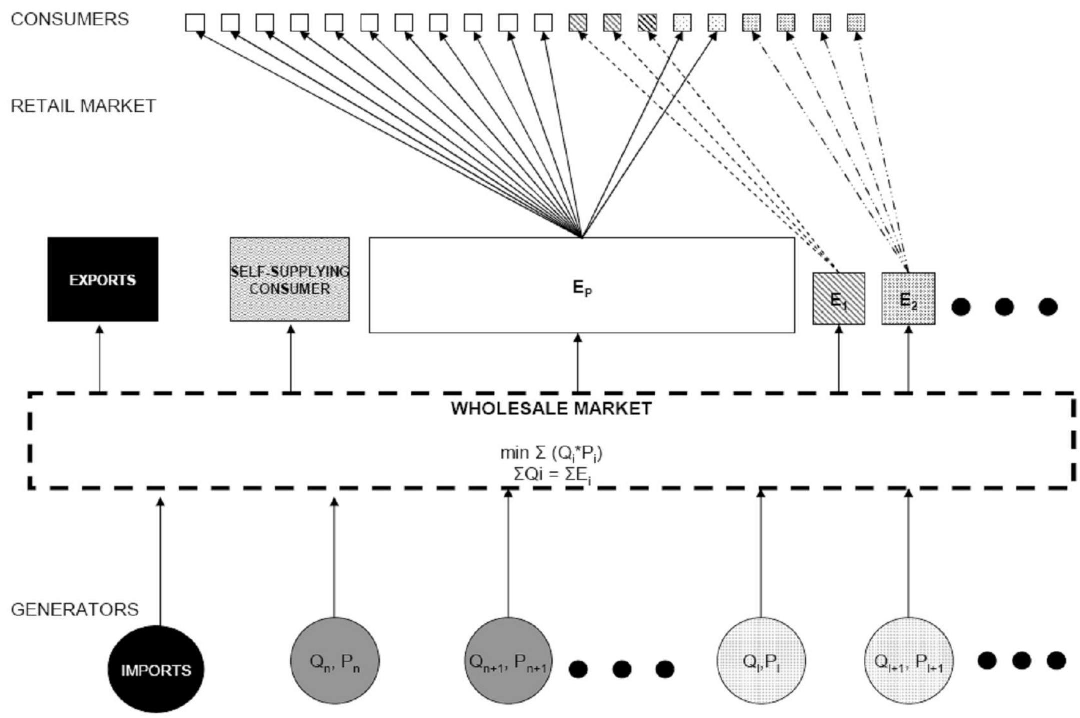



**Figure 2-4: Greek electricity market**

*Multi Market or Net Pool (Bilateral Trading + Balancing Market)*

The most likely arrangement to emerge in practical systems in the future is that of a Multi Market (see Fig. 2.4). Whereas the Pool model requires all energy to be traded through the pool, for the Multi Market model, central bidding is optional and in practice it formalizes the CfDs. The Multi Market model consists of three basic mechanisms:

- ❖ A pool, in which the ISO is responsible for system operation and guarantees system security; transactions take place at the day-ahead stage or earlier, with information passed to the System Operator so that physical constraints are taken into account.
- ❖ Bilateral contracts formed outside the pool between market participants, with a generator agreeing to deliver a schedule of power to a buyer at a certain price. The difference with the CfDs is that bilateral contracts are not only financial instruments, but have a physical manifestation; a bilateral contract releases the buyer from participating in the pool and guarantees the generator's entry in the generation schedule, as schedulers give priority to contracted generators to supply

the energy they have agreed. Consequently, all financial and physical transactions are confined between the parties.

- Balancing Market (BM). Finally, since in practice the level of demand and the availability of generation cannot be accurately predicted, the BM is used to clear the residual energy and any un-contracted demand. In this market, generators place bids over adjusting (increasing or decreasing) their production, while suppliers or consumers place bids over adjusting their demand, so that production ultimately matches demand. The System Operator accepts them in a lowest price order, in order to balance the system at least possible cost.

Representative cases of such a system are California, Nord Pool (the common financial market for Denmark, Sweden, Norway and Finland), New Zealand, New York Power Pool (NYPP) and PJM (the common market for Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia).

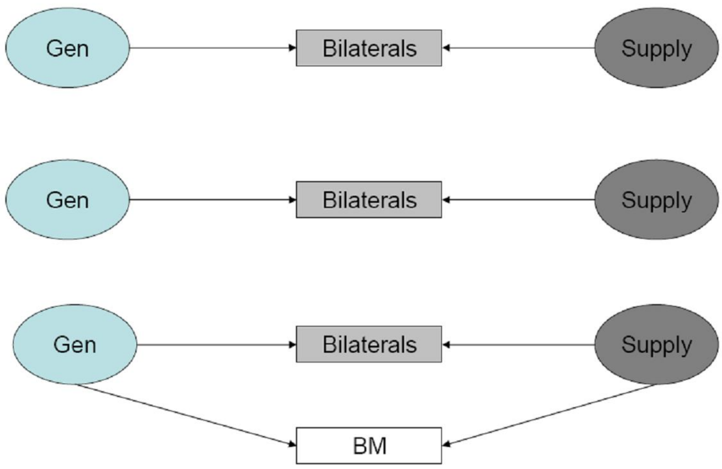



**Figure 2-5: A schematic representation of the multi market**

*Multilateral trades*

Multilateral trades are a generalization of bilateral transactions where a System Coordinator, or power broker, puts together a group of energy producers and buyers to form a balanced transaction. In this case also, a power pool will coexist with multilateral and bilateral transactions. For example, multilateral trading can involve a group of customers, such as steel industries, and a group of generators providing them electricity satisfying their specific demand needs.

The extreme case in this model is where the concepts of pool and the PX disappear. In this case, each market is managed by a System Coordinator, or a broker, under its individual rules. The ISO interferes in contracted dispatch only when the physical network operation is to be distorted. Many of new participants will have constructive role in promoting competition, since there is more flexibility in choosing schemes for buying and selling energy. The principle weakness is the danger of price volatility and market instability. UK, always being in the forefront of electricity market deregulation, has adopted this system since 2007. Finally, this model of the future for Greek electricity market, as European Union is placing great emphasis on market integration through consociating European countries' electricity markets and the multilateral model might be the one best serving such a diverse market.

# 3 Current Greek market mechanisms

The Greek deregulated market is subdivided in two different market types:. a) The Day Ahead Market, in which the actual electricity transactions take place, and b) the Capacity Market, also known as Capacity Adequacy Mechanism, where generators are remunerated for ensuring long-term capacity availability. Both mechanisms are described in this Chapter.

## *3.1 Entities and related roles in market operation*

The entities participating in the market have already been presented in Section 2.1. The different objectives, requirements, and roles related to these entities are discussed in the current Section.

**Generators** participate competitively in the generation side of the market ensuring customer choice in short and long term.

A critical issue for generators is their need to have access to the national as well as cross-borders grid without any discrimination and be able to offer their services under fair rules. Furthermore, energy prices should not be distorted by factors outside the market, like uneven regulated tariffs, but should be defined outright by the actual demand and production cost. In that case, increasing electricity prices indicate an increasing need for installment of extra capacity; therefore prices constitute long-term signals for generators deciding about future investments and provide incentives for further investments. Finally, all generators should have acceptable market power, without one dominant company affecting market operation.

The **HTSO** is responsible for the physical flow of electricity, and for securing that transmission does not impose any discrimination to any party involved, and that it is cost-reflective. HTSO is also responsible for scheduling the generation units. Significant challenges, to be addressed include a) the provision of investment incentives stemming from price signal or regulation , and b) ensure HTSO independence from PPC, which was the previous transmission operator.

**RAE** monitors the market, guaranteeing healthy competition and the common welfare. It also issues opinions and proposed measures for all issues concerning the energy market. RAE is seeking a more active role, in line with international regulating authorities, which are increasingly involved in designing the normative framework of the energy market along with governments. This more active role is especially important for the Greek market, since RAE is the only independent and credible entity to support effective re-regulation.

The **Suppliers** deliver electricity to consumers. Their objective is to grant reliable energy delivery and provide value for money for their customers. They also require access to market without discrimination. Supplier operation is heavily influenced by the framework of the market. A significant role is to protect their customers from the effects of possible distortions in other parts of the market.

The **end-consumers** are on the receiving end of the market, demanding services tailored to their needs. There are domestic, industrial or commercial customers with present various load profiles and demand levels. End customers require continuous physical availability of electricity at affordable prices that reflecti value.

## *3.2 Composition of the Greek electricity market*

The Greek electricity market consists of two distinct markets: a) The long-run availability energy market [Capacity Market], and b) the short-run wholesale energy and ancillary services market, the Daily Ahead Market (DA) [Energy and Ancillary Services Market].

### 3.2.1 Capacity Market

This secondary market compensates generators for standing ready to produce and is a prime source for generators to recover their capital costs. The reasons for the adoption of this market are:

- To address the imparity of market power – there is an apparent disadvantage of new generators who use new technologies of generation and have to recover their capital costs vis-à-vis the incumbent company

- ❖ The intrinsic structure of Greece's liberalized market – participants are unable to recover capital costs through their offer bids as is the case in mature liberalized markets.
- ❖ Risk mitigation for both suppliers and generators – the short-term risk of generators lowers with capacity payments; thus, prices for suppliers are guarded against large fluctuations.
- ❖ Generation availability constitutes a service, therefore it should be offered at a cost.

Broadly speaking, the function of the capacity market comprises the repayment of generators by suppliers for offered capacity. As a result on the one hand the generators are defrayed for offering power availability, and on the other hand the suppliers fulfill their legal obligation to prove their capability to cover the needs of their customers in terms of capacity, known as Capacity Adequacy Obligations.

On the generation side, the Greek Capacity Adequacy Mechanism involves the publication of annual Capacity Availability Tickets (CATs) for production license holders. These certificates relate to the real power availability of each unit as assessed by the System Operator. The tickets are submitted to the CAT Register, kept by HTSO, and constitute a call to the suppliers for the conclusion of respective contracts, named Capacity Availability Contracts (CACs). With these contracts suppliers and generators agree upon the terms of capacity payments. Suppliers and generators are also able to proceed to bilateral financial agreements between them in the form of Contracts for Differences (CfDs) or call options.

A supplier not covering his obligations is charged with the Non Compliance Penalty, which is set by RAE yearly. This payment is currently at 35,000 €/MW of Available Capacity. This value defines automatically the price cap for the available capacity, as the maximum value of the latter ends up being equal to the Non Compliance Penalty.

Considering the possible difficulty in the inclusion of CACs between parties, a Transitional Mechanism was offered, enabling suppliers and generators to form CACs with HTSO instead of each other. All participating generators receive a regulated price per MW of Availability, which is equal to the Non Compliance Penalty; the respective cost is distributed amongst the participating suppliers. It is worth noting that so far all participants in the capacity market chose the Transitional Mechanism (RAE, 2009).

When electricity market moves to a more mature stage, participants are expected to form bilateral agreements between them – without HTSO intermediation – in order to take part in the capacity market more competitively, so as to seek greater profits. For instance, since the Non Compliance Penalty will possibly rise in the next few years, a supplier could reach an agreement with a generator to cover his Capacity Adequacy Obligations for the next two years in a slightly higher price than the current Non Compliance Penalty, possibly at 38,000€/MW per year. This is a way in which the supplier could hedge against the risk of the increase of the Non Compliance Penalty in a truly competitive market.

### 3.2.2 The Day-Ahead (DA) Market

The Day-Ahead (DA) Market, or Energy and Ancillary Services Market, or Wholesale Market defines how units operate for every hour of the dispatch day in order to minimize the generation costs and achieve market balance. It is subdivided into three different markets, which are overviewed below. Note that all financial settlements for energy transactions are conducted in the day before the day when the physical energy transactions take place; this is why this market is called Day Ahead.

Figure 3-2 illustrates the Greek wholesale electricity market. On the day ahead, injectors, i.e. producers, importers, hydro and RES, are mandated to place their energy and reserve offers, their techno-economic declarations defining the features of the units they are using to offer energy, and non-availability declarations in case they are unable to offer energy for the dispatch day. At the same time load representatives place their demand bids. The Day Ahead Schedule is settled for energy and reserves. On the dispatch day Real Time Dispatch takes place. Finally on the day after the Imbalances Settlements clears the transactions.

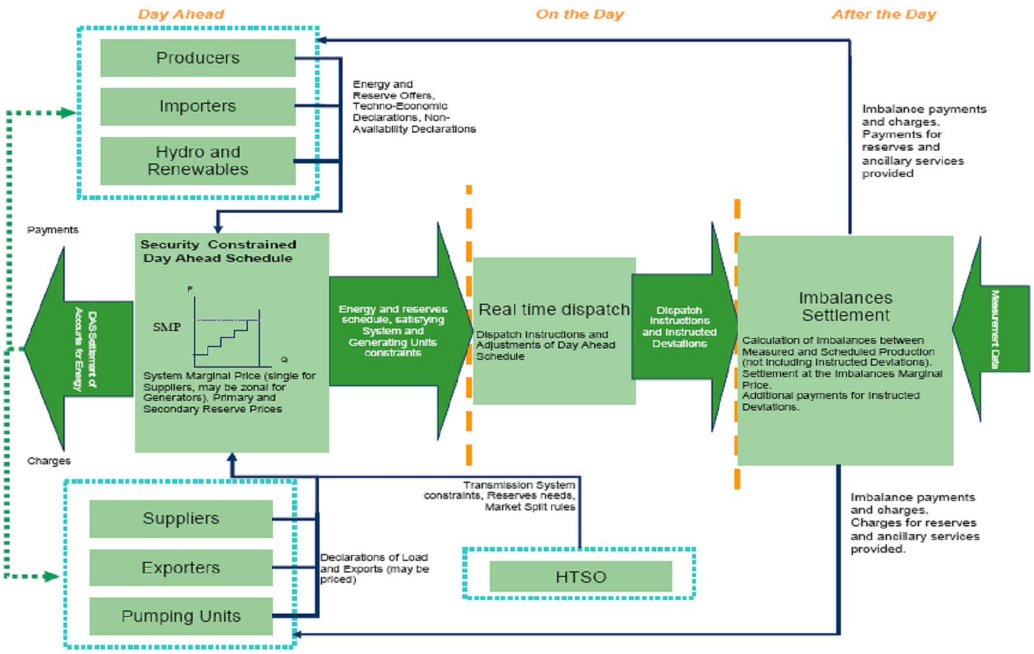



**Figure 3-1: Greek wholesale electricity market (*RAE, 2009*)**

## The Energy Market

The objective of the Energy Market is to construct an optimal schedule of operation for the generation units, for the exchanged energy and for ancillary services in terms of cost, while complying to all physical constraints and reserve requirements. Ultimately, the electricity demand should be satisfied every day.

In the Energy Market, every day, generators place bids (€/MWh) for generating energy, while load representatives place demand bids (€/MWh) for all 24 hour periods of the next day. After the gate closure at 12.00 pm, the HTSO solves the DA problem, which consists of setting the market price (per hour of day), while at the same time defining the generators and the suppliers to participate in the market (for the particular hour), and scheduling the generators to produce and those to offer ancillary services.

Figure 3.1 illustrates how the prices are set in the DA market. In this Figure, the x- axis is the MW that the generator has to offer at each dispatch hour, the y- axis is the bid price (in €/MWh) that participants offer. In the Figure two curves are drawn. The first comprises of a series of line segments parallel to the x-axis. Each line segment represents a bid, i.e. a pair of power offered and bid price; its length is equal to the former, while its position with respect to the y-axis corresponds to the latter. The offers are sequenced in ascending price order. This curve is called the merit order (red steps in Fig. 3.1) and represents the order of dispatching electricity in the electricity market. In a direct analogy, the line segments of the second curve represent the demand bids, i.e. pairs of power demand and bid price. In this case the bids are sequenced in descending price order. The point when the two curves meet defines the System Marginal Price (SMP) and is the market settling price. This is the price that

- suppliers have to pay for the energy they expect their customers will need and
- importers and generators get paid.

The following quantities and parameters are also shown in Fig. 3.1

- inelastic demand: this is total declared demand, except from demand for exports and pumping units
- consumer's surplus: the financial

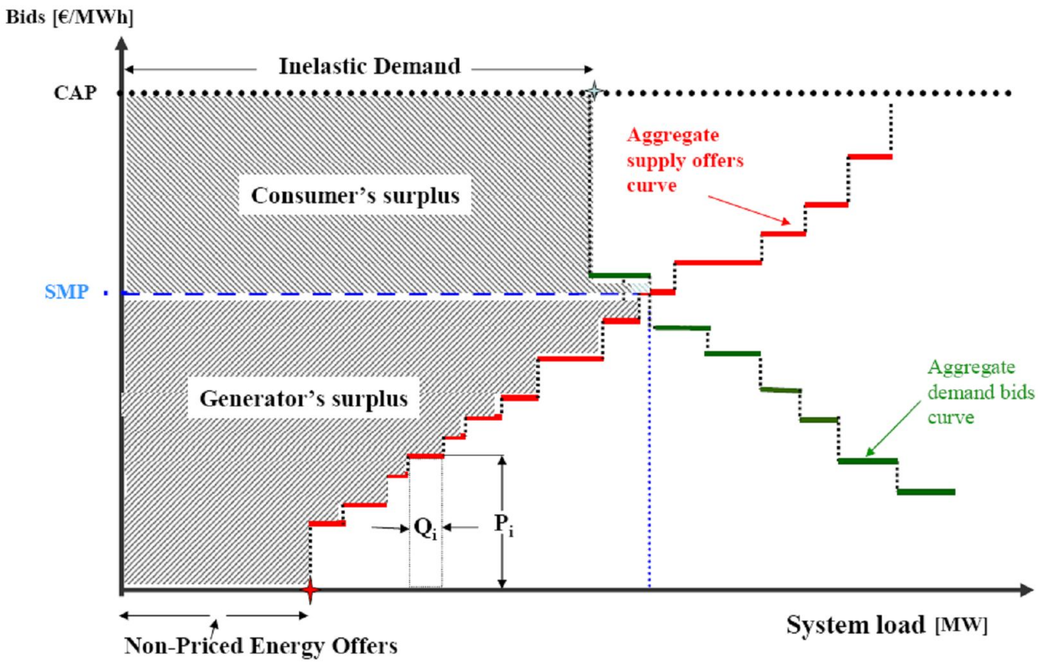



**Figure 3-2: Greek Day Ahead demand-offer matching (Lekatsas 2009. p. 4)**

**Energy Reserves Market**

To ensure the quality and reliability of electricity supply there are extra services provided, called the ancillary services. These services are provided by generators to the HTSO at prices either set by RAE, or through a tendering process, as described below. The different categories of ancillary services described in the "Grid Control and Power Exchange Code for Electricity" (RAE, 2010a) are the following:

1. System Primary Control: The collective automatic response of generating units and loads to deviations of the real system frequency from the reference frequency, in an attempt to stabilize frequency and to balance the total generation with the total energy absorption within 30 seconds from the distortion occurrence.
2. Primary Control Reserve: The change of the generated Active Power for a frequency deviation of ±200 mHz from the reference frequency so that the System Primary Control can take place. it consists ac response of the unit's automatic regulation of rotation.

3. System Secondary Control or Load Frequency Control (LFC): An automated system, the Automatic Generation Control (AGC), used by HTSO to manage the deviation between generation and demand, as well as the system frequency in time intervals of 10 to 15 minutes after the deviation occurrence.
4. Secondary Control Reserve (negative and positive reserve): The deviation margin for active power of a unit joining the AGC.
5. System Tertiary Control: The regulation taking place periodically within a few minutes (established by the HTSO) in order to restore the System Secondary Reserve level, if this has changed as a result of the operation of the System Secondary Control.
6. Tertiary Control Reserve: The margin of change for active power generated between 90 seconds and 15 minutes after the relevant instruction in order for the System Tertiary Control to take place.
7. Unit Tertiary Spinning Reserve: The Unit Tertiary Control Reserve for a unit synchronized in the system.
8. Unit Tertiary Non-Spinning Reserve: The Unit Tertiary Control Reserve for a unit not synchronized with the system.
9. Interruptible Load Ancillary Service: The possibility to automatically interrupt load supply for a given customer, with view to contribute to regulating frequency through the provision of a respective reserve.
10. Generation Pick Up Ancillary service: The possibility for automatic rapid generation pick up or the response of pumping units.
11. Standing Energy Reserve Ancillary Service: The maximum active power quantity that can be provided by a synchronized unit within a period between 20 minutes an 4 hours. System Standing Reserve is the sum of the Standing Reserves of the units that have been, or may be, scheduled to provide such service for each dispatch period.
12. Voltage Control: The preservation of voltage within normal operation limits, which requires sufficient standing and dynamic active power reserve by a) using system devices, b) changing tap positions of Unit Transformers and c) controlling manually or automatically the active power generation of units locally or centrally.

For all these services, there are generating units that form contracts with the HTSO. The service price is defined by RAE or by a tendering process. Otherwise, generators submit offers in a market conducting ancillary services issues, called the Reserves market. Their bids have the form of a pair of €/MW price and MW quantity for Primary and Secondary Reserve.

**Market mechanism for the allocation of the production near the points of consumption (Zonal pricing)**

This market mechanism provides motives for installing new units as near as possible to consumers, to the extent that this is necessary. HTSO a) charges northern generators higher yearly system use charges than those for all other generators, while b) it rewards southern generators by giving them higher reimbursements than northern generators for hours congestion of the transmission system; specifically when the available transmission capacity from North to South is not adequate to satisfy all desired transactions.

Finally, it is important to mention some other mechanisms that contribute substantially in the market processes. These are the Real Time Dispatch Operation and the Imbalances Settlement.

The **Real Time Dispatch operation (RTD)** is charged with dispatching every 5 minutes generating units already scheduled by the DA market in order to satisfy the demand side at a minimum cost, while securing the system reliability. This function is formulated as a linear program, having as objective the minimization of generation costs and several constraints, including the matching of the load for the next 5 minutes interval, compliance with generation units' technical constraints, network constraints, and reserve requirements.

The **Imbalances Settlement** includes the clearing of transactions with respect to energy deviations (instructed or uninstructed), Ancillary Services and Uplift Accounts. In this context HTSO calculates debit/ credit for each participant regarding the participant's energy deviations and payments for the Uplift Accounts.

The Imbalances Settlement procedure is defined as an administrative procedure. It does not correspond to a Balancing Market, where participants may place bids to decrease or increase their scheduled activity so that the market is balanced. In this context:

- ❖ The Imbalances Settlement clears at a uniform price, the Imbalances Marginal Price. The problem of defining this price is solved like the DAS, except that the actual data are taken into account, namely the actual electricity consumption and the actual units availability.
- ❖ HTSO, in its capacity as the Market Operator, should ensure that the cost of the Imbalances is allocated to the partiers that cause them.
- ❖ HTSO should also aim towards the minimization of the total Imbalances Settlement cost.

The Imbalances Marginal Price is calculated hourly using the DA Schedule algorithm, while considering the actual availability of the units, RES generation, as well as the load that was absorbed. Moreover, all instructed deviations by the producers are paid at least at their marginal cost. The Imbalances Settlement procedure is completed within 4 days following the dispatch day (RAE, 2009).

# 4 Generation Costs

This chapter introduces the structure of basic generation costs including capital costs, fuel costs, as well as the operating efficiency of generating units. The motivation for discussing generation costs, is that price formation and limits in energy offers are determined by these costs; therefore the latter constitute a major determinant for the market function and for investment decisions among current and prospective participants.

## *4.1 Cost components*

The costs that arise for operating generators, and, thus, need to be recovered through participating in the energy market, include:

**Capital costs** of constructing the plant. Capital costs depend on the mixture of debt and equity used to finance construction, the life expectancy of the installation, and the related debt rates.

**The variable cost of fuel** used for the operation of the unit. Cost of fuel is related to market rates and includes the transport costs to the plant. Comparing the two major fuels used in power units in Greece (i.e. gas and lignite), gas cost and transport involve complex issues, even political, as Greece procures gas from foreign countries, in contrast to lignite, which is more straightforward, since Greece disposes sufficient deposits. Table 4-1 quantifies the mixture of fuels used for electricity generation in Greece. As shown in the Table 4-1, the latter depends heavily on lignite, used to cover mainly the fixed load in power supply, known as base load. An important fact is that 1,150 of the 5,288 MW of installed lignite power capacity corresponds to older plants, and PPC is currently considering their replacement or refurbishment. Natural gas was introduced to the Greek energy system after 1996. During the last decade new combined cycle natural gas generation units were commissioned, and part of the old oil-firing plants have been transformed to natural gas generation. As a result, the share of natural gas in total electricity generation showed a significant increase from 5.1% in 1999 up to 21% in 2007, while oil decreased from 18.8% down to 6%.

**Table 4-1: Installed capacity in the interconnected system as of 31.12.2008**

| Plant type | Net Installed Capacity (MW) | % |
|---|---|---|
| Lignite | 4808.1 | 38.69 |
| HFO (Heavy Fuel Oil) | 718.0 | 5.78 |
| GTCC (Gas Turbine Combined-Cycle) | 1962.1 | 15.79 |
| Natural gas – other | 486.8 | 3.92 |
| Hydro plants | 3016.5 | 24.27 |
| RES and small Cogeneration | 993.5 | 7.99 |
| Large-scale CHP (Combined Heat&Power) | 334.0 | 2.69 |
| Other Cogeneration | 108.0 | 0.87 |
| **Total** | **12427.0** | **100.00** |

**Source: RAE (2009)**

The installed capacity of renewable energy sources is still very limited, with wind and solar power being the frontrunners. Although Greek law since 2006 refers to hybrid schemes (combined generation from energy sources, with at least one being RES), there has not been any progress in this sector. Cogeneration plants are limited in number and capacity, and are linked with industrial applications (RAE, 2009; IEA, 2006).

**Fixed operating costs**, include staff costs, transport, procurement costs –except fuel- including spare parts, lubricants, supplies and consumables, communication, insurance etc. (Murray, 2009). Note that some of these operational costs relate directly to plant utilization, such as maintenance materials and the associated labor costs, while others do not, such as staff costs other than maintenance.

The cost category having the most impact in price formation is **the marginal cost**, since it is used to determine energy offer limits. This is the cost of producing a particular unit of output. The marginal cost of producing the first unit includes *all* of the fixed costs and *some* of the variable costs. There is a distinction between the short-run marginal cost (SRMC) which includes variable costs such as fuel and raw materials, without the cost of capital or other fixed production costs, and the long-run marginal cost (LRMC), which refers to both variable and fixed costs of production over a long period (Rothwell& Gómez, 2003).

Regarding the capital costs of units in Greece, there is a capacity payment that contributes to cost recovery. In other more developed markets, generators manage all cost recovery through sales – a scheme of this kind, known as energy-only market, requires healthy competition, sound planning and detailed estimation of the utilization and of the price bids.

Regarding fuel costs, the Greek power generation system is benefiting from the use of low cost lignite, leading to one of the lowest ratios of fuel cost over total generation cost in Europe. Notwithstanding, this ratio is deteriorating because of the increasing marginal cost of lignite units and the costs to be added as of 2013 for $CO_2$ emissions.

## 4.2 Operating efficiencies

As mentioned above, Greek generation is significantly affected by the ageing of power plants owned by PPC, particularly the lignite plants and the old open cycle oil and gas plants. This unit mix maintains the average thermal efficiency at low levels.

Combined Cycle Gas Turbine (CCGT) units of high thermal efficiency debuted in the Greek market a few years ago and they are expected to be the first choice for new investments to come. Therefore the average thermal efficiency is due to rise.

Non-fuel components of operation costs as a ratio to total power cost are largely inefficient in Greece. Ratios such as labor costs per MW, operation and maintenance costs per MW and network costs per MW are all clearly above the European average (Iliadou, 2008).

# 5 Alternative energy resources

Renewable Energy Sources (RES) have been traditionally employed in production for Greece. The country is rich in various renewable resources of high potential, but, unfortunately, it does not exploit them to a great extent. Their role is all the more vital as the country struggles to meet the 20-20-20 EU target, i.e. reducing greenhouse gas emissions by 20%, increasing energy efficiency by 20% and augmenting the RES production to 20% of the total generation. The following sections delineate the different RES in Greece, their potential, the mechanisms used for pricing and providing incentives for their further development, as well as the critical areas for RES deployment.

## *5.1 Competing sources*

Greek market made its first important legal step towards RES development with Law 2244/1994, enacting subsidies, significant tax deductions, and guaranteed prices for some years in favor of investing in and operating RES. These incentives boosted greatly the investments in the sector, giving rise to sizable wind and active solar power. In 2006, tariffs were established for various technologies with Law 3846/2006; it specifically aims to an increase of solar energy and introduces new moderately higher tariffs for offshore wind generation. Tariffs were altered again in 2009, decreasing the emphasis on photovoltaics (PVs) so as to balance falling PV installation costs. At present, the legislative framework promotes the renewable resources largely unexploited, including geothermal energy, biogas, and biomass. Furthermore, for the first time in Greek legislation, a tendering procedure is instituted for the construction and operation of offshore wind farms and the designation of environmentally acceptable areas for those constructions. In the near future, Law 3851/2010 will amend the tariff system and the duration of contracts with RES producers, aligning with the present market status.

Table 5-1 depicts the capacity increase per type of licensed RES plants in Greece for the last decade, and Table 5-2 presents the RES for electricity in several European countries including Greece.

**Table 5-1: Licensed RES capacity (in MW) during the 2000s**

| RES TYPE | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|---|
| WIND | 226 | 270 | 287 | 371 | 472 | 491 | 749 | 846 | 1,022 | 1,140 |
| BIOMASS | 1 | 22 | 22 | 22 | 24 | 24 | 24 | 39 | 40 | 41 |
| SMALL HYDRO | 42 | 45 | 45 | 50 | 59 | 64 | 77 | 95 | 158 | 180 |
| PHOTOVOLTAIC (PV) | 0 | 1 | 1 | 1 | 1 | 1 | 5 | 9 | 12 | 37 |
| **TOTAL** | **269** | **338** | **355** | **444** | **556** | **581** | **855** | **989** | **1,232** | **1,398** |

**Source: General Secretariat for Energy and Climate Change (2009)**

**Table 5-2: Electricity from RES – Gross electricity consumption – 2007 (in %)**

| | Total share | Hydro | Wind | Biomass | Solar | Geothermal | 2010 Objective |
|---|---|---|---|---|---|---|---|
| **EU-27** | **15.6** | **9.2** | **3.1** | **3.0** | **0.112** | **0.2** | **21.0** |
| **EU-25** | **15.5** | **8.9** | **3.2** | **3.1** | **0.115** | **0.2** | **21.0** |
| **DK** | 29.0 | 0.1 | 18.8 | 10.1 | 0.005 | | 29.0 |
| **DE** | 15.1 | 3.4 | 6.4 | 4.8 | 0.496 | | 12.5 |
| **EE** | 1.5 | 0.2 | 0.9 | 0.4 | | | 5.1 |
| **IE** | 9.3 | 2.3 | 6.6 | 0.4 | | | 13.2 |
| **EL** | 6.8 | 3.8 | 2.7 | 0.3 | 0.001 | | 20.1 |
| **ES** | 20.0 | 9.3 | 9.2 | 1.2 | 0.171 | | 29.4 |
| **FR** | 13.3 | 11.4 | 0.8 | 1.1 | 0.003 | | 21.0 |
| **IT** | 13.7 | 9.1 | 1.1 | 1.9 | 0.011 | 1.5 | 25.0 |
| **NL** | 7.6 | 0.1 | 2.8 | 4.6 | 0.030 | | 9.0 |
| **AT** | 59.8 | 51.4 | 2.9 | 5.5 | 0.024 | 0.0 | 78.1 |
| **PT** | 3.5 | 1.5 | 0.3 | 1.7 | | | 7.5 |
| **UK** | 5.1 | 1.3 | 1.3 | 2.5 | 0.003 | | 10.0 |

**Source: European Commission (2007)**

At the beginning of 2010 the installed capacity of RES in Greece, excluding large hydro, comes up to barely 1,180 MW of wind and approximately 70 MW of PV. PPC runs 15 large-scale and 7 small-scale hydro schemes with a combined installed capacity of 3,066 MW and of nominal output of approximately 4.4 TWh per year. PPC also holds a license for two geothermal resource fields with a potential electrical capacity of 170 MW, which are expected to be developed in the future. RES investments for 10,000 MW have been licensed, with only 1,300 MW of them put in operation, while 34,000 MW under licensing procedure; RAE (2009). PVs have evolved dramatically through 2009, reaching growth rates of 200% per trimester, which is expected to continue even after 2012.

RES, including large hyrdros, have provided 13% of gross electricity consumption in 2010; this is comprised of 4% by wind farms and small hydros and 9% by large hydros (RAE, 2009 & Ministry of Environment, Energy & Climate Change, 2010).

EU Renewables Directive 2001/77/EC set quite high targets for Greece: 20.1% and 29% of generation by renewables by 2010 and 2020, respectively. Consequently, the country has to adopt more drastic measures to meet these targets. Unfortunately, for 2010 the electricity production from renewables is approximately 15%, a result that coincides with the worst case scenario according to the RES deployment modeling of the Center for Renewable Resources (CRES) (General Secretariat for Energy and Climate Change, 2009).

In October 2010, the Minister of Environment, Energy and Climate Change published a decision regarding the intended fuel mix of RES. Table 5-3 describes the respective data.

**Table 5-3: Intended proportions of installed capacity/ gross electricity generation (in MW)**

| | 2005 | | 2010 | | 2011 | | 2012 | | 2013 | | 2014 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | GWh | MW | GWh | MW | GWh | MW | GWh | MW | GWh | MW | GWh |
| **Hydro:** | | | | | | | | | | | | |
| *<1MW* | 26 | 106 | 29 | 112 | 30 | 116 | 31 | 120 | 32 | 123 | 33 | 127 |
| *1MW-10MW* | 63 | 218 | 154 | 593 | 160 | 617 | 166 | 641 | 168 | 647 | 179 | 689 |
| *>10MW* | 3018 | 4693 | 3054 | 4283 | 3054 | 4330 | 3236 | 4599 | 3396 | 4838 | 3396 | 4839 |
| *of which pumping* | 700 | 593 | 700 | 776 | 700 | 777 | 700 | 774 | 700 | 772 | 700 | 773 |
| **Geothermal** | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 123 |
| **Solar:** | | | | | | | | | | | | |
| *photovoltaic* | 1 | 0.9 | 184 | 242 | 357 | 470 | 531 | 698 | 778 | 1022 | 1024 | 1345 |
| *concentrated solar p.* | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Tide, wave, ocean** | | | | | | | | | | | | |
| **Wind:** | | | | | | | | | | | | |
| *onshore* | 491 | 1267 | 1327 | 3129 | 1924 | 4501 | 2521 | 5838 | 3119 | 7116 | 3716 | 8427 |
| *offshore* | | | | | | | | | | | | |
| **Biomass:** | | | | | | | | | | | | |
| *solid* | | | 20 | 73 | 20 | 73 | 20 | 73 | 20 | 73 | 20 | 73 |
| *biogas* | 24 | 94 | 40 | 181 | 40 | 182 | 50 | 183 | 60 | 184 | 80 | 364 |
| *Bioliquids* | | | | | | | | | | | | |
| ***TOTAL*** | 2923 | 5786 | 4107 | 7838 | 4885 | 9513 | 5856 | 11379 | 6872 | 13232 | 7767 | 15215 |
| ***Of which in CHP*** | | | 20 | 73 | 20 | 73 | 20 | 73 | 20 | 73 | 20 | 73 |

**Source: General Secretariat for Energy and Climate Change (2009)**

## *5.2 Market Pricing*

RES belong to the so called non-priced offers. This means that the Operator is forced by law to include all offers of RES producers to the energy dispatch. Moreover the Operator is obliged to purchase RES electricity at regulated prices that work as subsidies for RES generators, known as feed-in tariffs .

Feed-in tariffs are the chosen incentive scheme for many countries. In the Greek market they secure a stable price for RES producers for a 12-year period, which may extent to 20 years. In view of the targets for 2010 and 2020 the Ministry of Environment, Energy & Climate Change adjusted the feed-in tariffs as shown in Tables 5-4 and 5-5. Note that tariffs are different for the interconnected system and the non-interconnected islands.

**Table 5-4: Feed-in tariffs valid for 2009**

| Production source | (€/MWh) | |
|---|---|---|
| | Mainland | Non-interconnected islands |
| Wind energy | 87.84 | 99.44 |
| Off-shore wind energy | 104.84 | |
| Small Hydro electric plants < (15) MWe | 87.84 | 99.44 |
| Photovoltaics < (100) kWpeak<br>Photovoltaics > (100) kWpeak | 454.73<br>404.20 | 505.25<br>454.73 |
| Solar energy form units other than PV < (5) MWe<br>Solar energy form units other than PV > (5) MWe | 284.84<br>244.84 | 284.84<br>264.84 |
| Geothermal energy, biomass, landfill gases sewage treatment plants and biogases | 87.84 | 99.44 |
| Other RES | 87.84 | 99.44 |
| High efficiency cogeneration of heat and electricity | 87.84 | 99.44 |

**Source: Ministry of Environment, Energy & Climate Change (2010)**

**Table 5-5: Feed-in tariffs set by Law 3851/2010, valid as from June 2010**

| Production source | (€/MWh) | |
|---|---|---|
| | Mainland | Non-interconnected islands |
| Wind energy > 50 kW | 87.85 | 99.45 |
| Wind energy < 50 kW | 250 | |
| Small hydro electric plants < (15) MWe | 87.85 | |
| Photovoltaics in households or small enterprises < (10) kWpeak | 550 | |
| Solar thermal energy | 264.85 | |
| Solar energy with storage system | 284.85 | |
| Geothermal energy of low temperature | 150 | |
| Geothermal energy of high temperature | 99.45 | |
| Biomass ≤ 1 MW | 200 | |
| Biomass > 1 and ≤ 5 MW | 175 | |
| Biomass > 5 MW | 150 | |
| Landfill gases sewage treatment plants and biogases ≤ 2 MW | 120 | |
| Landfill gases sewage treatment plants and biogases > 2 MW | 99.45 | |
| Gas from biomass ≤ 3 MW | 220 | |
| Gas from biomass > 3 MW | 200 | |
| Other RES | 87.85 | 99.45 |

**Source: Ministry of Environment, Energy & Climate Change (2010)**

## *5.3 Critical areas in RES deployment*

Greece is gifted with an abundance of renewable resources. Although solar and wind energy installations were quickly launched, there are still great opportunities untapped. The extension of the use of RES in electricity generation is both desirable and necessary, as RES provide a sustainable and environment-friendly way of producing energy and also help achieve the country's targets for 2020. Critical areas regarding the advancement of RES are development barriers and policy forming, which are analyzed next.

A significant *development barrier* of new renewables capacity is the allocation of wind potential across Greece; locations rich in renewable resources are usually poor in grid capacity. For instance, maximum mean wind velocity throughout Greece is recorded in the Aegean islands, which are not connected with the mainland grid serving the vast majority of consumers. Another important development barrier is local resistance, which has prevented the upgrade of the grid at the aforementioned regions planned by HTSO and PPC. Thus, apart from licensing procedures, another administrative barrier is the lack of spatial planning, which could, in turn, mitigate local opposition.

*Policy* issues include the priorities posed regarding the resources exploited, and, therefore, the respective feed-in tariffs. For example, wind power feed-in tariffs and their application period may need to be revised, given that wind power has already amassed considerable know-how and that the cost of wind technologies has been reduced. In addition, wind power investments are further supported by capital grants and tax incentives, and in the future by the introduction of European Union Emissions Trading Scheme (EU ETS). Therefore, it is possible that the existing uplifting extents until after amortization and results in oversubsidization (IEA, 2006). Recently, new tariff structure legislation has encouraged investments on sources other than wind and solar.

Finally, an issue currently under discussion is the HTSO's source of funding for feed-in tariffs. The RES law dictates a renewable energy levy proposed by RAE and set yearly by the Ministry of Environment, Energy & Climate Change. This mechanism aims to cover the cost of RES electricity production, which is much higher than production based on conventional fuels, and to reward producers for offering cleaner energy to the community. The RES levy is charged to all customers according to their consumption. In practice, the comparatively low levy levels together with low SMP have inflicted total losses of several million euros in the Operator. A solution currently under discussion is transferring part of the payments for ERT S.A. (the public broadcasting corporation) that are incorporated in regulated invoices to the account subsidizing RES generators.

# 6 Charges and billing

## *6.1 Charges for network use*

Transmission and distribution networks play a fundamental role in the electricity market, since they facilitate market operation and enable participants to get connected to the system. Network owners and operators are compensated for their activities through tariffs imposed on system users. This chapter analyses briefly those tariffs.

### 6.1.1 Transmission charges

PPC owns and maintains the High Voltage transmission network, although HTSO is accountable for planning and budgeting the transmission system in Greece. The Transmission Operator has in particular the following responsibilities (Rothwell & Gomez, 2003):

1. Accommodating new generators
2. Providing for robust long-term competition
3. Maintaining reliability

Considering investments in generation versus transmission.

In this context, PPC annually constructs a 5-year plan for the development of the transmission network. This plan includes the development projects, the progress timeframe and the estimated costs. The plan is subsequently approved by the Ministry of of Environment, Energy & Climate Change following RAE's opinion, and it becomes available to investors in order to inform their related decisions.

When a new unit is added to the transmission network (except from RES units), the TSO assesses the fixed costs for the new connection. The connection is then constructed by PPC. Fixed connection costs are charged to the generator, while the connection is PPC's property (PPC, 2010). Additionally, referring to congestion, it evaluates forecast demand over a 5-year period and assesses the ability of the system to serve the expected load to identify potential weak points, while determining the necessary system development to secure reliable and economic operation (RAE, 2009).

As the owner of the transmission network, PPC receives a yearly payment for maintaining and expanding the transmission network for other participants to use. This payment is used by PPC to cover the network operation and maintenance costs, yearly depreciations of its fixed assets, as well as the annual yield of the transmission capital employed. Payments are disbursed annually by the Transmission System Operator (TSO). The TSO receives the respective sum by apportioning charges for the use of the transmission network to consumers, dividing them in three categories: i) Consumers connected to the System, ii) consumers with remote meters, and iii) all other customers connected to Low Voltage.

Regulation allows HTSO to recover its costs through transmission charges imposed to the network users, including PPC. The levels of these fees are approved by RAE annually. Generated and imported load has to carry 15% of the charge, whereas demand and exported load carries the rest 85%. The generation/import load charges vary among 3 geographic zones that reflect the current zonal imbalance of generation and demand load in Greece. As a result, this charge is 0 for Attica generators, moderate for Peloponnesus, and high for northern Greece (IEA, 2006).

Generators fund fully the connection of their new units into the network; they also fund reinforcements of the grid system, if required. These projects may be implemented by PPC, as the grid owner, or by the generator. Specifically for RES producers, whose installations are often in locations of poor grid capacity, if reinforcement work leads to grid capacity improvements beyond those required by the producer, a recovery mechanism is applied. This mechanism charges new connections within 5 years of reinforcement with appropriate fees. In this manner, some of the funds are finally reimbursed to the original developer of the reinforcement work.

### 6.1.2 Distribution charges

In their effort to abide by European Directives dictating legal unbundling of network Operators, the PPC board of directors decided in October 2010 to establish a subsidiary distribution company belonging 100% to PPC (Christodoulakis, 2010). The new company will operate the distribution network, provide distribution services and become the Operator of non-interconnected islands. The responsibilities of the HTSO regarding the distribution system will be the following (RAE, 2009):

1. Security of the network
2. Technical soundness and economic efficiency
3. Quality of voltage and supply reliability
4. Access to network
5. Connection to network
6. Measurement system and measuring
7. Providing information to network users
8. Contracting the network owner (PPC) for the development of the network.

With regards to the cost of distribution, according to Murray (2009), a typical cost makeup for a large distribution company consists primarily of the costs of operation and maintenance of assets (42%), followed by capital related costs (28%). Other costs are tax/public service costs and network losseswhich are higher in distribution than in transmission networks. The full cost has to be recovered through tariffs for system use.

Each year, PPC imposes distribution tariffs to customers according to the annual budget of system costs, after RAE's opinion and the Ministry's approval. RAE's 2011 tariffs are as shown in Table 6-1.

**Table 6-1: Tariffs for distribution system use (excluding HV)**

| Customer category | Capacity tariff | Energy tariff (cents/kWh) |
|---|---|---|
| MV (non-agricultural) | 1.303 €/MW max. demand in peak zone monthly | 0.33 |
| LV over 25kVA with reactive power measured | 4.14 €/kVA for agreed capacity yearly | 1.70 |
| LV over 25kVA with reactive power not measured | 3.65 €/kVA for agreed capacity yearly | 1.93 |
| LV domestic | 0.59 €/kVA for agreed capacity yearly | 2.17 |
| Large families and vulnerable groups | - | 2.41 |
| Other LV | 1.80 €/kVA for agreed capacity yearly | 1.93 |

**Source: RAE (2010c)**

## 6.2 End user charges and billing

The basic motivation for restructuring the electricity market was the establishment of lower prices for users through healthy competition. The results at an international level are inconclusive, as the evolution of prices has been influenced by external factors, such as fuel price fluctuations, generation technology progress and demand level increases. In Greece's case, prices have been additionally distorted especially by cross-subsidization between customer categories; e.g. lower than cost tariffs are offered to most domestic clienst and to all agricultural clients. These tariffs are offset by higher tariffs for commercial and industrial clients. This tariff imbalance has left room for new suppliers to compete only for the commercial and industrial customer segments, and has impeded the evolution of a healthy retail market.

A major legislative step towards rectifying this situation has been the ministerial decision of 2007 prescribing for PPC the following (RAE, 2009):

a) Unbundling of the various services (generation, transmission, distribution, supply)
b) Cost reflectivity and removal of cross-subsidization between consumer categories
c) Choice of tariff structures which better match consumer load characteristics in the most economic way
d) Providing incentives for consumers to improve their load characteristics
e) Transparency in order to remove barriers for new entrants
f) Maximization of the long-term benefit to the consumer and general consumer protection
g) Optimization of the use of existing assets
h) Coverage of Public Service Obligation (PSO), which consists of i) the apportionment of the cost difference of providing electricity to the consumers of the non-interconnected system, so that all consumers of the electricity market face the same tariffs, and ii) supporting lower tariffs for large families.

The remainder of this chapter presents the price structure for consumers in the Greek electricity market, as well as the various charges imposed.

### 6.2.1 The electricity bill

The consumer electricity bills in Greece include various charges structured in a rather confusing way, thus failing to meet internationally acceptable regulatory standards. This is because PPC collects the charges for several other agencies; the PPC bills include municipal taxes and charges for ERT, the public broadcasting corporation. Until recently all charges were integrated in the bill, and, thus, end users were unable to distinguish the charges for different services. As a result, consumers did not have enough information so as to choose the supplier that serves them best, while suppliers faced difficulties in acquiring clients.

The first step taken towards a rationalized structure of the electricity bill was the ministerial decision of 2007 discussed above.

PPC in an attempt to comply with this decision provides a charges analysis to its customers separated in the following parts:

- Charges for the use of the transmission network: Charges for operation, maintenance and development costs for the HV transmission system, ancillary service charges, and other charges dictated by law for a smooth market operation, for managing the transmission system and for securing capacity adequacy
- Charges for the use of the distribution network: Charges for operation, maintenance and development costs for the MV and LV distribution network – they consist of a fixed charge for the agreed supply capacity, and a variable charge which is proportional to consumption
- PSO charges explained above
- RES special tariff: As explained in Chapter 5, this tariff funds RES electricity production and adjusts the difference between the price for RES production and the wholesale electricity price.

In the same context, all suppliers present the same kind of analysis in their customer invoice.

### 6.2.2 End user energy prices

In the Greek retail market the low and medium voltage tariffs remain regulated by the Government for PPC, while high voltage customers are able to negotiate their tariffs with all suppliers, with PPC remaining the main retailer for HV.

RAE is currently asking PPC to rationalize the tariff structure for HV customers. Inasmuch as PPC provides uniform tariffs for all HV consumers, RAE asks for adjustment of tariffs according to client characteristics, such as load curve and way of repayment. RAE maintains that uniform tariffs are not compatible with the required liberalization of HV charges. Moreover, RAE asked PPC to proceed with price negotiations with HV customers, until 01/01/2011; despite the normative framework, PPC initiated HV price increases without consulting with the customers, provoking vigorous reactions from the latter.

In reference to the prices for the rest of the consumers, the Ministry of Environment, Energy & Climate Change has announced in October 2010 a new tariff system for customers. The Ministry's primary goal is to enforce asymmetric measures in order to alleviate disparities due to by the tariff structure. The new tariff system, to be implemented from January 2011, will increase domestic charges up to 13.7%, while agricultural charges will be also increased by 7%. On the other hand, the industrial and commercial customers will generally benefit through tariff reductions. Table 6-1 presents in detail the new tariff structure.

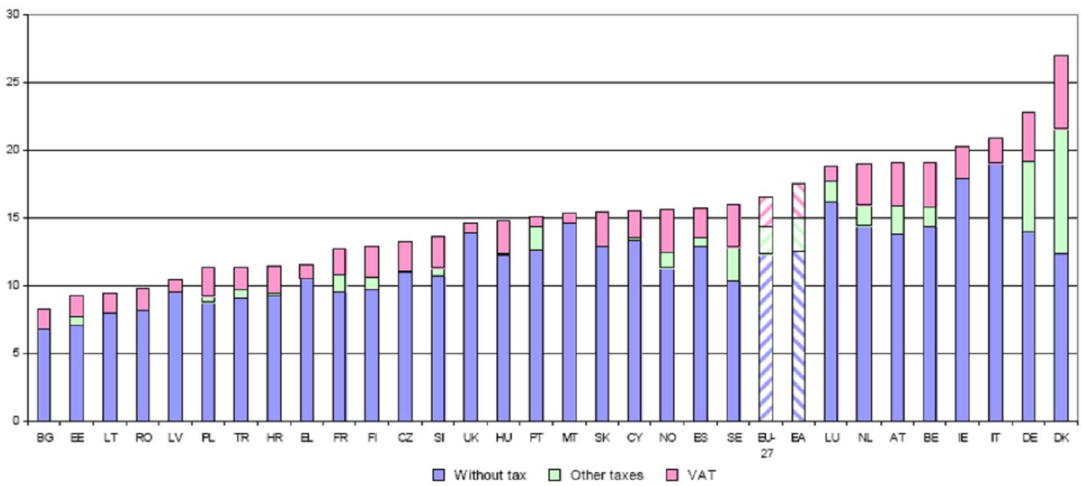
**Table 6-2: Current and new PPC invoice charges** (VAT included, municipal taxes and ERT not included)

| Current PPC invoice categories for medium & low voltage | New PPC invoice categories | Current mean charge (€/1000kWh) | Mean charge as of 1/1/2011 (€/kWh) | Total charge difference |
|---|---|---|---|---|
| **MEDIUM VOLTAGE** | | | | |
| B1 (Commercial) | General-Power+Energy | 116.7 | **106.6** | -8.7% |
| B2 (Commercial) | | 131.1 | **119.8** | -8.6% |
| B1B (Industrial) | | 96.2 | **101.1** | 5.1% |
| B2B (Industrial) | | 115.4 | **125.4** | 8.7% |
| Agricultural MV | Agricultural | 54.2 | **58.1** | 7.0% |
| **LOW VOLTAGE** | | | | |
| C21 (Commercial) | Energy | 172.3 | **160.2** | -7.0% |
| C21B (Industrial) | | 160.3 | **150.9** | -5.9% |
| C22 (Commercial) | Power+Energy | 155.2 | **148.6** | -4.3% |
| C22B (Industrial) | | 145.5 | **154.5** | 6.1% |
| C23 (Commercial) | Day+Night | 156.7 | **127.9** | -18.4% |
| C23B (Industrial) | | 128.1 | **110.9** | -13.5% |

| Current PPC invoice categories for medium & low voltage | New PPC invoice categories | Current mean charge (€/1000kWh) | Mean charge as of 1/1/2011 (€/kWh) | Total charge difference |
|---|---|---|---|---|
| Public lighting | Lighting roads and squares | 116.1 | **114.2** | -1.7% |
| Agricultural LV | Agricultural | 63.9 | **67.1** | 5.0% |
| **kWh (consumers)** | **DOMESTIC DAY-NIGHT** | | | |
| 0-800 (3,200,000) | Total Domestic (Day&Night) | 98,6 | **112.1** | 13.7% |
| 801-1000 (450,000) | | 118.2 | **121.3** | 2.6% |
| 1001-1200 (410,000) | | 119.8 | **123.0** | 2.7% |
| 1201-1600 (840,000) | | 121.6 | **124.9** | 2.7% |
| 1601-2000 (440,000) | | 129.8 | **131.8** | 1.6% |
| 2001-3000 (320,000) | | 158.1 | **151.0** | -4.4% |
| 3000 kWh< (90,000) | | 176.6 | **152.1** | -13.8% |

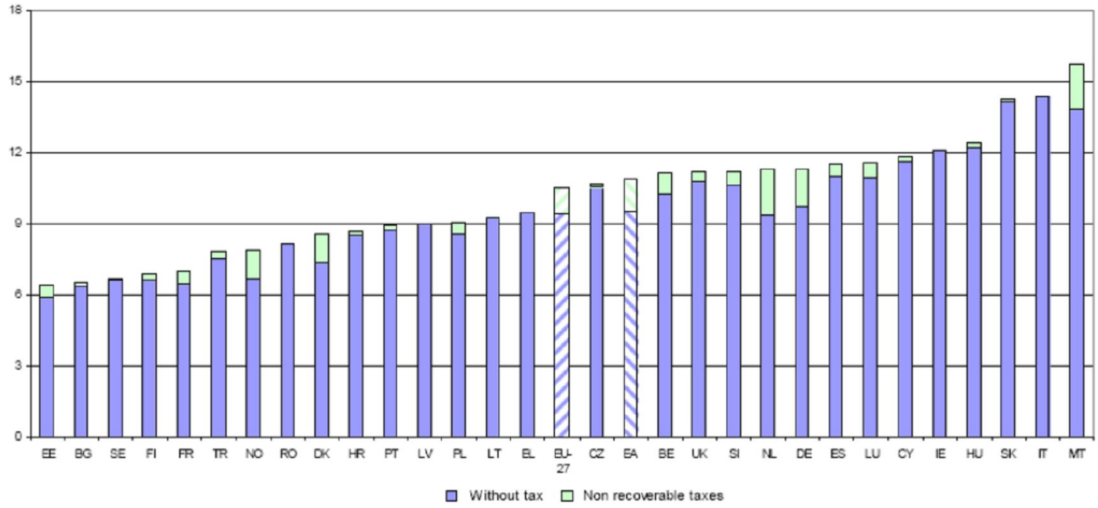
**Source: Econews.gr (2010)**

We also present data related to the evolution of prices in various countries including Greece, in order to acquire a broader perspective over Greek tariffs. Figure 7-1 illustrates price fluctuation through the years for Greece and other Mediterranean countries, Figures 6-1 and 6-2 show electricity prices for European countries for the first semester of 2009. The fact that Greek prices are relatively low compared with other European countries is explained by the fuel mix in Greece and the fact that low-price lignite is mostly used to serve the base load.




**Source: European Commission (2010)**

**Figure 6-1: Electricity prices for household consumers (2009 s01) in €/kWh**




**Source: European Commission (2010)**

Figure 6-2: Electricity prices for industrial consumers (2009 s01)

# Part 2: Limitations of the Greek wholesale market and Steps toward a healthier market structure

# 7 Limitations of the Greek wholesale market

The progress of the liberalized electricity market in Greece has been slow. According to the European Parliament (Altman *et al.*, 2010), Greece is classified among the laggards of electricity market liberalization. This assessment has been mainly based on Greece not fulfilling the provisions of the 2nd energy package. Governmental policies have been influenced by electricity market interest groups; instead of establishing a sound legal basis for healthy competition, initial legislation offloaded difficult policy issues onto future legislative measures. Consequently, the market has been susceptible to manipulations of various kinds, to the detriment of new entries and of efficiency upgrades.

The present Chapter describes significant limitations of the Greek wholesale electricity market that have prevented its advancement. A distinction needs to be pointed out here. Firstly, there are limitations, which are intrinsic to the nature of electricity markets and are not encountered in other non-electricity markets. Secondly, there are limitations that are typical of the Greek market, and cause additional distortions to the market operation.

Several key issues that concern market efficiency have been put under scrutiny during public consultations conducted by RAE (see RAE, 2010b). Topics discussed in this context are embodied in the current Chapter together with other market limitations that have been strongly argued by market entities.

## *7.1. Limitations intrinsic to the Electricity market*

The electricity markets present special intrinsic characteristics that are not present in other markets and largely determine the feasibility and efficiency of the market mechanisms.

A primary functional determinant is the inelasticity of the demand. From the consumers' side, in practice there are no substitutes for electricity; furthermore, customers are unable to adjust significantly their electricity consumption at present. This is primarily because the infrastructure of the transmission system does not support demand response, in general. Another related impediment for demand response is the consumers' inherent inability to be aware of the evolution of prices in real time, and, thus, respond accordingly. In order to address these issues, some countries are making inroads to grids and meters allowing the adjustment of consumption according to the electricity price fluctuation, known as smart grids and smart meters, respectively.

From the System Operator's side, although there is legally the obligation to proceed to small adjustments of the electricity flow when necessary, distortions in supplied electricity imply degradation of the electricity as a product, while there are excessive costs in interrupting the electricity supply for financial or other reasons, such as public health, national security, etc. Thus, demand inelasticity places significant burden also on the System Operator in its attempt to cover the demand and balance the market at all times.

Another critical factor is the variation of the demand; demand levels vary within quite a broad spectrum. The demand curve is heavily affected by weather conditions, especially during the summer periods, wherein demand levels hit their yearly peak. Concerning the trend of average demand, it is ascending in the course of the years (Table 7-1), as is the common case in electricity markets internationally. These characteristics (trend and fluctuation), call for considerable power reserve margins so that demand is always satisfied.

**Table 7-1: Forecast of Peak/ Annual Electricity Demand of the Greek Interconnected System 2006-2011**

| Year | Low Scenario | | Basic Scenario | | High Scenario | |
|---|---|---|---|---|---|---|
| | Peak load (MW) | Demand (MWh) | Peak load (MW) | Demand (MWh) | Peak load (MW) | Demand (MWh) |
| 2005 | 9,800 | 52,500 | 9,800 | 52,500 | 9,800 | 52,500 |
| 2006 | 9,936 | 54,057 | 10,126 | 54,586 | 10,397 | 55,112 |
| 2007 | 10,301 | 55,679 | 10,501 | 56,496 | 10,786 | 57,316 |
| 2008 | 10,672 | 57,439 | 10,882 | 58,473 | 11,183 | 59,609 |
| 2009 | 11,048 | 59,070 | 11,270 | 60,519 | 11,586 | 61,993 |
| 2010 | 11,431 | 60,842 | 11,664 | 62,636 | 11,997 | 64,473 |
| 2011 | 11,820 | 62,667 | 12,066 | 64,828 | 12,416 | 67,052 |
| Growth 2005/2011 | 21% | 19% | 23% | 23% | 27% | 28% |

**Source: IEA (2006)**

A final significant issue concerning the development of the electricity market is the intricacies of adding new units. These are capital intensive investments, requiring several years for licensing and installation, while the government strives to acquire a fuel mix helping it reach the 20-20-20 target. For the Greek system, the increasing demand necessitates capacity additions. Even though recent legislation has tried to facilitate investors, Greece is still far from reaching a successful outcome. In order to achieve incentivizing the market to deliver installation of satisfactory size and type, the country has to establish an effective incentive scheme.

## *7.2. Limitations of the Greek electricity market model*

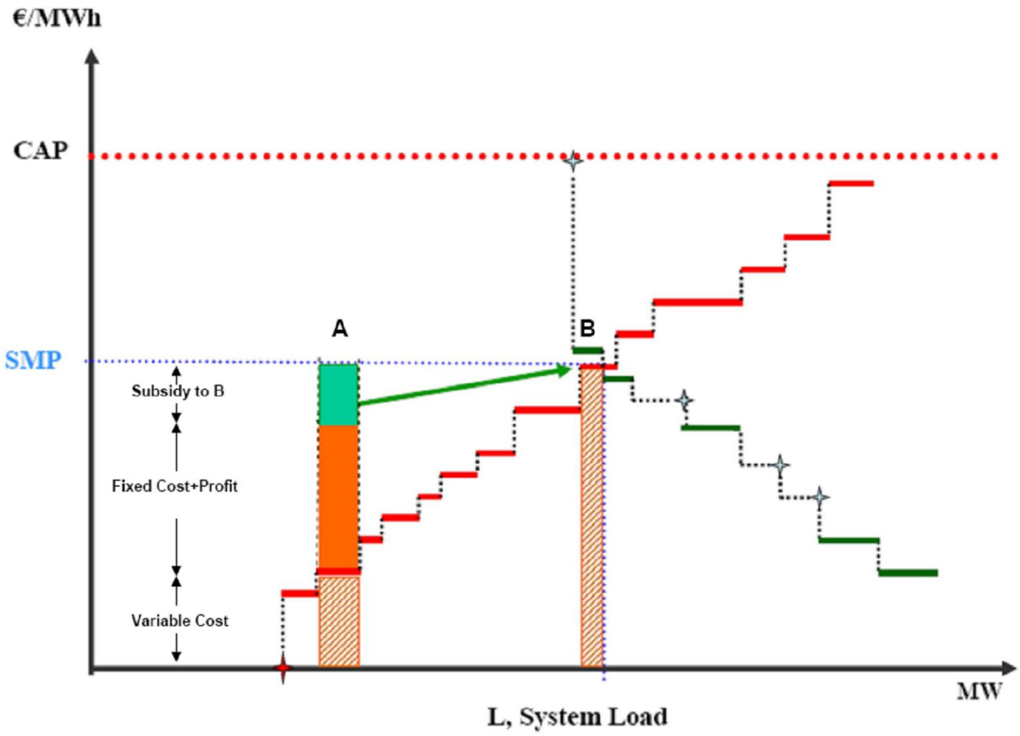
### 7.2.1. Market power

The concentration level of the market players and their corresponding power are critical points for the success of a liberalized electricity market. It is common knowledge that the higher the market concentration in a deregulated market is, the more extensive market abuse may become. Citing the case of liberalization pioneers England and Wales, the existence of a small number of large companies at the early stages of liberalization led to significant dysfunctions; the recognition of these limitations by both the government and the market participants led to structural changes on the market set-up.

The Greek electricity market is highly concentrated, since the incumbent holds the vast majority of installed capacity. As mentioned already, its units are of a diverse fuel mix, including lignite units that serve the base load, hydro units, natural gas units, etc. The other generators operate units of significantly less capacity and of a single fuel (natural gas) as a rule. This contrast gives unduly advantages to the incumbent, which extend to the pricing process.

The Greek market system applies uniform pricing. Therefore, all generators selected to produce energy are paid by the System Marginal Price (SMP), i.e. the highest bid price among all successful bids in the day-ahead market. The price bids of units are driven by two counter-acting forces: i) they should be high in order to cover their variable costs, and even cover their fixed costs; ii) they should be low to ensure their selection. Note that as a rule, the units with high variable costs are the ones placing high bids with a view to cover their high variable costs along with their high fixed costs, as opposed to the low-cost thermal units. Taking into account that the Grid Control and Power Exchange Code sets as minimum bid price the minimum variable cost of units, the high-cost units face difficulties in offsetting their fixed costs.

Figure 7-1illustrates cross-subsidization, a characteristic way in which the incumbent, possessing generating units of various types, is favored by the pricing system. In this Figure unit A has lower variable cost and unit B has high variable cost, and, at the same time, its bid defines the SMP. Both units are paid the bid price of unit B. Assuming that the bid of unit B reflects its variable cost only, this unit is unable to profit or recover any fixed costs. At the same time, unit A recovers all variable and fixed costs, and also achieves a profit. If these two units belong to the same company, unit A's profit may be used to subsidize unit B and, thus, compensate both its variable and fixed costs.




**Source: Lekatsas (2009)**

**Figure 7-1: Cross-subsidization between units of the same generator**

Thus, a company that owns units of various fuel types has the advantage of subsidizing its high-variable-cost units with the profits made by its low-variable-cost units. This is not possible for generators with one or more units of the same type. This disparity provides grounds for other means of power abuse, such as withholding of units in order to strategically raise prices, especially in times of short supply. A typical example demonstrating the catastrophic implications of these strategies is the California market meltdown in 2000 and 2001, which is used as a standard case study in the literature.

Experience and research concur in that an ideally competitive market consists of many players operating with medium market power at most. This market scheme prevents price distortions, while all participants are competing on an equal basis. As long as Greece's incumbent is largely advantaged by much greater capacity and choice of unit types, the market terms are far away from the ideal competitive situation.

Useful techniques have been developed to assess the liberalization level of a market based on its concentration level. A commonly acceptable metric is the Herfindahl-Hirschman Index (HHI) which measures the concentration level of a market. The HHI calculation is based on the relative size of the firms participating in the market. The index is equal to the sum of the squares of the market shares of the companies in the industry multiplied by 10,000. Next, a few examples depict the insight the HHI is providing in assessing the market concentration status.

- For a highly fragmented case of a market comprising 50 equivalent firms, possessing 2% market share each, the HHI is:

$$HHI1 = (50*0.02^2) * 10,000 = 200$$

- If there are 5 participants possessing a market share of 20% each, the HHI is:

$$HHI2 = (5*0.2^2) * 10,000 = 2,000$$

- For a market in which one participant holds 60% of the market, while 4 other firms hold 10% each, the HHI is:

$$HHI3 = (0.6^2 + 4*0.1^2) * 10,000 = 4,000$$

- Lastly, in the extreme case of a firm holding the 100% of a market, the index is:

$$HHI4 = 1^2 * 10,000 = 10,000$$

Thus, a high value of the HHI shows a small number of market participants holding large market shares, reaching 10,000 in the case of a total monopoly.

The HHI can be calculated for electricity generators in terms of capacity, produced energy or other. Its rating value is translated as follows:

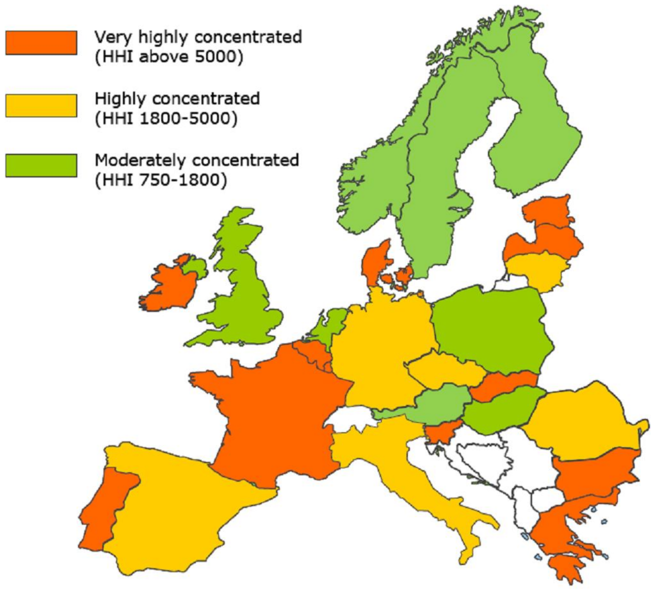
- HHI = 10,000 → The market is a total monopoly
- 5,000 < HHI < 10,000 → The market is highly concentrated
- 1,800 < HHI < 5,000 → The market is moderately concentrated
- 1,000 < HHI ≤ 1,800 → The market is sufficiently competitive
- HHI ≤ 1,000 → The market is highly competitive.

Table 7-2 and Figure 7-2 present the HHI indices for generation capacity in EU member states. One may observe that the Greek market is excessively concentrated. In terms of produced energy (and not capacity), the HHI is also very high. According to Lekatsas (2009), for the year 2007 the HHI equals to 8,301.43, corresponding to a highly concentrated market. To lessen the HHI, Greece should obviously reduce the scope of the monopoly.

**Table 7-2: Wholesale market position in electricity 2007/2008**

| | Number of companies with more than 5% share of capacity (%) | | | Share of 3 biggest companies (by capacity) (%) | | | HHI (by capacity) | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | Δ | 2007 | 2008 | Δ | 2007 | 2008 | Δ |
| **Belgium** | 2 | 2 | 0 | 99.9 | 97.5 | -2.4 | 8390 | 7206 | -1184 |
| **France** | 1 | 1 | 0 | 93 | 93 | 0 | 6960 | NA | |
| **Germany** | 4 | 4 | 0 | 85.4 | 84.7 | -0.7 | NA | 2008 | |
| **Gr. Britain** | 8 | 8 | 0 | 41 | 42 | 1 | 986 | 901 | -85 |
| **Greece** | 1 | 1 | 0 | NA | NA | | 10000 | 10000 | 0 |
| **Hungary** | 5 | 5 | 0 | 67 | 67.9 | 0.9 | 2119 | 1911 | -208 |
| **Italy** | 5 | 5 | 0 | 61.2 | 57.6 | -3.6 | 2126 | 1351 | -775 |
| **Latvia** | 1 | 1 | 0 | 93 | 94 | 1 | 8110 | 8110 | 0 |
| **Lithuania** | 3 | 3 | 0 | 84 | 85 | 1 | 3160 | 3095 | -65 |
| **Luxembourg** | 3 | 3 | 0 | 80 | 79 | -1 | 5843 | 5682 | -161 |
| **Portugal** | 2 | 2 | 0 | 72.5 | 72.2 | -0.3 | 4472 | 4521 | 49 |
| **Romania** | 5 | 5 | 0 | 63.7 | 70.98 | 7.28 | 1813 | 2116 | 303 |
| **Spain** | 5 | 5 | 0 | 76 | 72.9 | -3.1 | 1827 | 1716 | -111 |
| **Netherlands** | 6 | 4 | -2 | 61 | 69.9 | 8.9 | 1592 | 1551 | -41 |

**Source: European Commission (2010)**




**Source: Altman et al (2010)**

**Figure 7-2: Degree of concentration in electricity wholesale markets**

### 7.2.2 Unbundling

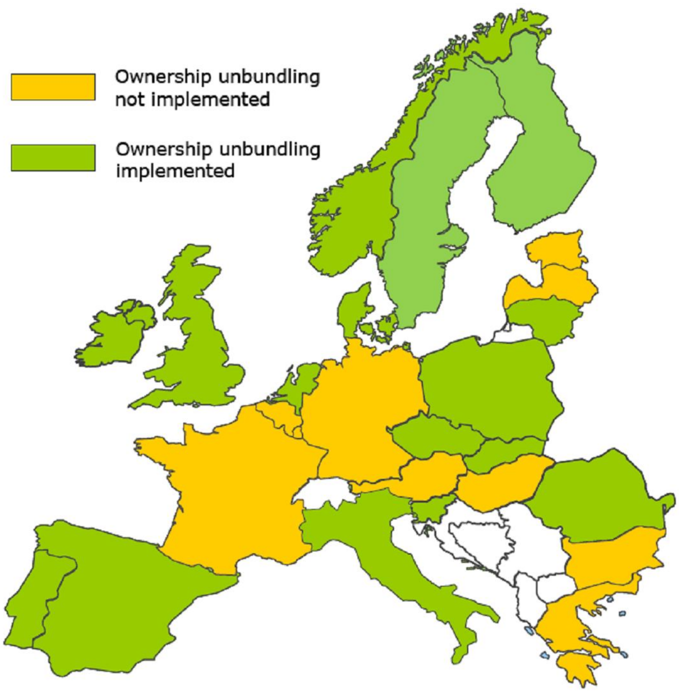
A properly operating competitive market needs to provide equal terms and opportunities to all participants. Practically these requirements necessitate vertical separation of arms that are potentially competitive (e.g. generation and retail supply) from arms that are naturally monopolies, i.e. distribution, transmission, system operation (Joskow, 2008).

In Greece, the unbundling process has evolved in a very slow pace. The Transmission System Operator has been established as a majorly state-owned company with PPC holding the remaining 49% of shares. This original scheme was supposed to be temporary, with a view to distribute shares of PPC to the new market participants. Nevertheless, until today the original scheme is still in place, causing severe concerns about the required impartiality of TSO. Completing the dominance picture, to-date PPC continues to be the Distribution System Operator, contrary to the unbundling prerequisites of the competitive market framework, and despite the recent decision of PPC's board about creating a separate TSO for distribution.

Moreover, the electricity networks are the property of the incumbent. Thus, it remains the exclusive owner of the transmission and distribution networks and is solely responsible for their expansion and maintenance following HTSO's mandates.

The functional unbundling of networks would be a decisive move towards healthy competition in the electricity market. In a broader view, EC commissioners carry the unbundling procedure one step further, asking for the physical (and not merely the functional) unbundling of the generation divisions from transmission and retailing as necessary. To justify this request, they cite competition deficiencies in Germany and France, where major players controlling network assets managed to inhibit new entry and to thwart the access of other generators to consumers (Sioshansi, 2008).

The unbundling progress of a country has been shown to be a critical factor in assessing the advancement of a liberalized market. It is also useful to evaluate the situation of the Greek electricity market compared to other electricity markets. Figure 7-3 illustrates the progress of unbundling of Transmission System Operators (TSOs) in different member states, Table 7-3 presents quantitative data for TSO unbundling in EU member states, whereas Table 7-4 presents data on the Distribution System Operators (DSOs) in various European countries, in order to lend a wider perspective over the unbundling developments and appreciate the comparatively slow progress of Greece.




**Source: Altman et al (2010)**

**Figure 7-3: The state of full ownership unbundling of TSOs in electricity**

**Table 7-3: Unbundling of electricity transmission operators**

| | Number of TSOs | Number of TSOs Ownership Unbundled | Public Ownership | TSO network Assets With | Without |
|---|---|---|---|---|---|
| **Austria** | 3 | 0 | 75.5 | 1 | 2 |
| **Bulgaria** | 1 | 0 | 100 | 0 | 0 |
| **Cyprus** | 1 | 0 | 100 | 0 | 1 |
| **Denmark** | 1 | 1 | 100 | 1 | 0 |
| **Finland** | 1 | 1 | 12 | 1 | 0 |
| **France** | 1 | 0 | 84,66 | 1 | 0 |
| **Germany** | 4 | 0 | 0 | 4 | 0 |
| **Great Britain** | 1 | 1 | 0 | 1 | 0 |
| **Greece** | 1 | 0 | 51 | 0 | 1 |
| **Hungary** | 1 | 0 | 0.01 | 1 | 0 |
| **Ireland** | 1 | 1 | 100 | 0 | 1 |
| **Italy** | 8 | 1 | 30 | 8 | 0 |
| **Luxembourg** | 1 | 0 | 32.8 | 0 | 1 |
| **Northern Ireland** | 1 | 1 | 0 | 0 | 1 |
| **Norway** | 1 | 1 | 100 | 1 | 0 |
| **Poland** | 1 | 1 | 100 | 1 | 0 |
| **Portugal** | 3 | 1 | 51 | 1 | 0 |
| **Romania** | 1 | 1 | 76.5 | 1 | 0 |
| **Spain** | 1 | 1 | 20 | 1 | 0 |
| **Sweden** | 1 | 1 | 100 | 1 | 0 |
| **The Netherlands** | 1 | 1 | 100 | 1 | 0 |

**Source: European Commission (2010)**

**Table 7-4: Unbundling of electricity distribution operators**

| | Total number of DSOs | Number of DSOs legally unbundled | Number of DSOs with less than 100,000 customers |
|---|---|---|---|
| **Germany** | 855 | 150 | 779 |
| **Spain** | 329 | 329 | 323 |
| **Sweden** | 175 | 175 | 158 |
| **Italy** | 163 | N/A | 152 |
| **Norway** | 159 | 55 | 152 |
| **France** | 148 | 0 | 143 |
| **Austria** | 130 | 11 | 119 |
| **Denmark** | 101 | 101 | 96 |

| | Total number of DSOs | Number of DSOs legally unbundled | Number of DSOs with less than 100,000 customers |
|---|---|---|---|
| **Finland** | 89 | 50 | 83 |
| **United Kingdom** | 18 | 18 | 4 |
| **Portugal** | 13 | 11 | 10 |
| **Luxembourg** | 9 | 2 | 8 |
| **The Netherlands** | 8 | 8 | 5 |
| **Bulgaria** | 4 | 4 | 1 |
| **Greece** | 1 | 0 | 0 |
| **Ireland** | 1 | 0 | 0 |
| **Cyprus** | 1 | 0 | 0 |

**Source: European Commission (2010)**

### 7.2.3 The pricing system

The pricing process of the Greek electricity market exhibits several weaknesses that affect either directly or indirectly the progress of liberalization. It is critical to deal with these issues, since they deter new entries, as well as investments in upgrading the fuel mix, while they elevate the risks faced by participants.

Non-priced offers

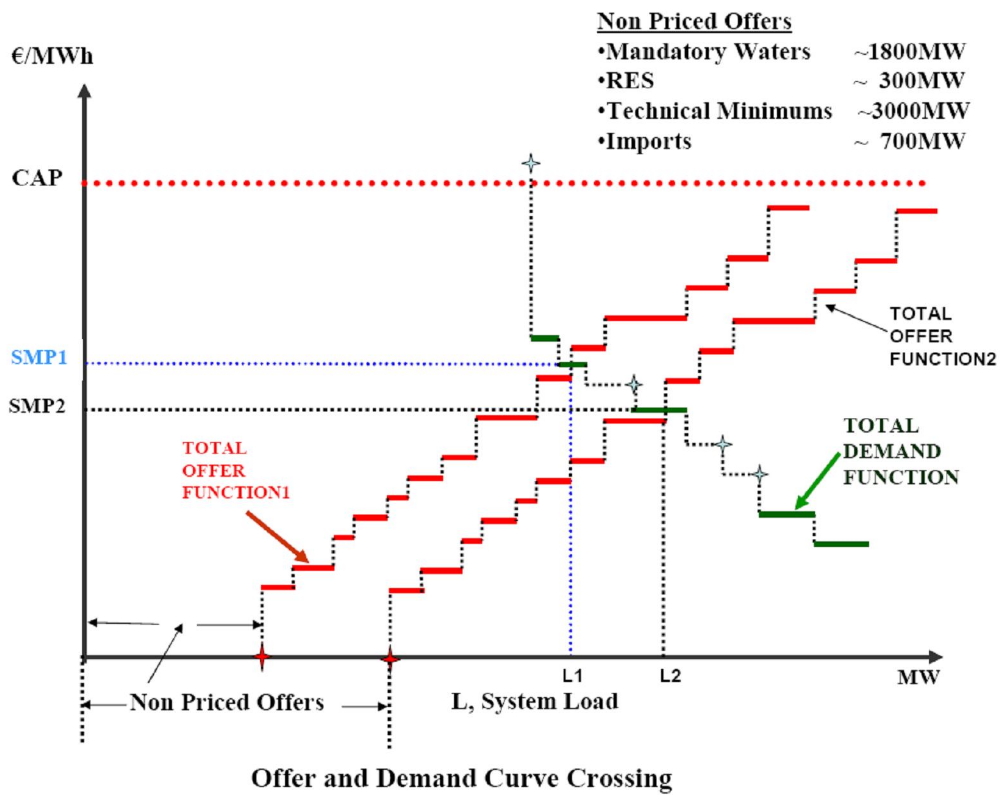
A key factor affecting market prices is the so called "non-priced" offers. These are offers that are outside the bidding process of the day-ahead market; instead they have priority over all offers. Thus, in the computation of SMP they are considered to be of zero prices. It appears that market participants make use of these offers in order to manipulate the price formation process. The offers belonging to this category are the following:

- The offers of Renewable Energy Sources (RES) – There are practical reasons for accepting immediately these offers, since currently there is no economically efficient means of storing RES production, and, thus, it should be consumed instantly. There is also a significant political reason for this decision, due to the fact that the Greek Government is under intense pressure to boost "clean" energy and meet the agreed environmental targets.

- The Technical Minimums of units – These are the minimum power levels whereby units need to function to guarantee their operational stability. Technical minimums are a critical factor particularly for the operation of large coal-fired units. These units require significant time and high costs to be put into and out of operation; consequently, they are not flexible enough to follow the demand profile. On this basis, though not the optimum economical solution, these units are scheduled to operate at their Technical Minimum during night hours, which are periods of low demand. An immediate issue that follows from this practice has as follows: Lekatsas (2009), among others, has presented, that the night hours of operation at the Technical Minimum, coincide with the periods of low demand in Italy. The acceptance of the Technical Minimum offers raises SMP to a point that the system has to proceed to undue imports from Italy. In addition, this practice clashes with fair competition standards, since units of different (more flexible) technology do not get similar favorable treatment.
- Energy imports – There are long-term schedules regarding energy imports, based on auctions of transmission rights for the interconnections. In order to deliver these schedules, the SO sets a zero price to the imported energy. Despite the practicality of this measure, it threatens the efficiency of the market's operation due to the disparity between the market clearing price and the import price. This disparity came to prominence in periods of prolonged scarcity, like the summer of 2007, when the system was in great need of imports. During such periods importers provided energy for which they paid prices higher than the statutory upper limit of prices in the Greek market, known as cap price (set at 150 €/MWh). Since imports are scheduled as non-priced offers, i.e. at zero price, the excessive import prices did not affect price formation. As a result, these importers faced significant damages, which were not translated to appropriate price signals for the participants in the wholesale and retail markets to adjust accordingly.
- The Mandatory Injection of Hydro Units (commonly known as Mandatory Waters) – These offers refer to the production of hydro units when supplying

water for irrigation or flood prevention. In several public consultations, market participants have expressed concerns about the lack of transparency in the management of water resources (RAE, 2010b). Considering the total hydro energy generated and the historical data of hydro energy injections, they have specifically pointed out cases of excessive amounts of hydro energy been generated as mandatory. In addition, they have indicated a systematic increase of Mandatory Injections in periods of high SMP, which points to a strategy to hold prices low, and thus forcing some high-cost units of independent generators out of schedule; this practice is further explained below and constitutes evidence of consistent price manipulation, a typical case of market abuse.

Figure 7-3 depicts the strong influence that mandatory hydro injections may exert on the market clearing price. The related example was originally presented by Lekatsas (2009), and describes a day when acclaimed non-priced offers reached approximately 50% of the capacity participating in the electricity market. The diagram uses a hypothetical hour "1" with load L1 and its following hour "2" with load L2, assuming that mandatory injections are higher in the second hour and L2 > L1. The green line tagged "total demand function" represents the demand bids in the day-ahead market. The red lines tagged "total offer function1" and "total offer function2" depict the energy offers for hours 1 and 2 respectively. The intersection of these two curves with the total demand function consists the respective System Marginal Prices (SMPs). As can be seen, SMP2 is lower than SMP1, therefore the injection of more mandatory hydro power drives electricity prices down. The ability to insert more hydro power as mandatory in the non-priced offers has become a common practice to hold the SMP low. This possibility of price manipulation by hydro managers renders the system amenable to market power abuse.




**Source: Lekatsas (2009)**

**Figure 7-4: The impact of mandatory hydro injections in the SMP calculation**

Export policy

The export policy has also received severe criticism. During some periods of scarcity of resources, the System Operator proceeded to restrict exports in order to maintain system security. However, in terms of a liberalized market, the right outlet in time of scarcity would be to increase the System Marginal Price. If this is properly done, the energy produced in Greece would be excessively costly for other countries to buy, and exports would ultimately fall (Lekatsas, 2009); at the same time, imports would be encouraged so that importers can benefit from high SMPs and the system can preserve a safe level of energy reserves.

Low limits of energy offers

Another focal point of criticism is the lower limit in prices of energy offers. The Code for Electricity defines this lower limit to be the Minimum Variable Cost of the unit submitting the offer. Market players participating in public consultations (RAE, 2010b) have raised the following concerns:

- The definition of the variable cost is not all encompassing. A practical implication of this vagueness is the fact that PPC reports only extraction cost as fuel cost for its lignite units, omitting the lignite value and external costs, such as pollution or social costs. This practice may under-report the Minimum Variable Cost, giving PPC the unfair advantage of submitting injection bids lower than its true Minimum Variable Cost.
- Having defined the Minimum Variable Cost as the lower limit allows units to place offers lower than their True Variable Cost. The independent generators expressly or tacitly suggest that PPC benefits by this measure, as it is the only company that is able to place offers quite lower than the True Variable Cost and cover subsequent losses through cross-subsidization.
- Limitations of procedures determining the Variable Cost of units. If cost elements are not validated frequently enough, generators may submit data diverging from the true cost.
- Despite indications of systematic misquotation of variable costs, there are no penalties for such strategies.

Not accounting for $CO_2$ emissions costs

The absence of accounting for $CO_2$ emissions costs into the calculation of the variable cost of units has been raised consistently by both independent generators and RAE. In addition to potential market distortions, the Greek electricity market should align with upcoming changes due to the European Union Emission Trading Scheme (EU ETS); the latter will be put into effect in 2013 for the Greek electricity market, and will assist the country to reach the 20-20-20 target. Unfortunately, hitherto there has not been any pricing or other mechanism in purely market terms promoting clean energy to complement the feed-in tariffs and the RES priority in schedules. With the costs of emissions not being priced, no price signals are offered to investors to opt for cleaner units, nor for customers to consume efficiently. In other countries, like the UK, Germany, Sweden, France, Spain, Italy and Ireland, costs of emissions have already been included in Energy Offers and contracts for supply.

Non-compliance

Non-compliance limits and charges have also been under discussion. There have been frequent references of units with low variable cost making much higher offers of energy compared to the energy they actually deliver, and declaring higher availability compared to their actual availability. This way, more expensive units were excluded unduly by the day-ahead scheduled in many cases, whereas they were called in the day to provide the energy that the low-variable-cost units were scheduled for, but failed to deliver. At this point, it should be pointed out that generators are paid for serving uncovered demand at the imbalance market clearing price, rather than the price they are bidding in the day-ahead market. As a rule, the imbalance market prices are quite lower than the offer bids of generators called to participate in the imbalance market. As a result, a) the actual marginal units are frequently kept out of the schedule, b) these units are compensated for their generation at lower prices suffering damages, c) the scheduled units are paid less, and d) the competition is infringed.

Regarding this issue, independent generators have reported the anti-competitive character of the compensation mechanism for unscheduled energy in an imbalance clearing price, instead of their price offer. The proposal is to be compensated at a price at least equal to the generator's bid price. The present remuneration method provides lower prices, and gives motives for keeping the SMP low based on a schedule of false data.

### 7.2.4 Capacity payments

In a well-functioning energy market the pricing system reflects the capacity needs of consumers. In that context, and in cases of capacity abundance, the price levels are lower; while in cases of capacity scarcity the prices rise reflecting, the market's demand for more capacity. However, international experience attests that prices do not increase fast or high enough to reflect the actual demand for power capacity.

Energy-only markets, which let producers reimburse capital costs exclusively through offer bids, have been proven insufficient to pay off the generators' capital costs. This is due to competition, which forces bid prices down until they hit the marginal costs. In this arrangement, generators lower their bids due to the pressure of competition, thus failing to compensate for their capital costs through the market. This fall-out has been more pronounced for marginal units. The gap between net revenues obtained in electricity markets and the capital cost of capacity investments has been called the "missing money" problem by Cramton and Stoft (2006).

The inability of the pricing system to provide early signs of rising capacity demand, has led investors to construct new units during periods when the lack of capacity was completely visible; the related investments most often were of the same technology. This phenomenon results in cyclical electricity prices; the latter are low when new capacity is introduced en masse in the market, and rise until the need for new capacity is again perceived as addressed. A further implication of installing a large proportion of units of the same technology, as did England in the 1990s with gas-fired units, is an excessive dependence on a certain fuel; this enhances the vulnerability of the pricing mechanisms, and introduces system security risks in relation to this fuel's price and provision.

At its first steps, the liberalized Greek electricity market followed the energy-only regime and thereafter experienced a "missing money" problem. This problem, in turn, resulted in the lack of construction of new units by market participants, despite the numerous licenses being issued. Reaching a deadlock, the market regulators adopted the proactive approach of annual capacity payments. At present, generation companies in the Greek electricity market receive a yearly remuneration for their capacity, which is currently at 35,000 €/MW for base load generators and 70,000 €/MW for peak units; however, there has been broad consensus for raising these fees.

Even though this mechanism tends to stabilize market prices, reduce investment risk and support marginal units, it presents several shortfalls regarding incentivizing the installation of new units and an efficient technology mix, which need to be addressed.

Firstly, the Greek mechanism offers a two-level uniform compensation for generators. This indiscretion casts a shadow over the effort to promote a fuel mix that best serves the needs of customers, as well as the national environmental or financial targets. It does not take into account the technology of units nor their market behavior. History has showed that incumbents tend to exploit uniform capacity pricing, choosing to resort in withholding of units in order to benefit further from the capacity payments; that was the case in the England and Wales market during the period 1991-1995 and the main reason why this mechanism has been withdrawn (Ferrari and Giulietti, 2003).

Further concerns are related to the time interval that capacity payments refer to, as they are accredited yearly to generators merely for operating during the respective year disregarding the actual performance of units during the respective year. Hence, this planning mechanism fails to accomplish its main objective of compensating units according to their participation and their contribution in sustaining reasonable electricity market prices.

Other liberalized markets have customized capacity payments with a view to render them more just and efficient. Two popular capacity remuneration schemes are: a) The capacity forward markets covering in advance the capital costs of generating units through auctions or bilateral contracts, and b) the capacity payments for generators that depend on their participation and their behavior, taking into account data like the loss of load probability (LOLP), the value of lost load (VOLL), the unit availability, and the participation time. With the liberalization of the Greek electricity market evolving, there is need for such sophisticated mechanisms to enhance capacity policy.

## *7.3 Synthesis of Greek electricity market limitations*

This final section summarizes the major limitations of the Greek electricity market described in the present chapter.

| **Limitation Category** | **Issue** | **Description** | **Effects** |
|---|---|---|---|
| Intrinsic to the electricity market | Demand inelasticity | • No substitute for electricity<br>• Infrastructure does not support consumption adjustment<br>• The TSO may adjust electricity flow, degrading electricity quality and inducing social risks | • Demand is not reduced in times of scarcity<br>• Consumers are unable to adjust their supply to keep prices low<br>• Greater need for reserves<br>• Increased difficulty for the TSO operating the system |
| | Demand variation | • Demand varies within a broad spectrum<br>• Demand varies significantly in the peak periods of consumption<br>• Demand increases during the course of the years | • Considerable power reserve margins<br>• Increasing need for new capacity of an effective fuel mix |
| | Difficulties in adding new units | • Electricity generation investments are capital intensive<br>• Lack of sufficient incentives | • Deviation from 20-20-20 target<br>• Doubtable cover of future demand |
| Greek electricity market specificities | Market power | • High market concentration<br>• The incumbent is the only producer owning units of various types<br>• Cross-subsidization of incumbents' units<br>• Price distortions | • Unduly advantages to the incumbent<br>• Ground for unfair strategies |
| | Unbundling slow progress | • The incumbent is the only generator holding shares of the Hellenic Transmission System Operator<br>• The incumbent is the owner of the networks<br>• The incumbent has been the Distribution System Operator – in October 2010 the PPC board decided the creation of an independent entity to assume this role | • Natural monopolies (networks and system operation) are not under a regime indicating healthy competition<br>• In other countries this status inhibited new entry and thwarted the access of independent generators to consumers |
| | Pricing system shortcomings | • Non-priced offers advantage to the incumbent, leave imports out of competition, and are susceptible to price manipulation | • Deterrence for new entry and efficient investments<br>• Elevated risks for participants<br>• Imports and exports |

| | | | |
|---|---|---|---|
| | | • Export policies are not reflected in the price formation<br>• Low limits of energy offers are crudely defined, favour strategic behaviour, while controls and punishments for violations are insufficient | are not determined in terms of competition |
| | $CO_2$ emissions costs omitted | • Greece has not yet complied with the EU ETS<br>• $CO_2$ emissions costs are not included into the calculation of units' variable cost | • Fuel mix efficiency is not promoted in market competition terms<br>• No incentives for investors to opt for cleaner units<br>• No incentives for customers to consume efficiently |
| | Non-compliance unaddressed | • The incumbent is accused of systematically submitting offers exceeding the production it can actually deliver<br>• Marginal units are often excluded from schedule and are afterwards called to produce in the imbalances market<br>• Behaviour of this kind is left unpunished | • Sustain of systematic behaviour<br>• Undue risks and losses for independent generators<br>• Deterrence of new entry |
| | Capacity payments | • Insufficient classification of producers into 2 categories only<br>• Insufficient consistency with the generators performance, as they simply compensate them for operating through one year<br>• Rough assessment of the capacity payment amount based on theoretical rather than technical terms | • Inefficient compensation of generators for their capital costs<br>• Failure in promoting an efficient fuel mix<br>• Cyclical trends in electricity prices<br>• Compensation is determined by regulation, instead of competition |

# 8 Proposals for a stronger market model

Based on the market fundamentals of Chapters 2-7, and the market analysis of Chapter 8, there is a clear need for reform in the Greek electricity market. Given that Greece comes under the jurisdiction of the European directives advocating a highly competitive market, the country is bound to address all limitations that hinder the market operation.

There is an ongoing discourse upon whether and how should regulation intervene in market development. The success of a thoroughly unregulated market constitutes a rebuttable presumption. According to Hogan and Pope (2007), both regulation and competition are integral pieces of a liberalized market. Regulation is responsible for developing and improving the market structure, since competition alone is unable to solve many structural problems. At the same time, regulation should complement competition in securing the market efficiency. Addressing market issues in some cases calls for market incentives, whereas in some other cases it is necessary to proceed to regulation mandates. Consequently, a successful liberalized electricity market relies on a balanced mixture of regulation and competition.

Regarding the liberalized Greek electricity market, competition has been rising slowly since its inception; in the adopted market model new entrants cover a very limited part of the demand. Notwithstanding the expressed contention for healthier competition, these entrants are powerless to drive the market toward a more competitive level. In other more successful models, company competition has shaped the scene quite actively; the entry of large firms into liberalized markets of different countries has been substantial in enhancing competition and price formation. Figures 8-1 and 8-2 illustrate humorously the competition turmoil in Europe's competitive liberalized markets.

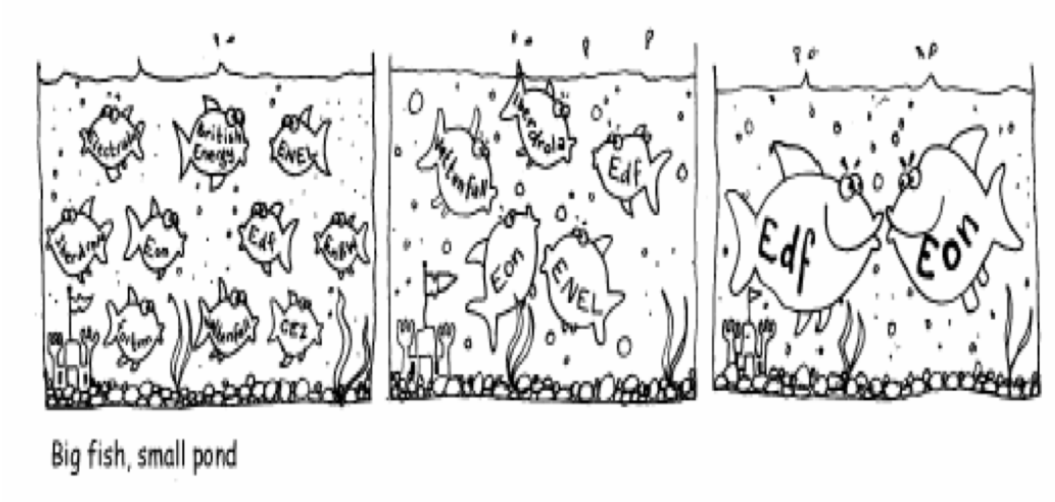



**Figure 8-1: The big winners of Europe's electricity markets liberalization**


**Source: Gary Barker Blogspot**

**Figure 8-2: French public incumbent EDF seems to control the British market**

Considering that regulation is indispensable, there is further debate on the extent to which regulation should act to address market issues. Appraising the status of the Greek electricity market, the apparent lack of incentives and the general discontent of all participants point towards the necessity of large-scale modifications in the market structure. However, drastic changes in such a critical market carry severe risk. One of the more substantial risks is related to participants currently operating or constructing generation units; the electricity industry being capital intensive features long repayment periods, and, thus, requires stability to plan expenditures. In case regulation prompts radical changes, possibly some units and large amounts of funds will be jeopardized. Furthermore, the modified market scheme would have to run for a long period in order to evaluate its success and impact; hence, investors would have to retreat from new ventures until they gain a clear perspective on the new market status.

The current chapter proposes structural modifications for the Greek wholesale electricity market that correspond to successful market paradigms in other countries. It presents policies that have been broadly acknowledged, along with some innovative approaches. It contains complementary initiatives that can be integrated to respond to the current Greek market issues.

## *8.1 The ongoing political debate on prospective changes*

The prevailing opinion among market analysts is that major problems in the Greek market are related to the large imbalance in market power. Several characteristics of the incumbent contribute to the distortion of the market: i) The dominant size, ii) the lignite units serving largely the base load and other units of multiple technologies, iii) the ownership of the electricity networks, iv) the joint participation in the TSO, v) the current jurisdiction with respect top the Distribution System Operator (DSO), and vi) the retention of the vast majority of costumers. These characteristics have triggered a brisk discussion regarding the advisable measures to diminish PPC's unfair advantages in the context of competition.

Greece is under further pressures by the International Monetary Fund (IMF) and the EU, to diminish the incumbent's power. These creditors of national debt demand full liberalization of the energy market in clear competitive terms due to the related impact in the financial sustainability of the Greek economy. They have specifically recommended i) the sale of 40% of PPC's low-variable-cost capacity (i.e. lignite and hydro units) together with the corresponding lignite mines, ii) the ownership unbundling of networks from PPC, and iii) the completion of the respective auctions until March 2011.

PPC reacted directly to the IMF/EU proposals developing a different set of measures to reinforce market competition. The company counter-proposed the sale of 40% of its energy of low-cost lignite and hydro energy production to independent producers, with the intent to lower their costs and enhancing their competitiveness. It also proposed offering shares of its units that are under construction, swap of some PPC's units with other units in different countries, as well as conducting auctions limited to independent producers for unexploited lignite deposits in Vevi, Elassona and Vegora.


**Source: Skai.gr (2008)**

**Figure 8-3: PPC's labor union protest against PPC's up an electricity pillar**

PPC's proposals provoked various reactions. RAE has concurred with PPC's proposals adding the necessity of stricter control on water resource management. At the governmental front, the Ministry of Environment, Energy & Climate Change does not accept the possibility of selling PPC units and presented the sale of energy as the last resort. However, the IMF/EU objects to this option, claiming that it does not provide a long-term solution to the market's structural inefficiency. Finally, analysts have expressed worry about the implementation of these strategies: Will the local communities react against the installation of new lignite units? If the energy sales are to be implemented, how will they be evaluated? Who will buy the energy or the lignite deposits?

It is clear that both the proposals of the IMF/EU and of PPC need to undergo a robust economic, financial, and market analysis, in order to determine the impact on the country's finances, the consumer, the market, its participants, the environment; this will form a basis of rational decisions, beyond special interests and politics. The government planned to deliver its decisions by the end of 2010.

## *8.2 Restructuring the ownership framework*

### 8.2.1 Strategies for retaining the current ownership status of the incumbent

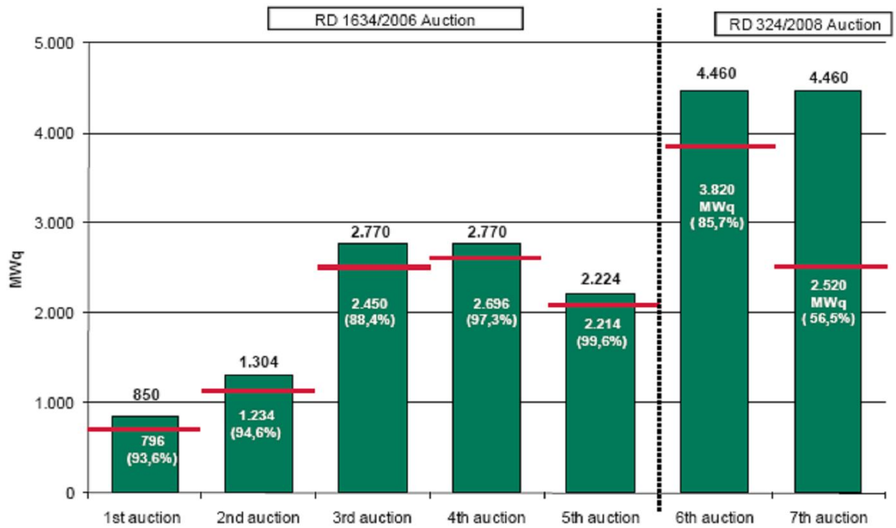
At the moment, PPC and the Greek government are trying to prevent the sale of PPC's generation assets, receiving great pressure from PPC's labour union. The option of diminishing the incumbent's market power without divesting its assets is not a groundbreaker: Policies applied internationally are offering applicable means of achieving market power harmony without extracting resources from the incumbent company.

A common example is the concept of "Virtual Power Plants" (VPPs), which has been widely implemented. This is a policy first applied by EDF in France in 2001 and was imposed by the EC as a trade-off for EDF acquiring 34.5% of EnBW, the fourth largest utility in Germany (Commission de régulation de l'énergie, 2009). VPPs are auctions of the dominants' produced energy related to certain capacity, rather than auctions of the actual capacity units. In that context, the incumbent sustains management and control of the concerned plants, while its market power reduces. VPPs are offered under two different contract types: For base-load and for peak-load. Approximately 80% of the electricity capacity traded is for base-load. With regards to the duration of the related contracts, there are several variations: For 3, 6, 24, and 36 months.

The VPP policy has been also introduced in Belgium for the dominant Electrabel, in Netherlands for Nuon, in Denmark for Elsam, in Spain for Endesa and

Iberdrola with combined auctions, in Portugal for REN and EDP, in Germany for E.ON and RWE with separate voluntary auctions, and with some variations in USA with the Texas Capacity Auctions (Ausubel and Cramton, 2009). Figure 8-4 shows the 7 VPP auctions held in the Spanish electricity market – the total amount per auction is written above the respective bar in MWq (quarterly equivalent for MW, i.e. energy that corresponds to the capacity output for three months); the total amount purchased is written inside the bar along with the corresponding percentage, and the red line shows the level of purchased amount.

Noting the popularity of the VPP policy among this large group of countries under various market models, it seems that this proposal is worth serious consideration for the Greek market.




**Source: CNE (2009)**

**Figure 8-4: VPP auctions in the Spanish electricity market**

Another case of power mitigation without involving divestiture is the policy of Directed Contracts (DCs), which has been developed in Ireland. The Irish electricity market is organized as a mandatory pool with high concentration, equivalent to the Greek electricity market. DCs are Contracts for Differences (CfDs) that the Irish regulatory agencies require of incumbents to sign with suppliers. The regulatory entities define the methodology, pricing and quantity of these contracts every year. There are three types of DCs: base-load, mid-merit and peaking. The related quantities are calculated based on the HHI target of a 1,150. The following are significant components of the DC mechanism:

- The HHI is examined quarterly for each type of DC
- The DC price is determined through the projected SMP in the pool considering scenarios of fuel costs and $CO_2$ emissions
- The eligibility of a supplier wishing to participate in a DC is estimated with reference to the supplier's share in each customer category, the consumption profile of each category, and the total annual consumption of each customer category, all quantities referring to the previous year (CER&Utility Regulator, 2010).

The DC mechanism was created in order to limit the generation that dominants inject into the day-ahead market and receive spot-based prices for. Generators receive the SMP only for a part of their produced energy, while the rest is bound by the DCs and is compensated with the difference between the DC price and the SMP. Since the respective generators lose money on the CfDs as the SMP rises, DCs deter incumbents from placing excessive offer bids. Consequently, DCs help preserve SMP prices below unduly high levels. The DC option could be fairly attractive for the Greek market and should be examined thoroughly, considering also the distinct similarities between the Greek and Irish markets.

Concluding, to support the preservation of the current ownership scheme, there are some options, including the VPPs and DCs discussed above. These options have been tested in different countries and are broadly acceptable. Their implementation is based on indices reflecting the market status and, thus, it is adjustable to varying market conditions, while offering a healthier competition. Nevertheless, given the unique situation of the Greek electricity market (considerably stronger advantages for the incumbent, who owns the networks and nearly 50% of the TSO), as well as the low share of independent producers in the market, it is questionable whether the market power issue may be addressed without modifying the ownership scheme of the dominant company.

### 8.2.2 Establishing an efficient ownership regime

There are distinct advantages related to preserving a large generation entity like the incumbent in the electricity market.

Firstly, a large company serving the majority of customers and possessing a wide variety of human and technical resources contributes to system robustness, since the coordination of the company's units is more reliable, as opposed to the coordination of units belonging to different producers; the latter relies on efficient information flow and technical management by the SO and numerous generators. Furthermore, the large size of the company offers increased immunity to market fluctuations and different risks, in contrast to small participants; this feature is far more important in times of recession (such as the current one), especially since Greece is in need of high investments on new "clean" units.

Secondly, the devolution of an incumbent company involves significant social issues: The incumbent offered pricier tariffs for industrial and commercial consumers to the advantage of domestic ones, while maintaining Public Service Obligations for vulnerable customers. In the liberalized market, new participants protest against PSOs, while tariffs change to reflect the actual consumption of each consumer removing any cross-subsidizations between different consumer categories. These issues raise reasonable doubts regarding the social side of healthier competition, and evoke discussions about future energy poverty.

For the moment, the focus of the electricity community is on the privatization of PPC's "cheap" capacity; nevertheless a plain transfer of PPC's assets to independent producers is not the sole solution. Public ownership may be applied in alternative ways and still benefit the market. Other countries display a long tradition in different ownership models, in which consumers and municipalities own electricity assets, and have adjusted the ownership model to best serve the needs of consumers. Haney and Pollitt (2010) analyze interesting paradigms of public ownership in combination with other firms or individuals - notable examples include the following:

- The case of wind energy development in Denmark: The first wind turbines were installed in the 1970s by an appreciable number of individual consumers without government support whatsoever. The government established an energy policy to promote wind energy during the 1980s, providing special incentives to private owners. Thereafter consumers were organized to communities implementing larger investments either alone or in collaboration with municipal energy companies. These arrangements have resulted in wind energy covering today an impressive 20% of Denmark's total production. (See also Figure 8-5.)

- New Zealand has established distribution assets owned by consumer trusts and local authorities
- In Northern Ireland there are transmission assets under mutual ownership of consumers
- In Finland industrial consumers teamed up with publicly owned utilities for the construction of a nuclear unit.

Thus, two interesting points for consideration are a) the demand-side activation, and b) the sophisticated collaborative schemes of utilities, independent generators, domestic and industrial consumers. Of course, one may argue that Greece does not have the tradition, the culture, or the experience to proceed in such schemes. Notwithstanding, these and other schemes provide an insight on the impact that individual investments may have on energy development, and they constitute valuable alternatives for perspective ownership arrangements involving the state.

**Source: U.S. Department of the Interior (2009)**

**Figure 8-5: The Middelgrunden wind farm in Denmark – joint ownership by a local municipal utility and a local cooperative**

In order to develop the Greek model, one should also take into consideration issues that have emerged in highly advanced electricity markets. A characteristic example concerns the market in England and Wales and regards the split of the original incumbent company. At the launch of their liberalized market, the incumbent company was divided into two companies owning the fossil-fuelled power stations, one company owning the nuclear power stations, and a firm owning the national grid; however, the initial steps of the liberalized market were unsatisfactory, as the three aforementioned companies retained significant leverage at the expense of competition. This example indicates that in order to achieve the mitigation of market power in the presence of large incumbents, regulators should assess thoroughly potential future developments. Intervening into such important areas may rekindle original problems, the resolution of which may require additional interventions. Continuous waves of reforms may induce instability and insecurity in market participants, undermining the initial target of establishing a reliable market structure.

In conclusion, limiting the market power of PPC does not necessarily mean mere divesting of assets. There is a high possibility that market power problems will persist, whereas the risk to social policy will probably be a political mistake. However, promoting markets does not entail losing sight of public interests. The international realm offers viable solutions where the notion of public ownership may be transformed to innovative ownership schemes combining state-owned (or municipality-owned) companies with consumers for small or large scale investments. An interesting solution for market power mitigation in the Greek electricity market appears to be the division of PPC into a limited number of separate companies of unique technology type, with the simultaneous entry of new shareholders. This would require an adequate incentive scheme encouraging the introduction of consumers in generation-side investments.

As for the unbundling of network assets and the exclusive participation of PPC in the TSO, these assets and the TSO should all come under state-only ownership, ensuring equal access for all participants and central maintenance and investment planning of networks.

## *8.3 Introducing bilateral markets*

The Greek spot electricity market, along with spot electricity markets elsewhere, has been proven inadequate to fulfill the expectations of deregulation, i.e. underpin healthy competition, lower electricity prices and guarantee the system security. The most apparent deficiencies of spot markets include a) vulnerability to fuel price volatility, and b) amenability to market power abuse. Hence, countries that entered liberalization with a mandatory pool system moved on to adopt a semi-compulsory pool combined with out-of-the-pool bilateral contracts. Typical examples are: a) the England & Wales liberalized market, which kicked off as a mandatory pool failing to lower prices, and b) the California electricity market, another mandatory pool, which collapsed during an extended tight power period. The risks that have been painfully experienced in the mandatory pool created a need for financial hedging (Ferrari and Giulietti, 2003).

Bilateral contracting disengages participants from the SMP and allows them to form prices according to their own estimations. A bilateral contract is an agreement in which a generator agrees to deliver specified amounts of energy to a supplier or a consumer at a specified price. The System Operator first schedules the energy production bound by bilateral contracts and then adds the generators competing in the pool to cover the rest of the demand. Consequently, consumers can choose between buying energy through the pool at the SMP or forming a bilateral contract with a generator at a price they consider worthy; that is, in case consumers perceive distortions in the SMP formation, they can turn to bilateral contracts. This price formation context helps the system deter market power abuse, and, thus, prices are due to evolve free from distortions.

There is great importance in curing the pricing process, as efficient long-term pricing sustains significantly the stability of the electricity market (Termini and Cavallo, 2007). Market stability comes from the greater reliance on the market, and the encouragement of future investments when participants can count on long-term efficiency of price formation; this is the major contribution of bilateral contracts. However, along with the precious market stability, bilateral contracts carry important drawbacks. An obvious flaw is the lack of transparency in the formation of these contracts, in contrast to the transparency of the mandatory pool. Next, bilateral contracts reduce scheduling flexibility – schedulers are obliged to abide by these contracts committing specific units, thus they are under extra constraints in selecting units or adjusting schedules when necessary. As a result, there is a critical trade-off between liquidity and stability when adopting bilateral contracts.

In the Greek market context, bilateral contracts offer the chance to change radically the current market model and provide a more orthodox competition set-up. In the present section two innovative approaches are analyzed: The forward bilateral contracts and the demand-response contracts.

### 8.2.1 The forward market

There is a majority view among analysts internationally concerning the structure of the energy market. The common belief is that the optimal set-up consists of a spot market trading energy for immediate consumption like Greece's day-ahead market, a medium-term forward market and at least one long-term forward market. Medium-term markets refer to forward contracting of energy 1-3 years in advance of delivery time, whereas long-term markets refer to contracting energy to be delivered in more than 3 years after the agreement.

A highly desirable advantage of forward contracts is their salutary effect upon market power abuse. On the generation side, participants are discouraged from raising (unduly) spot prices, since forward prices are connected to spot prices and thus such raises would incur damages through forward contracts. This concept is the basis of the Irish Directed Contracts mentioned above. Furthermore, when giving consumers the choice between spot prices and bilateral contracting, they will prefer bilateral contracts to seeking energy through the pool when the SMP is susceptible to strategic behavior; hence, the price elasticity of the demand participating in the spot market deters market power abuse.

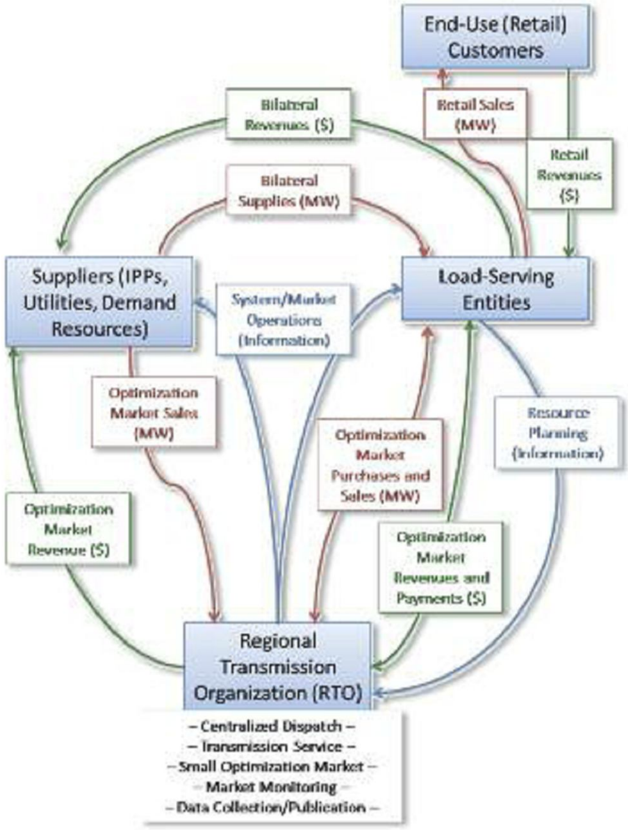
Another significant feature of futures trading is that they have shown to increase the quantity of bilateral contracts, thus favoring effective consumer choice (Termini and Cavallo, 2007). Expansion of bilateral contracting combined with the stabilizing impact of forward markets ultimately lead to more stable and reasonable price rates.

Finally, a substantial contribution of forward contracting is that it enhances the market's compatibility with longer-range system planning for generation, transmission and demand response investments (APPA, 2009). These infrastructure investments are critical from many different aspects – they involve significant financing, political decisions and technical considerations regarding future planning. Spot markets fluctuate upon transient market effects; therefore they are insufficient or even misleading in determining future decisions of important magnitude. Forward markets resolve this fundamental limitation, as they indicate long term future expectations of hourly market prices and eventually provide the appropriate signals for large-scale infrastructure investments.

Regarding the time span of forward contracts, APPA (2009) places great emphasis in long-term bilateral contracts (e.g. of 10 years). The US experience in bilateral contracting has indicated that medium-term contracts tend to be more expensive than spot markets, since they embody costs for ancillary services, capacity payments, transmission costs and also risk premiums. In an attempt to relieve future contracts rates, interest has shifted towards long-term contracts of 10-20 years that do not incur the risks of medium-term contracts.

Concerning the variations of forward contracts, a preferable option is to introduce them as standardized contracts. This contract form may be managed more easily by the Operator, while it may attract more consumers. In due time, when the forward market achieves satisfactory participation, contracts may become customized in order to push competition to a higher level.

Lastly, a basic prerequisite for a successful forward market is an efficient balancing market. This is because participants will enter into long-term contracts or costly investments only when they know they can rely on the Balancing Market when unable to perform their total contracted obligations. Figure 8-6 depicts APPA's (2009) suggested market model – it depicts the financial and energy flows in the energy market integrating bilateral contracts, the role of the balancing market and the information flow for operations.



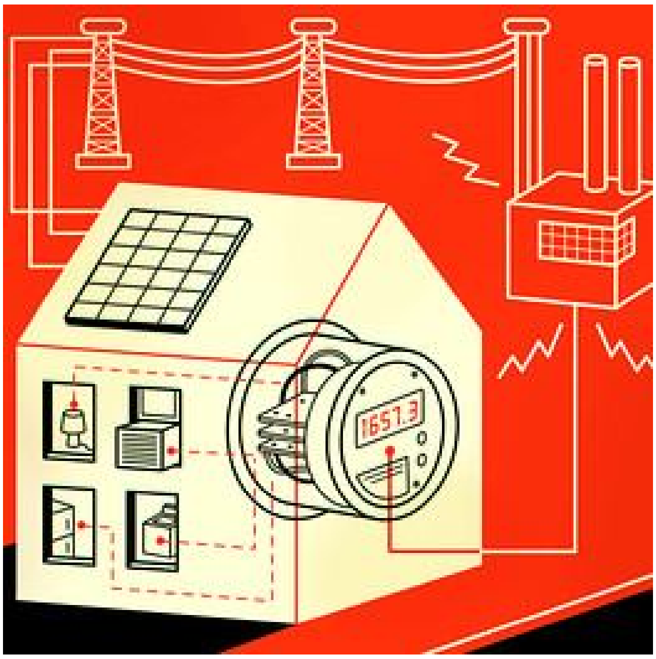

**Source: APPA (2009)**

**Figure 8-6: An indicative scheme of an electrical energy market with bilateral contracts**

### 8.2.2 Activating demand response

The potential role of an active demand-side in price forming has been in the spotlight of market analysts. One of the reasons for establishing reliability markets, i.e. ancillary services markets , is the absence of demand response (Ausubel and Cramton, 2010). Demand response schemes may include the reduction of a customer's consumption in times of increased SMP and/or activating processes requiring high amounts of energy during times of low SMP; for instance, smart grids may be used to activate washing machines at night when the system load is low. Customers benefit from lower electricity tariffs when providing this flexibility. An active demand response has the ability to alleviate price spikes in the spot market and thereby even contribute to sustaining the system stability. Under more careful analysis, this advancement may cause more radical twists in the market model. Namely, the act of a customer reducing consumption when desired is similar to the act of a generator offering energy to serve extra demand. Consequently, the demand response may be part of either a supplier's, an industrial (or other) customer's or a community's offer bid portfolio in the imbalances market. Joskow (2006) goes on supporting the consumers' rights for capacity payments related to the offering of their consumption response.

The introduction of demand-side response in the market means costly investments in infrastructure enabling generation-consumer interaction. For the moment, only non-regulated customers have hourly meters and are able to adjust their consumption in real time. The small, regulated customers do not possess such meters and cannot perform strategic demand response. In an international perspective, there is significant research onto "smart grid" technology, which is developing meters and grids interacting remotely that may enable automated consumption adjustments – Figure 8-7 depicts how the smart meter is connected both with a consumer's consumption and the generator. Despite the high costs of innovative infrastructure investments, Italy's ENEL and the UK went ahead applying them; thereafter, they created a greater variety of sophisticated tariffs, including load management or interruptible tariffs (reduced tariffs for consumers permitting adjustments of their consumption when needed) (Roques, 2008).




**Source: Campbell H. (2010)**

**Figure 8-7: The domestic smart meter**

A more conventional way of instituting demand response would be Joskow's (2007) proposal of establishing demand response contracts as call contracts. With these contracts consumers agree to contingent curtailments of their energy supplies when wholesale prices rise to a specified level. It appears that this option may be more compatible with the Greek market environment, where practically demand response is applicable only for the large non-regulated customers having hourly meters. However, even the response of these customers may help keep SMP prices to reasonable levels, and, thus, benefit all consumers.


**Source: GETTY (2010)**

**Figure 8-8: A common smart meter**

## *8.4 Capacity market revisions*

The Greek Capacity Adequacy Mechanism remunerating yearly participants at a steady and uniform price for offering their capacity is not subject to any current capacity requirement criteria, market performance indices, to new added capacity impact or emission profiling. It is, therefore, obvious that the country needs to adopt a capacity remuneration scheme that will actually respond to its current needs, support future investment planning, and enhance competition. A progressive scheme that can cover capacity costs, as well as promote a desired future fuel mix, is the mechanism of capacity auctions with additional resource adequacy requirements; this is described next.

As Joskow (2006) suggests, the capacity auctions may comprise a series of one or more future periods, where generators offer their capacity to suppliers. Through these auctions suppliers seek to guarantee the capacity they are attributed according to their customer portfolio. Suppliers pay generators for capacity at the market clearing price. The market clearing price equals the capital costs net of quasi-rents apparent in the energy market, as a result excessive gains in the energy market are extracted by the generator's capital costs recovery. This calculation gives inverse proportion for capacity and energy prices, and, hence, induces a double benefit to the market: On the one hand it hedges participants against price spikes, and on the other hand it mitigates market power. In addition, the capacity auctions offer greater reliability for investors planning, considering the uncertainty regarding future government policies, especially in relation to the peaking units. Moreover, suppliers and generators should have the option to form capacity CfDs, in order to offer a hedging tool against capacity price volatility. As a result, capital costs can be remunerated through a competitive mechanism instead of the roughly defined capacity payments that are currently applied.

A complementing measure adding greater value to the capacity auctions is the resource adequacy requirements. This measure obliges suppliers to cover a significant part of the capacity they are attributed with clean capacity, i.e. renewables or efficient units, and demand response, when demand response will be applicable to the Greek market. By defining the level of these requirements, regulators can promote an efficient fuel mix and help clean units receive higher reimbursement for operating, as opposed to less efficient units.

As an example, in a capacity auction all generators offer their capacity and consumers offer demand response for suppliers to bid for. Assume that a supplier is attributed 100MW to cover the needs of its customers and regulators oblige suppliers to cover at least 40% percent of their energy with clean capacity. Therefore, our supplier has to obtain through capacity auctions at least 40MW of wind capacity, solar capacity, other clean units, or demand response. For the remaining capacity that has to be covered, the supplier shall bid to auctions of low-cost units, like the lignite ones.

The proposed scheme, besides answering the need for a sophisticated capacity market set-up, it may help Greece build a more efficient unit mix through tresource adequacy requirements. Establishing a radical mechanism to promote an efficient fuel mix is of great importance. This is demonstrated by international benchmarks, indicating that stand-alone measures are just tinkering with the sustainability of energy (see Figure 8-9). The resource adequacy requirements force suppliers to develop a capacity portfolio that consists of a satisfactory level of clean energy or demand response. The significant contribution of such a measure is its ability to appraise energy efficiency in a competitive framework. Since resource adequacy requirements would increase the demand of clean capacity, efficient units would be paid the highest prices, while investors would respond to clear incentives in constructing RES or other energy-efficient units.


**Source: Le Canard enchaîné (2008)**

**Figure 8-9: "SEE THE DIFFERENCE!" – Humorous illustration of the limited differences achieved in France's "Grenelle" Environment Round Table in 2007 contrasting the "BEFORE" with the "AFTER THE GRENELLE" energy market status**

## *8.5 A reliable balancing market structure*

The importance of establishing a reliable balancing market has been discussed extensively in the previous Sections. It is indispensable, when considering the inability to store electricity and the inevitable deviations of injected and consumed energy. Moreover, a well-functioning balancing market can cover efficiently participants when needed, and hence mitigates risk and underpins forward markets, as mentioned above. Notwithstanding the need of a balancing market compensating participants efficiently, price levels should be at a lower level relatively to those of the SMP; this is because it should prevent participants from frequently relying to the balance market, or else participants would be encouraged to deviate from their schedule.

An important element to be taken into account for the Greek environment is that ancillary markets are far more susceptible to market power excesses, since in Greece the largest part of ancillary services can be provided by a limited number of generators. However, the appropriate market framework may overcome this problem.

In addition, a successful balancing market can prevent the incumbent from systematically driving high-cost units to the imbalances market. As described in the previous chapter, the incumbent uses to offer in the day-ahead market amounts of energy larger than it is actually possible, in an attempt to exclude expensive units from the day-ahead schedule; as this schedule formation is bound to leave a portion of the demand uncovered, high-cost units are inevitably called to produce in the imbalances market at prices lower than the SMP. Better efficiency in the balancing scheme may stop the current strategic expulsion of high-variable-cost units to the insufficient imbalances market, and distribute energy payments fairly among generators.

APPA (2009) prescribes a robust balancing market framework that may be applied in the Greek electricity market. The three principal features defining the proposed balancing market are a) price limits, b) the price formation process and c) the selection of participating generators.

With regards to the price limits, it is advisable to allow generators to offer energy at a price not higher than their Short Run Marginal Cost (SRMC). With this requirement, generators will be unable to profit more from the balancing market than the spot market, and thus lower the competitiveness and flexibility of the spot market. Moreover, units called to produce (systematically) in the balancing market would not be remunerated in prices lower than their SRMC, and thus will not face damages. Consequently, units will be incentivized to rely on the day-ahead market, and show more consistency between the schedule and their performance.

The price formation process should remain a single-clearing-price system. In this way, the market will not be abruptly distanced from its current framework. Moreover, this scheme will lead suppliers to extensive forward contracting in order to minimize their dependence on the balancing market.

Finally, it is advisable that the balancing market functions under a must-offer regime, meaning that both scheduled and unscheduled participants are obliged to participate. With a view to ensure the due participation of generators, the latter would be required to submit a schedule of planned maintenance and/or outages, and they would be compelled to follow it. This framework has the ability to deal with strategic withholding.

This balancing market structure appears to create a just balancing mechanism remunerating participants in a fair manner and addressing market power abuse. Ultimately, it co-optimizes offers across the energy and the ancillary services markets.

## 8.6 The proposed framework

This final section describes the overall framework proposed for the Greek electricity market. All propositions are presented along with the limitations they address, as well as their strong and weak points.

| Proposition | Description | Limitations Addressed | Strengths | Weaknesses |
|---|---|---|---|---|
| Preservation of public ownership<br><br>(see 9.2) | • Devolution of PPC in a number of companies, where independent firms, investors, or municipalities are invited to participate<br>• As a last resort, introduce VPPs or DCs if PPC preserves its assets<br>• Attribution of networks to independent System Operators | • High market concentration<br>• PPC's disproportionally varied fuel mix<br>• Inefficient unbundling of networks | • International success of similar schemes<br>• Preservation of public social policy<br>• Mitigation of political implications of mere divestiture of PPC's assets to independent firms<br>• Mobilization of the public and small investors | Greece's inexperience in alternative public ownership schemes |
| Bilateral contracting<br><br>(see 9.3) | Agreement between a supplier and a generator for delivery of energy at a specified price | • Vulnerability to fuel price volatility<br>• Vulnerability to SMP manipulation | • Historically proven and needed in markets internationally<br>• Offering an alternative choice to participants besides the day-ahead market<br>• Long-term fix of SMP formation<br>• Market stability | • Limited transparency<br>• Limiting scheduling flexibility |
| Introduction of forward markets<br><br>(see 9.3.1) | • A medium-term forward market (1-3 years)<br>• A long-term forward market (3< years) | • Market power abuse in price formation | • Proven to encourage bilateral contracts<br>• Market stability<br>• Higher consistency with long-range system planning<br>• The longer the term of contracts, the freer they are from high extra costs, such as those for ancillary services, capacity and | • Drop in day-ahead market liquidity |

| | | | | |
|---|---|---|---|---|
| | | | risk premiums | |
| Activation of demand response<br><br>(see 9.3.2) | • Introduction of smart meters and smart grids<br>• Issue demand response call contracts | • Balancing market deficiency<br>• Market inelasticity | • Higher market flexibility<br>• More power for the consumer side<br>• More efficient consumption<br>• Elimination of price spikes<br>• Sustain system stability | • Lack of very expensive infrastructure<br>• Attention needed in establishing a robust framework |
| Capacity auctions<br><br>(see 9.4) | • Capacity auctions for one or more future periods<br>• Optional CfDs<br>• Resource adequacy requirements | • Inadequacy of current capacity payments<br>• Market power abuse | • A competitive setup for capacity remuneration<br>• Promotion of an effective fuel mix<br>• Hedging against price spikes<br>• Greater reliability for investments planning | Attention needed in determining resource adequacy requirements |
| Effective balancing market<br><br>(see 9.5) | • SRMC as price limit<br>• Single-clearing-price<br>• Must-offer regime | • Inability to store electricity<br>• Systematic extraction of marginal units to the imbalances market | • Less reliance on the balancing market<br>• More consistency between schedule and performance<br>• Compatibility with current framework<br>• Encouragement of forward contracting | |

# Conclusions

This thesis has presented the current status of the Greek electricity market, identified its major limitations and proposed innovative initiatives that may be part of a roadmap towards an efficient electricity market structure. The proposed initiatives, which deserve further study, attempt to address the current requirement for mitigation of PPC's market power, the imperative to achieve Greece's environmental targets, the requirement for judicial price formation, the need for sufficient future investments, the market stability, and the protection of participants from undue risks. The proposed initiatives include an innovative ownership regime counterbalancing the current highly concentrated market, the introduction of forward markets accommodating bilateral contracts outside the pool, the establishment of demand response, a sophisticated capacity market scheme, and a reliable balancing market.

The study of the electricity markets internationally delineates a common underlying reality: A well-functioning electricity market is sustained by political commitment. Only political commitment may keep electricity liberalization on the right track to achieve its original objectives of promoting entrepreneurship, upgrading infrastructure efficiency, and providing better prices for consumers. Reviewing the liberalization path of the Greek electricity market to-date, one does not encounter a considerable number of new investors making high profits, the networks are in need of upgrade, the fuel mix has not become really efficient, and consumers are facing distorted pricing schemes. As a result, the political directions driving market liberalization should strive to align with the initial targets, without resulting to micromanagement of the electricity market.

Market monitoring is another fundamental issue related to political leadership. Regulation alone is unable to address certain competition issues, while competition is unable to address structural issues of the market, and especially non-compliance to regulation. These two different perspectives call for a fine balance between regulation and competition. of the latter is yet to be achieved in the Greek electricity market, and there is an apparent need for the state to vest RAE with wider authority. RAE must be able to perform this key role and ensure a harmonious market function, while supporting legislators in adjusting the statutory framework to best serve the needs of all participants.

It is emphasized that the effort of forming an efficient electricity market isbe continuous, since a) the market is intrinsically affected by different developments, such as fuel prices and financial cycles, and b) a regulatory framework requires time to show its true effects, then be assessed, and finally improved to address its shortcomings. We hope that this thesis provides some useful ideas to pave the road towards the success of this critical national effort.

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