ESTABLISHMENT, ORGANISATION AND PILOT OPERATION OF THE HTSO

Power Exchange Code User Guide Draft

8 October 2000

TABLE OF CONTENTS

1. INTRODUCTION

This document is a deliverable of Task 4 for the Project for the Establishment of the Hellenic Transmission System Operator. It contains two parts. The first part is a description of the newly restructured electricity industry in Greece and contains:

- A summary description of the new industry structure;
- A summary of the framework of Codes and agreements entered into by players in the newly restructured industry, and the relationships between those documents and the relationships between the players;
- A summary description of the System Trading Arrangements (STA) used to establish the arrangements for trading wholesale electricity in Greece (in particular, this section describes the rules for how Suppliers serve the load of their final customers, how other generators in Greece can participate in the trading arrangements, and how energy for export is purchased); and
- A summary description of the workings of the Greek Power Exchange Code.

The second part of this document is a series of responses to frequently asked questions about the market structure. This part answers the following questions:

- What does net settlement mean?
- How do bilateral contracts work?
- How does the HTSO ensure adequate installed capacity?
- How does the HTSO ensure adequate available capacity?
- How are SMPs determined?
- How do Constrained-On and Constrained-Off Payments work?
- How are Settlement Quantities determined?
- How are Ancillary Services handled?
- How are imports/ exports handled? and
- What charges and payments are settled under the Power Exchange Code?

The purpose of this document is to be descriptive. It is supplemental to the main deliverable of Task 3 of the HTSO establishment project, being the “Detailed Definition and Description of Electricity Trading System Arrangements in Greece”, although it covers much of the same material. Like that document, this manual does not have legal status; its purpose is solely to act as a guide to the new industry structure. The Codes, together with the Authorisations issued by the Minister of Development to entities involved in the generation and supply of electricity and other associated agreements, constitute the legally binding requirements, rights and obligations for participation and operation of the STA and the operation and control of the transmission system.

2. THE NEW INDUSTRY STRUCTURE

2.1. Overview

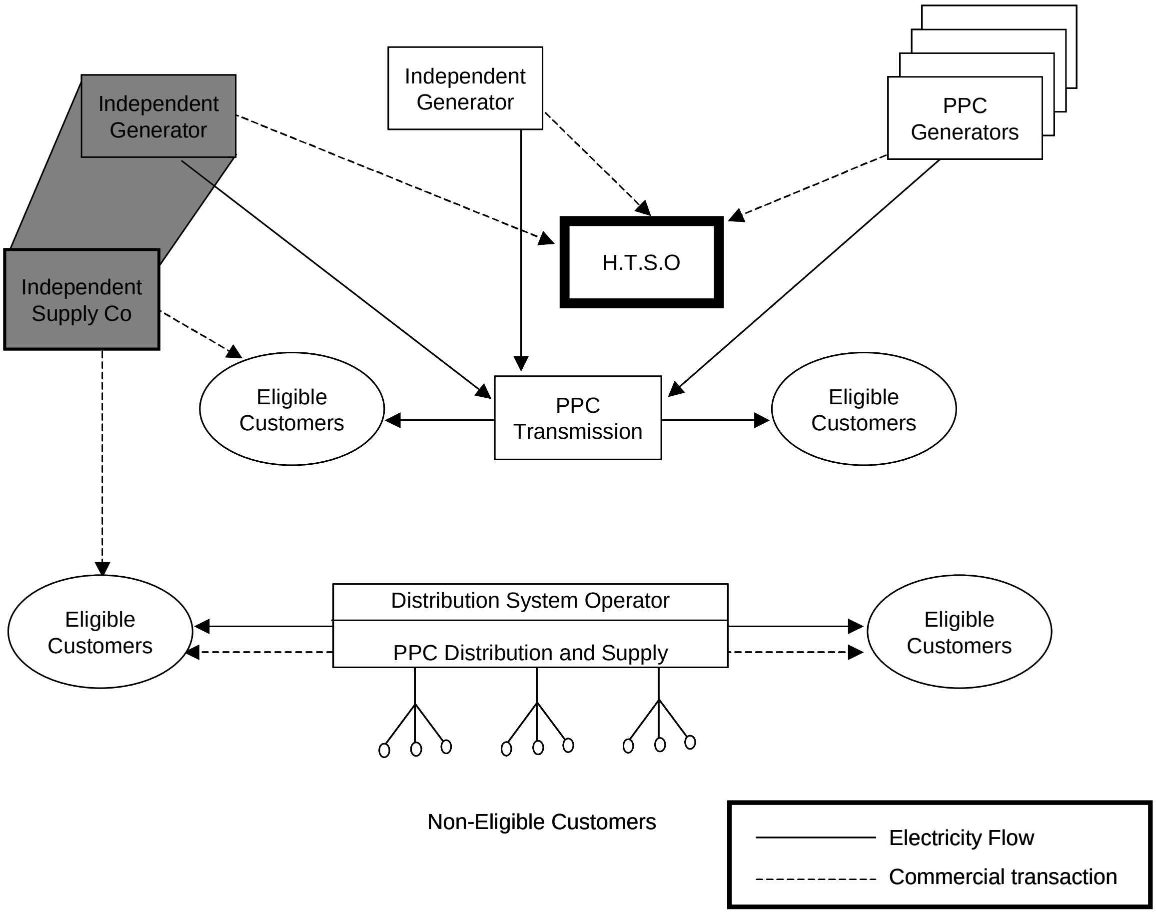
The Electricity Law has introduced a new structure for the electricity industry in Greece, where there is a degree of competition in generation and supply. This structure, which applies only to the inter-connected system, has been introduced in order to comply with the EU Electricity Directive, and the extent of the competitive sector will need to increase to meet the requirements of the Directive.

Central to these changes is the creation of the HTSO, an independent system operation organisation. The HTSO will take over from PPC the responsibility for system planning and operation, including despatch of generators and will also take responsibility for the operation of the new trading arrangements.

The HTSO will be the key institution in facilitating the entry into the market of independent generators, who are also permitted to compete directly for sales to certain customers, termed Eligible Consumers.

This new structure is summarised in Figure 2.1

Figure 2.1
New Industry Structure



The key feature of this new structure is the distinction that is created between the different sectors of the electricity industry:

- generation, where competition is permitted between different generators.
- transmission (wires), where there remains a natural monopoly in the ownership of PPC.
- distribution (wires) where there remains a natural monopoly in the ownership of PPC
- supply (sales to customers) which is opened to competition, initially to a limited category of "Eligible" Customers.

2.2. The New Entities and their Functions

In this new structure, the main entities and their functions are as described below.

HTSO: The organisation has been created to take over PPC's functions in respect of system planning, system development, and system control, with PPC remaining responsible for actually carrying out development work and physical operation. The HTSO will also have responsibility for the new activities of granting access to system users, and the operation of the new trading arrangements. The HTSO will be established in a way that is intended to ensure its independence from undue influence by PPC or independent generators or suppliers.

PPC: Continues to be responsible for all the existing generation plants and for the ownership and physical operation of the transmission system and the distribution system. For accounting and regulatory purposes, PPC is "unbundled" between:

- generation
- transmission
- distribution
- supply

Independent Generators: these will be authorised to sell power in Greece, providing they are located in the EU and satisfy all necessary environmental, etc requirements. They will participate to the full extent of their output in the system trading arrangements. Independent generators can sell into Greece even if they are located outside of Greece, providing they are located in the EU and can obtain access to inter-connectors and all other necessary transmission capacity.

Independent Suppliers: these will be allowed to compete to sell power to Eligible Customers. Such suppliers cannot simply be traders, as the Law requires that they are the owners of generating capacity in Greece or another EU country sufficient to meet the demands of their contracted consumers. It is likely that in most cases generators will also operate as suppliers.

Eligible Customers: these will initially be limited to the very large customers, many of them connected directly to the transmission system. As competition is allowed to expand, eligibility would be expanded to include more customers.

Non-Eligible Customers: these will continue to have to purchase all their requirements from PPC.

Renewable Generators are the subject of special arrangements, under the Law, through which they contract directly with the HTSO, The terms of these special arrangements are specified in the Law, and are related to tariffs. Any extra costs incurred over the cost of conventional generation will be recovered by the HTSO through the "Uplift" arrangements in the PEC, described later in this Guide.

2.3. Regulatory Arrangements

An important part of these new arrangements is the creation of a new regulatory agency for the industry, the Regulatory Authority for Electricity or "RAE". This organisation is given responsibility for regulation of many of these new competitive activities, under the auspices of the Ministry of Development. Together, they are responsible for:

- issuing of authorisations to the HTSO, and to the transmission, distribution, generation and supply entities;
- approval of the Operating Code and Power Exchange Code;
- approval of the transmission control agreement;
- regulation of prices
- dispute resolution, etc.

The operation of these new regulatory arrangements will be crucial to ensuring the effective operation of the new market arrangements, and in particular to ensuring that independent generators and suppliers are treated in a fair and non-discriminatory way.

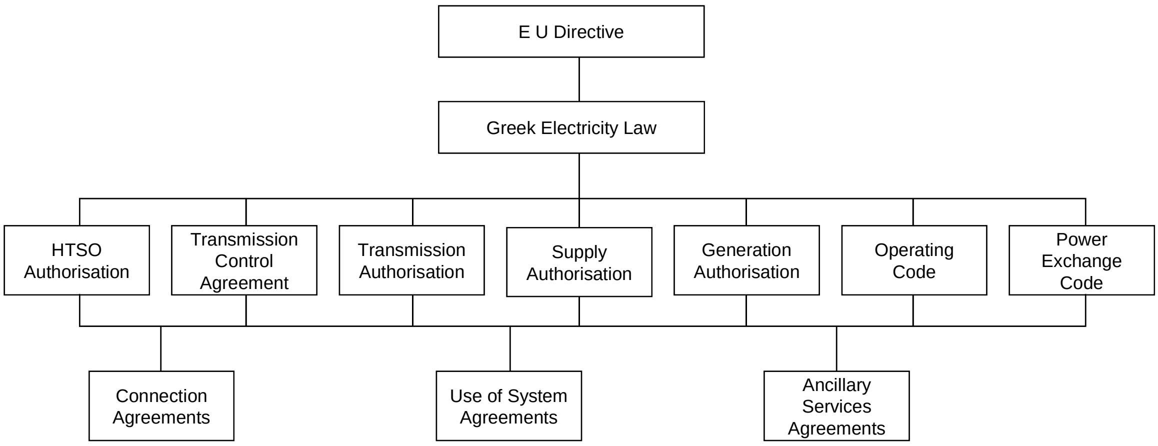
3. FRAMEWORK OF CODES AND AGREEMENTS

3.1. Overview

The new electricity industry structure in Greece will allow participation by independent generators and suppliers, and it is necessary that their participation is permitted on a non-discriminatory and competitive basis. To ensure this, it will be necessary that some things that were previously carried out as actions internal to PPC are now established as arms-length commercial transactions, even where the parties may be in different parts of PPC. As noted in the previous Chapter, new regulatory arrangements are being put into place to ensure that this new structure works effectively.

These changes mean that it is necessary to introduce a number of new agreements, Codes, and other instruments in addition to the Power Exchange Code, and the purpose of this Section is to provide a review of all these provisions. Partly these instruments are required for commercial reasons, to ensure that the transactions take place on a commercial basis, and partly the instruments are required for regulatory reasons. Though this new framework may appear complex, experience elsewhere has demonstrated that these or similar instruments are necessary to make the new industry structure work effectively. Figure 3.1 illustrates the hierarchy of Laws, Codes, and agreements that will be required.

Figure 3.1
The Framework of Law, Codes, Authorisations and Agreements



The EU Directive is the driving force for much of the structural change, and implementation of the Directive has now been written into the new Greek Electricity Law. The Law itself refers to a number of the Codes, agreements, and other instruments, in particular:

- the Power Exchange Code and the Operating Code are both specified in the Law, including their coverage and provisions for their preparation and approval;
- the Transmission Control Agreement that sets down the relationship between the HTSO and the transmission company is specified in the Law; and
- the new requirement for authorisations for the different entities is also specified in the Law, along with provisions on the authorisations' content, etc.

A number of other agreements have been prepared as part of this project work, and thought they are not individually specified in the law they are important parts of the new framework:

- transmission connection agreement;
- transmission use of system agreement;
- ancillary services agreement.

In the following section we provide summaries of each of these documents.

3.2. Summary of the Codes, Agreements, and Authorisations

The Power Exchange Code is dealt with in more detail later in this Guide, and the Operating Code is the subject of a separate Guide. Below we summarise the objectives, parties, coverage, and key points of all the other documents referred to above.

3.2.1. The Transmission Control Agreement

There will be a single Transmission Control Agreement (TCA), between the HTSO and the transmission owner (PPC's TBU), and Table 3.1 summarises the main elements of the proposed document. Though it will be a commercial agreement rather than a Code applied by Law, the Law requires that its terms be approved by the Minister/RAE.

Table 3.1:
Summary of the Transmission Control Agreement

Type of Document	Commercial agreement, subject to regulation.
Objective	To govern the relationship between the transmission owner and the HTSO, so as to ensure that the HTSO is able effectively to control the operation and development of the inter-connected system.
The "Parties"	1. the HTSO 2. the transmission owner (PPC's TBU)
Coverage	Operation of the system, maintenance and performance standards, new connections, procedure for system development, and fees.

The key elements of the agreement that has been drafted are those designed to ensure that the HTSO has the necessary degree of control, and that it can ensure effective development, maintenance, and physical operation of the inter-connected system. It is important to note that the TCA does not cover any transmission assets not forming part of the inter-connected system.

3.2.2. Transmission Connection Agreement

These connection agreements will be required in all cases where a party is connected to the transmission system, and Table 3.2 summarises the main elements of the proposed model. Broadly similar terms would apply whether the connected party is a generator or a load.

Table 3.2:
Summary of the Connection Agreement

Type of Document	Commercial Agreement, at regulated terms.
Objective	To ensure that the connection is properly provided, maintained, modified, etc, at terms that are effieicent and fair to the connected parties.
The "Parties"	This is proposed to be a three-party agreement: 1. the HTSO 2. the transmission owner 3. the connected party.
Coverage	Construction, maintenance, modifications, and fees.

An important feature of the proposed document is that it is drafted as a tri-partite document, and this has been done to ensure that the three parties involved are tied adequately together. It is believed that this addresses the issues more effectively than would be the case with two separate contracts between the pairs of parties.

3.2.3. Transmission Use-of-System Agreement

Use of the system will be essential to those acting as suppliers and to generators, and it is proposed that a use-of-system agreement on similar terms will be provided to all these users of the system. The key elements of this document are summarised in Table 3.3.

Table 3.3:
Summary of the Transmission Use-of-System Agreement

Type of Document	Commercial Agreement, at regulated terms.
Objective	To regulate the terms and charges for use of the system.
The "Parties"	1. the HTSO 2. the Users (either a generator or a supplier)
Coverage	Standard terms, including fees as determined by the regulatory authorities.

It is proposed that, in order to ensure consistency in terms, all users will sign up to a common agreement, and that new users will join the arrangement by signing an accession agreement. Fees for use of the system will be set by the regulatory authorities from time to time. It is envisaged that the same fees structure will automatically apply to all users, their specific fee being determined according to their type of use.

3.2.4. Ancillary Services Agreement

Ancillary services are those services provided, principally by generators, to ensure a stable and reliable power system. Table 3.4 summarises the key elements, including the services that are envisaged to be covered.

Table 3.4:
Summary of Ancillary Services Agreement

Type of Document	Commercial Agreement
Objective	Provision of all necessary system support services
The "Parties"	1. the HTSO 2. generators, and perhaps others providers such as interruptible load.
Coverage	Will deal with the definition, scheduling and payment for the following services: 1. AGC 2. Reserve 3. Reactive Power 4. Black Start

It is envisaged that, initially at least, these services will be provided on the basis of medium-term contracts, and that the first tranche of contracts would be at regulated terms. Subsequently, new contracts could be procured by open competitive tender, if there is sufficient competition in the generation market. The cost of the agreements would be recovered by the HTSO through the Uplift element of the PEC.

3.2.5. The Authorisations

The Law requires that, with some smaller exceptions, all domestic participants in the electricity industry must obtain authorisations from the Ministry of Development, on the basis of opinions from RAE. The main elements that are envisaged for these authorisations are summarised in Table 3.5.

Table 3.5:
Summary of Proposed Authorisations

Type of Document	Regulatory Instrument
Objective	To ensure effective control of entry to the industry and regulation of behaviour of participants.
The "Parties"	Issued by Ministry of Development/RAE. To be held by: 1. the HTSO 2. the Transmission Owner 3. the Distribution Owner 4. all Generators, except for smaller exemptions 5. all Suppliers, except for some possible exemptions.
Coverage	Coverage and terms vary from Authorisation to Authorisation. Include requirements for compliance with Codes, provision of information, accounting, etc, and may include other provisions such as price control, participation in certain agreements, etc.

There will be separate authorisations for the HTSO, the transmission owner, the distribution owner and operator, suppliers and generators. The key features will vary from case to case, but it is envisaged, for example, that these authorisations would be the means through which is enforced:

- requirement on suppliers for generation ownership and reserve; and
- price control processes, where appropriate.

4. SUMMARY OF SYSTEM TRADING ARRANGEMENTS

The implementation of the System Trading Arrangements (STA) introduces several important changes in the electricity sector. Most notably it creates the mechanisms by which new Suppliers, new generators, international Participants, and PPC can buy and sell electricity. These mechanisms include procedures for scheduling and dispatching electricity generation and for determining a transparent and verifiable price at which imbalance energy trades.

The trading arrangements are designed to ensure that the Hellenic Transmission System Operator (HTSO) can operate the system in an efficient and reliable manner and that generators have an incentive, through market prices (System Marginal Prices or SMPs), to follow its instructions.

The STA also gives generators market-based incentives for production and investment. It is designed to enable the efficient entry of private generators to meet the electricity needs of Eligible Customers without losing the benefits of the integration present in the existing system and without imposing large additional costs.

The largest Participants in the STA will initially be PPC generation and PPC supply, but this may change as private suppliers and private generators become Participants.

The principal characteristics of the design of the STA, in the lexicon of other restructured electricity sectors around the world, are:

- *An Independent System Operator and independent Market Operator (ISO and PX)*: The HTSO is responsible for both system and market operations and is fully independent from PPC in accordance with the EU Directive.
- *An Offer-based Dispatch*: Scheduling and Dispatch of generating Units is based on Offers received by the HTSO for the full declared available capacity of those Units. The HTSO conducts a security-constrained least-cost Dispatch of all offered generating capacity and does not take into account any contract positions of generators in its Dispatch of the system. Contracts between market participants are therefore financial, rather than physical, in nature.
- *A single price for imbalance energy*: A unique price of energy (SMP) is set for the entire interconnected transmission system, in every hour, ie, prices are not locational. The SMP in each hour is determined, in principle, by the marginal Offer cost of supplying an additional MW of energy to the system.

- *SMPs are determined once for each hour:* The STA consists of a single and separate market in each hour, in which prices and quantities are determined after the fact (ie, ex-post) on the basis of actual generator availability and load conditions.[1]

- *Restrictions on Offer prices:* The Energy Regulatory Authority (RAE) requires that for all Generators located in Greece, regardless of ownership, the Offer prices for each offered Unit must reflect the true and auditable variable and start-up costs of that Unit.

- *Gross settlement in respect of contracts, net settlement in respect of ownership:* All electricity generated or consumed is sold by Generators, bought by Purchasers, and settled by the HTSO. The HTSO does not consider independent contractual arrangements between Participants when carrying out its settlement of STA transactions. The HTSO does, however, consolidate invoices and remittances to Participants owned by the same parent entity. Suppliers, which are both Purchasers and Generators in the STA are therefore invoiced or paid for their net financial imbalance. (Each Supplier is treated as a separate Generator and Purchaser in the STA – in this way it is possible for the HTSO to conduct a least cost Dispatch of the full available capacity of Suppliers and not just the capacity net of their final customer load.)

- *Cost-of-service regulation of the ISO/PX:* The HTSO is a for-profit entity. It makes a regulated margin on the cost of the services it provides, and it passes all its costs through to Participants.[2]

The remainder of this section describes the Participants of the STA and the key features of how the STA operates, including how it relates to the scheduling and Dispatch of generation.

4.1. Participants in the STA

All electricity delivered to or taken from Greece's interconnected transmission system is bought and sold through the STA.[3] Only "Participants" are entitled to buy and sell electricity in the STA. A Participant is an entity that has signed a Participation Agreement,

---

1 In some restructured markets, this arrangement is known as a "single-settlement system" in which the market is a "spot" market.

2 At least initially, the HTSO will not make any unregulated profits from the *outcomes* of the services it provides, ie, it will not be subject to performance-based regulation like some other ISOs/Power Exchanges are. This affects the trading arrangements because it means that each of the ways in which the HTSO fulfils its functions is specified in the Codes, and is not at the discretion of the HTSO. For example, the HTSO must schedule and dispatch the system in a way that is both security-constrained and least-cost.

3 Electricity sold by Distribution-Embedded Units will also trade through the STA.

thereby agreeing to be bound by the Power Exchange Code as a condition for obtaining from the Minister of Development one or more of the following:

- an Electricity Supply Authorisation; and / or
- an Electricity Generation Authorisation.

There are two principal categories of Participants: Purchasers and Generators.

4.1.1. Purchasers

The category "Purchasers" comprises[4]:

1. Suppliers authorised in accordance with the Greek Electricity Law to sell electricity to final customers in Greece; and
2. Exporting Purchasers that purchase electricity in the STA for the purpose of export from Greece to supply customers in another country.

A Supplier is an entity authorised to carry out the function of electricity supply to Eligible Customers, including importation of electricity by an Eligible Customer for its own use, or in the case of PPC, electricity supply to Non-Eligible Customers. PPC has an exclusive right and an obligation to serve Non-eligible Customers. Other Suppliers have the right to serve Eligible Customers and PPC has the obligation to serve Eligible Customers if they are not served by other Suppliers.

To be an Exporting Purchaser, it is assumed that an entity must also be a domestic Generator (see below). Special rules limit the amount of energy an Exporting Purchaser can export.

4.1.2. Generators

The category "Generators" comprises:

1. domestic generating entities owning power plants located in Greece, and holding an Electricity Generation Authorisation; and
2. foreign generating entities owning power plants located outside of Greece, where they hold a Greek Electricity Supply Authorisation.

[4] The use of the term Purchaser is used only to ensure clarity in the Trading Arrangements, and it is *not* intended that this is a new category requiring a special authorisation in its own right. As explained in the Codes, the category of Participant covered by the term "Purchasers" comprise entities that hold either a Supply Authorisation or a Generation Authorisation (in the case of an Exporting Purchaser). This point can be further clarified through the use of appropriate terminology when the Trading Arrangements are translated into Greek.

All domestic Generators are required to hold Electricity Generation Authorisations under the terms of Article 9 of the Greek Electricity Law. There is no requirement that all domestic Generators must also be Suppliers. However, *all Suppliers must also be Generators* (in addition to being Purchasers): every authorised Supplier must own adequate generating capacity in accordance with the Greek Electricity Law[5]. It must also provide long-term confirmation as to the necessary arrangements for reserve generating capacity in accordance with the Greek Electricity Law. In addition, a Supplier that provides energy from generating capacity located in another country must arrange the necessary transmission capacity for the transmission of electricity.[6]

4.1.3. Non-Interconnected Islands

Entities either generating or consuming energy on the non-interconnected islands do not participate in the STA. Such an entity will only participate if and when the island it is located on is joined to the interconnected transmission system.

4.2. Net Settlement

In the STA, and as indicated above, all entities that sell electricity are known as Generators and all entities that buy electricity are known as Purchasers. Suppliers, in accordance with the Greek Electricity Law, are both Purchasers and Generators. Exporting Purchasers are also both Purchasers and Generators.

For simplicity *in the description of the STA, the roles of Purchaser and Generator are always separated*. All electricity generated is described as being sold through the STA and all electricity consumed is described as being purchased through the STA. The HTSO keeps track of which parent entity owns each Participant and, when it sends out invoices or makes payments, it consolidates the transactions for each owner so that only one net invoice or

[5] According to Article 24 of the Greek Electricity Law every authorised Supplier must own adequate generating capacity installed in a Member-State of the EU and provide long-term confirmation as to the necessary reserve capacity within the EU.

[6] When required, and to the minimum extent possible, a special division of the HTSO also participates in the STA. It is known as the Special Participant and is able to Participate as both a Purchaser and a Generator, as required. Its involvement is minimal and is stated here only for completeness. Its role is clearly defined and limited to the following two purposes:

- Very small generators, located in Greece, and exempt from the obligation to obtain an Electricity Generation Authorisation in accordance with Article 10 of the Greek Electricity Law, are represented in the STA by the Special Participant.
- Very small supply entities, exempt from the obligation to obtain an Electricity Supply Authorisation in accordance with Articles 24.3 and 24.4 of the Greek Electricity Law, are represented in the STA by the Special Participant.

The net cost of the Special Participant, if any, is passed through to Participants as part of an Uplift charge.

payment is sent. In respect of Participant ownership therefore, the HTSO conducts "net settlement".

Sections 6 and 7 of this document illustrate transactions that can be made in the STA; both in the case of a Supplier, where the Purchaser and Generator are owned by the same parent entity, and in the case of a bilateral contract, where a Purchaser has contracted with a third party Generator.

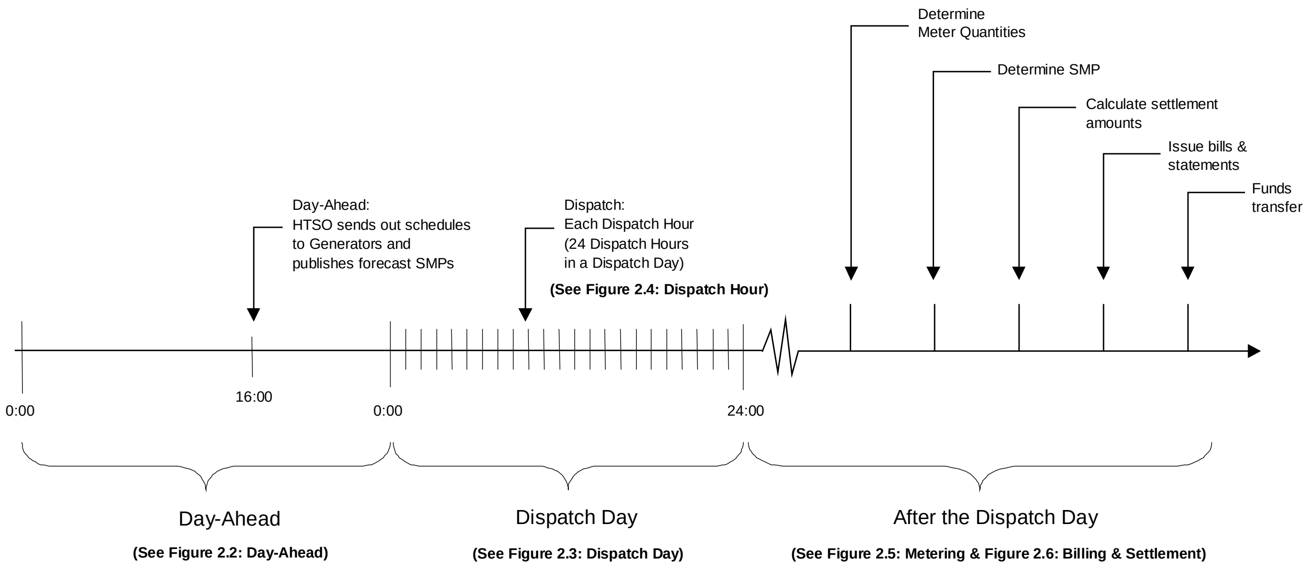
4.3. Summary of STA Timeline

The STA consists of five steps. These steps are summarised in the remainder of this section.

1. The first step is a day-ahead forecast. Generators make Offers, the HTSO makes a load forecast, and Exporting Purchasers schedule exports for the following day. From this data, forecast generation quantities, forecast SMPs and international interconnector schedules are calculated by the HTSO and advised to Participants. This process also determines the merit order for the real-time Dispatch.
2. The second step is the real-time Dispatch of Generators by the HTSO to meet real-time load on the system. This occurs throughout every Dispatch Hour on the Dispatch Day and determines the actual quantities of energy traded.
3. Metering quantities are then verified and finalised. Afterwards, the SMPs, at which the energy quantities in the Dispatch are traded, are determined, using actual Unit availability and actual system load. Since this occurs after the Dispatch, prices are known as "ex-post".
4. The fourth step occurs after the SMPs are calculated. This step consists of provisions for making payments to Generators in the legitimate but infrequent instances in which the Dispatch quantities and SMPs might not be consistent. To "not be consistent" means, in principle, a circumstance in which a Generator would be better off to produce a different amount than that it was instructed to produce by the HTSO, given the SMP.
5. The fifth step involves verification and finalisation of settlement amounts, determination of penalties and other charges, if any, and a monthly cycle of settlement and billing activities.

The following is a summary timeline of the five steps of the System Trading Arrangements:

Figure 4.1: Summary of Timelines



4.3.1. Timeline: Day-Ahead

During the day-ahead of Dispatch, the HTSO produces two forecast schedules for electricity production for the following day: an "unconstrained" schedule and a "constrained" schedule. Generators offer their energy, and in each of the schedules the HTSO accepts the cheapest Offers necessary to match its forecast of demand, including transmission losses, plus scheduled exports, for the following day. The Offers of Generators specify price and quantity parameters to describe their availability.

In determining the forecast schedules, the HTSO does not take into account the contract positions of Participants. The first of the schedules also ignores the effect of transmission constraints and is thus known as "unconstrained". It is produced so as to determine a single forecast SMP for Greece, for each hour of the Dispatch Day. Forecast SMPs are set at the Offer prices of the most expensive accepted flexible Unit(s) in each hour, so in principle no-one who offered, and whose Offer was accepted in this schedule, is selected to run at a price below their Offer price. The second of the schedules includes the effect of transmission constraints and is thus known as a "constrained". It is produced so as to determine forecast production of energy and Operating Reserve by each Unit for each hour of the Dispatch Day.

The day-ahead forecasting process occurs once a day and within that day there are a number of deadlines:

- The HTSO publishes its load forecast at 11:00 to assist Generators plan their availability. It also determines its Operating Reserve requirements at this time.

- Next, all Offers from Generators and all export schedules from Exporting Purchasers must be received by the HTSO before 12:00. This deadline is designed to allow the HTSO sufficient time to advise inflexible plants well in advance of the actual Dispatch.

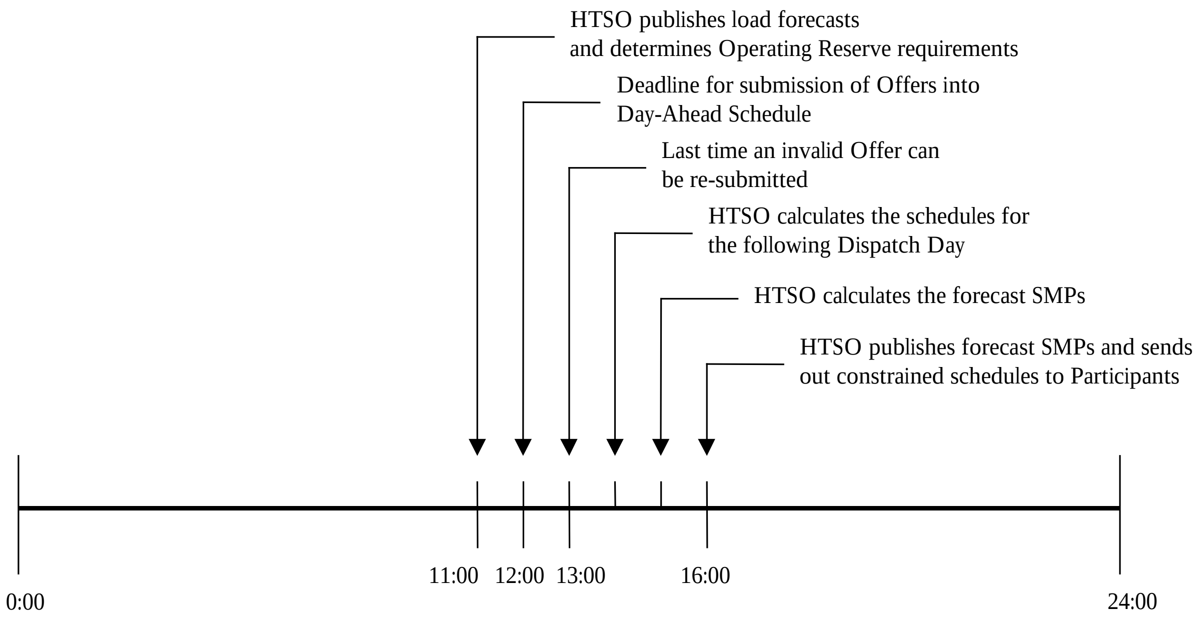
- The HTSO notifies Generators by 12:30, indicating whether the data contained in their Offer was valid or invalid. Generators who have submitted invalid data follow procedures for re-submission and must re-submit by 13:00.

- Next, the HTSO calculates the forecast unconstrained and constrained schedules for the Dispatch Day. In the constrained schedule, the HTSO selects providers of Operating Reserve, while minimising total cost and utilising those sources available as declared by Generators with which it has pre-arranged Ancillary Services contracts.

- After the HTSO has calculated the forecast unconstrained schedule and before 16:00, the HTSO determines forecast SMPs based on the results of that schedule.

- At 16:00, the HTSO produces a list that details the forecast constrained schedule and forecast SMPs for each Dispatch Hour of the following day. Generators are sent a subset of the list, showing the schedule for their Units only. The HTSO also sends Purchasers a list showing how much energy their customers are forecast to consume and how much they are forecast to be charged in each hour. Schedules for the use of the interconnectors with foreign countries are produced at this time and the forecast SMP for each hour is published and made available to the public.

Figure 4.2: Day-Ahead



4.3.2. Timeline: Dispatch Day

The HTSO may instruct available Units in Greece to start-up and synchronise at some point during or before the Dispatch Day to ensure adequate generation capacity is available for the real time Dispatch of the system. Generators are obliged to follow these instructions.

In real time, system load, generation availability and other constraints may change from those forecast day-ahead. Although these changes are normally not significant, they must be accounted for so that the transmission system is operated reliably. Accordingly, a separate Dispatch in each Dispatch Hour determines the actual energy quantities dispatched from Units in Greece to meet actual demand on the system. The Dispatch is determined according to the merit order established day-ahead from the prices in the Offers. The Units have to obey their Dispatch Instructions in real time so as to keep the transmission system stable.

Scheduled Generators are not able to resubmit the quantity component of their Offers between the time the Offer was submitted and the Dispatch Hour unless they have a "legitimate" reason to do so. A legitimate reason is a prior approval by the HTSO, or an unexpected (forced) outage that renders some or all of the capacity of the Unit unusable or hazardous to use for reasons of safety or protection of physical equipment. The HTSO may only issue prior approvals for reasons relating to unpredictable external factors such as wind strength in the case of wind-powered Units. Offer revisions that are not demonstrably legitimate result in penalties.

Under no circumstances may the price parameters of an Offer change between the time of submission into the day-ahead forecast and the actual Dispatch Hour.

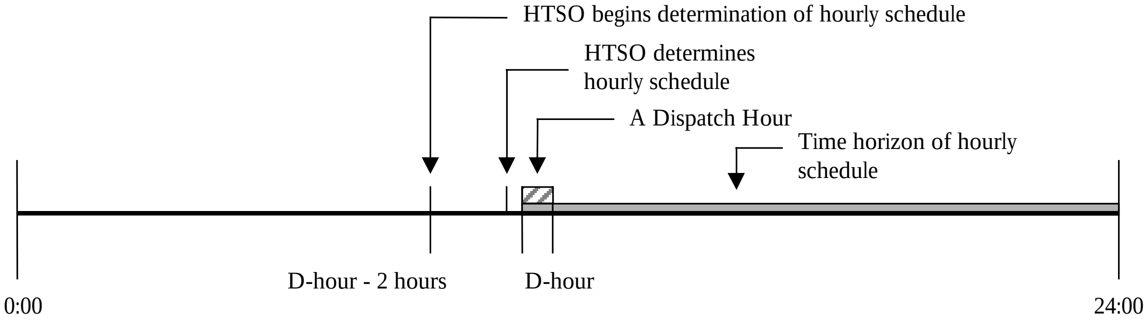
Scheduled use of the interconnectors is locked-in from the day-ahead schedule.

Two hours before the Dispatch Hour, the HTSO begins to calculate the Dispatch. This time period is designed to allow the HTSO enough time to analyse Offers, prior to issuing Dispatch Instructions. Irrespective of this two-hour period, the HTSO always endeavours to use the latest availability and other system information to determine Dispatch Instructions so as to maximise system reliability and minimise the cost of Dispatch.

Just prior to the start of each Dispatch Hour, the HTSO finalises an updated schedule of expected generation for the remainder of the Dispatch Day. This schedule is used mainly for the HTSO's own planning purposes but any updates are advised to the Generators concerned.

Within the Dispatch Hour, the HTSO calculates the real-time (final) Dispatch.

Figure 4.3: Dispatch Day

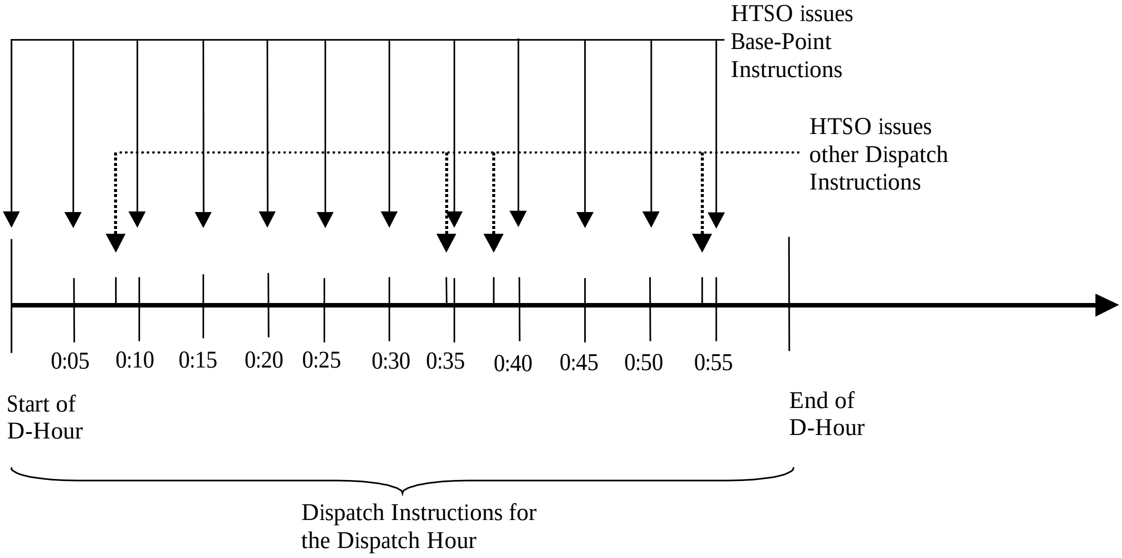


4.3.3. Timeline: Dispatch Hour

In making the calculation of real-time Dispatch, the HTSO continues to use the merit order as determined day-ahead and it utilises real-time system status information, including measurements of actual system load and any re-declarations of Unit availability. Every 5 minutes, the HTSO recalculates Base Point Instructions for each Unit and notifies each Unit of their new level of instructed output. The objective of the Dispatch is to minimise cost (as represented by the Offers) subject to system security and other constraints, ie, including all transmission system constraints.

Between the 5 minute Base Point Instructions, the HTSO issues other Dispatch Instructions, for example, regulation instructions to Units on automatic generation control (AGC), and instructions to activate Operating Reserve if system conditions suddenly change and Spinning Reserve or Standing Reserve is called upon.

Figure 4.4: Dispatch Hour

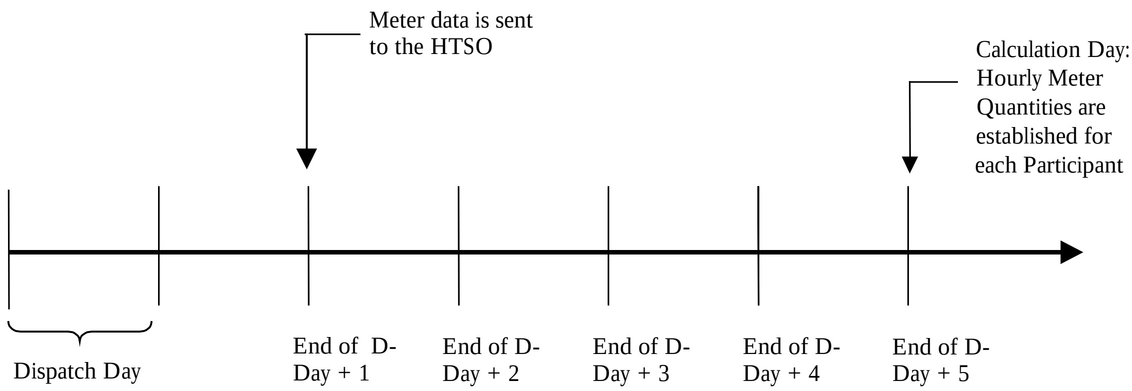


4.3.4. Timeline: Metering, Ex-Post Price and Settlement

By the end of the day following the Dispatch Day, all metering data in respect of the Dispatch Day must be sent to the HTSO.

The day five days after the Dispatch Day is known as the Calculation Day. In its role as market operator, the HTSO never takes title to the electricity traded, it acts as a financial clearing-house, matching sales to purchases each Calculation Day. During this day the HTSO first resolves any disputes and/or inconsistencies, and determines the final hourly Meter Quantities of energy supplied and consumed by each Participant in each hour.

Figure 4.5: Metering Cycle



Next on the Calculation Day, once each Meter Quantity has been determined, the HTSO calculates the SMPs; the prices at which energy trades in the STA.

In calculating SMPs, the HTSO first calculates an ex-post unconstrained schedule for each Dispatch Hour. The calculation of this least-cost schedule is done independently for each Dispatch Hour and uses actual Unit availability, actual Offer prices and metered system load from each Dispatch Hour. It ignores the effect of transmission constraints in the same way the day-ahead unconstrained schedule does. SMPs for each hour are then set at the Offer prices of the most expensive accepted flexible Unit(s) in the ex-post unconstrained schedule.

In addition, if a Unit fails to comply with a Dispatch Instruction, it may face penalties. These penalties are determined on the Calculation Day.

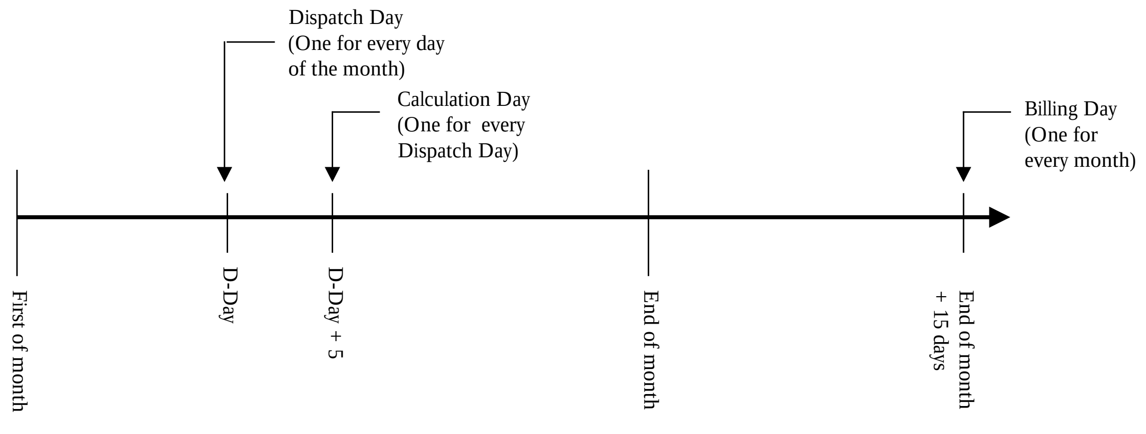
Finally on the Calculation Day, the HTSO determines the final amounts to bill or credit each Participant for energy bought and sold for the Dispatch Day.

4.3.5. Timeline: Billing

Fifteen days after the last Dispatch Day of the month is the Billing Day, the day on which any remaining settlement amounts are calculated and the total bills or credits of each Participant for the month are aggregated and sent out.

Funds due must be transferred on or before the day fifteen days after the Billing Day.

Figure 4.6: Billing and Settlement Cycle



4.4. Other HTSO Responsibilities

As part of its job as system operator and market operator and in addition to the tasks summarised above, the HTSO assists the RAE to ensure there is adequate generation capacity and monitors Participants' compliance with the terms of their Authorisations, procures Ancillary Services, fulfils its obligations with respect to hydro generation, and follows standards regarding information disclosure and metering. In addition, it administers the calculation, billing and settlement of transmission charges to the Participants.

The HTSO's costs, including its internal administrative costs and other costs, are passed through to Participants in the Uplift charge.

5. SUMMARY DESCRIPTION OF POWER EXCHANGE CODE

The Power Exchange Code provides for the commercial operations of the System Trading Arrangements. It consists of 5 parts: the General Provisions and Schedules A through D:

Figure 5.1: Contents of Power Exchange Code

GENERAL PROVISIONS	
1.	Definitions
2.	Purpose
3.	Persons and Participants
4.	Market co-ordination and Development Committee
5.	Provision of Information by a Person & HTSO
6.	Role of HTSO
7.	Discontinuing Persons
8.	Termination
9.	Consequences of Default
10.	Currency
11.	Commencement Date and Term
12.	Modification of the Power Exchange Code
13.	Access to Power Exchange Code
14.	Conduct of Settlement and Billing
15.	Publication of a Calendar for Settlement and Billing
16.	Security Cover
17.	Audit of Settlement Software
18.	Audit of the Power Exchange Code
19.	Arbitration
20.	Force Majeure
21.	Liability
22.	Assignment
23.	Notices
24.	Confidentiality
25.	Jurisdiction
SCHEDULE A:	DEFINITIONS
SCHEDULE B:	PROCEDURES
SCHEDULE C:	FORM OF ADDRESS AND CONTACT DETAILS
SCHEDULE D:	SECURITY COVER

5.1. General Provisions

The General Provisions establish the commercial framework within which Persons must operate if they are to trade wholesale Energy in Greece. The General Provisions identify when a Person becomes bound by the terms of the Power Exchange Code and the basis on which a Person's rights under the Power Exchange Code may be revoked. They also establish how much security a Person must provide and the terms on which a Person will be billed and / or paid for their generation / use of Energy. The General Provisions also establish rules governing confidentiality and the resolution of any disputes that may arise under the Power Exchange Code.

5.2. Schedule A

Schedule A to the Power Exchange Code lists and defines the capitalised terms used throughout the Power Exchange Code. Where a definition is taken from the Electricity Law, Operating Code or other document, reference is made to the source document. This provides consistency of terms throughout the suite of documents that make up the STA thereby aiding user readability and understanding.

5.3. Schedule B

Schedule B is the heart of the Power Exchange Code. It specifies the ways in which Participants buy and sell energy through the Power Exchange Code, including: the commercial metering requirements of generators and customers, how meter readings are allocated to Participants and used in the settlement process to determine the quantities of energy bought and sold, the way in which prices are set, the way in which HTSO's costs are recovered from Participants, how invoices and remittances are calculated, how payments and charges are made and it also covers the timing of each activity. Figure 5.2 illustrates the main sections of Schedule B.

Figure5.2: Contents of Schedule B of Power Exchange Code

B. I.	Conventions
B. II.	Responsibility for Energy Metering
B. III.	Other Registration Information and HTSO Responsibilities
B. IV.	Offers, Load and Price Forecasting, Scheduling and Dispatch
B. V.	Special Provisions Relating to International Trade
B. VI.	HTSO Settlement Responsibilities
B. VII.	Settlement Timeline
B. VIII.	Settlement Variables
B. IX.	Determination of Loss Factors
B. X.	Determination of Meter Quantities
B. XI.	Determination of Day-Ahead Quantities
B. XII.	Determination of System Marginal Prices
B. XIII.	Determination of Energy Charges and Energy Payments
B. XIV.	Determination of Constrained-On and Off Payments
B. XV.	Ancillary Services
B. XVI.	Other Charges and Payments
B. XVII.	Determination of Uplift Charges
B. XVIII.	Settlement of Transmission Charges
B. XIX.	Settlement Statements
B. XX.	Invoices
B. XXI.	Compliance
B. XXII.	Suspension of Procedures
B. XXIII.	Information Management

5.4. Schedules C and D

Schedule C sets out the form of a Person's address and contact details. These details are used whenever any notice or communication is given from one Person to another Person in relation to matters concerning the Power Exchange Code.

Schedule D sets out the amount and means by which a Person shall provide security for its financial obligations under the Power Exchange Code. The security can either take the form of a letter of credit or a cash deposit and the amount secured is determined by HTSO on the basis of its estimate of a Person's net value of charges owed by that person to HTSO in respect of the Power Exchange Code over the next 2 calendar months.

FREQUENTLY ASKED QUESTIONS

6. WHAT DOES “NET SETTLEMENT” MEAN?

An important feature of the STA is that it has gross settlement in respect of contracts and net settlement in respect of ownership. In section 4 this was described as meaning:

- All electricity generated or consumed is sold by Generators, bought by Purchasers, and settled by the HTSO.
- The HTSO does not take into account independent contractual arrangements between Participants with regard to its settlement of transactions in the STA.
- The HTSO does, however, consolidate invoices and remittances of Participants owned by the same parent entity. Suppliers, which are both Purchasers and Generators are therefore invoiced or paid for their net financial imbalance. (Each Supplier is treated as a separate Generator and Purchaser in the STA – in this way it is possible for the HTSO to conduct a least cost Dispatch of the full available capacity of Suppliers and not just the capacity net of their final customer load.)

The purpose of this section is to illustrate these principles in more detail. Specifically, it illustrates how a Supplier, being both Purchaser and a Generator, can use the STA serve its load and match imbalances between its generation and consumption. It also illustrates how Participants can enter into bilateral energy contracts with one another within the framework of the STA to buy and sell imbalance energy at predetermined prices, rather than at SMPs, if they so wish.

6.1. Transactions by a Supplier

For purposes of illustration, it is assumed that a simplified situation consists of two Suppliers, A & B. Each Supplier is represented by a Generator and a Purchaser (Generators A & B and Purchasers A & B). The characteristics of these Participants are shown below. (For simplicity, a Dispatch Day is represented by two Dispatch Hours, and the illustrations show the Dispatch and settlement conducted by the HTSO for this simplified Dispatch Day.)

Figure 6.1: Example Situation

Supplier A					Supplier B				
Generator A			Purchaser A		Generator B			Purchaser B	
Comprising:	Capacity (MW):	Production Cost (DRS/MWh)			Comprising:	Capacity (MW):	Production Cost (DRS/MWh)		
Unit A1	200	6,000	Load in Hour 1 (MW):	250	Unit B1	200	5,000	Load in Hour 1 (MW):	250
Unit A2	200	10,000	Load in Hour 2 (MW):	350	Unit B2	200	12,000	Load in Hour 2 (MW):	350

A Supplier must own adequate generating capacity to cover its load. It must also provide long-term confirmation as to necessary reserve capacity and availability of necessary transmission resources. In this example, both Suppliers own more than enough generating capacity for both energy and reserve purposes, and transmission is ignored for simplicity.

6.1.1. Offers and Dispatch

All energy is sold by Generators, bought by Purchasers and settled by the HTSO. The HTSO conducts a least-cost Dispatch of the full available capacity of each Unit so as to meet total load. The Offers received by the HTSO in this example are therefore as follows:

Figure 6.2: Example Offers

Unit ID	MW	Offer Price (DRS/MWh)
A1	200	6,000
A2	200	10,000
B1	200	5,000
B2	200	12,000

The total load is 500 MW in hour 1 and 700 MW in hour 2. The merit order and the production in each hour are thus:

Figure 6.3: Example Merit Order and Dispatch

Unit ID	MW	Offer Price (DRS/MWh)	Output Hour 1	Output Hour 2
B1	200	5,000	200	200
A1	200	6,000	200	200
A2	200	10,000	100	200
B2	200	12,000	0	100
Total	800		500	700

SMP Hr1 (DRS/MWh)	SMP Hr2 (DRS/MWh)
10,000	12,000

The SMP in each hour is set by the marginal Offer cost of supplying an additional MW to the system. The SMP in hour 1 is therefore DRS 10,000/MWh (Unit A2 is the marginal Unit). The SMP in hour 2 is DRS 12,000/MWh (Unit B2 is marginal).

The transactions of each Participant are as follows:

- Generator A sells 300 MW in hour 1 for DRS 3,000,000 and 400 MW in hour 2 for DRS 4,800,000.
- Generator B sells 200 MW in hour 1 for DRS 2,000,000 and 300 MW in hour 2 for DRS 3,600,000.
- Purchasers A and B each buy 250 MW in hour 1 for DRS 2,500,000 and 350 MW in hour 2 for 4,200,000.

Figure 6.4: Example Transactions

	Hour 1			Hour 2			
	MW	Price	DRS (000s)	MW	Price	DRS (000s)	Total DRS (000s)
Gen A Sells	300	10,000	3,000	400	12,000	4,800	7,800
Gen B Sells	200	10,000	2,000	300	12,000	3,600	5,600
Total Sales	500		5,000	700		8,400	13,400
Purch A Buys	250	10,000	2,500	350	12,000	4,200	6,700
Purch B Buys	250	10,000	2,500	350	12,000	4,200	6,700
Total Purchases	500		5,000	700		8,400	13,400

The HTSO consolidates invoices and remittances of Participants owned by the same parent entity and Suppliers are consequently invoiced or paid for their net imbalance. Supplier A is therefore paid DRS 1,100,000 by the HTSO and Supplier B is charged DRS 1,100,000:

Figure 6.5: Example Settlement

Supplier A	Total DRS	Supplier B	Total DRS
Generator A Sales	7,800	Generator B Sales	5,600
less Purchaser A Purchases	6,700	less Purchaser B Purchases	6,700
Net Remittance, Supplier A	1,100	Net Remittance, Supplier B	(1,100)

The practical effect of the net invoice or payment is that Supplier A and Supplier B are paid or charged according to their net generation or consumption in each hour:

Figure 6.6: Example Net Imbalance

Supplier	Hour 1			Hour 2		
	Gen (MW)	Load (MW)	Net Gen (MW)	Gen (MW)	Load (MW)	Net Gen (MW)
A	300	250	50	400	350	50
B	200	250	(50)	300	350	(50)
Total	500	500	0	700	700	0

Supplier A is paid DRS 1,100,000 (50*10,000 + 50*12,000) by the HTSO and Supplier B is charged DRS 1,100,000 (50*10,000 + 50*12,000).

The practical effect of this least-cost Dispatch and net settlement with respect to ownership is that to the extent a Supplier can meet its customers' energy requirements from purchases through the STA more cheaply than by producing itself, it will do so. The transactions for obtaining the necessary imbalance energy are embedded in the trading arrangements. In this example, Supplier B purchased energy in both hours from Supplier A, and in doing so lowered the total system cost from what it would have been if it had generated sufficient energy to cover all its own load.

7. HOW DO BILATERAL CONTRACTS WORK?

SMPs fluctuate according to market conditions. Participants, if they desire, can make bilateral contracts between one another to "lock-in" the price at which imbalance energy is bought and sold, so as to remove the financial uncertainty of paying or being paid the SMP.

For example, in the preceding illustration Supplier B buys 50 MW in each hour of the illustrative day at the SMP. To the extent the SMP rises or falls, Supplier B's costs rise and fall. Yet Supplier B might have little influence over the market conditions that cause movements in the SMP. (Its costs *are* capped, because Suppliers are obliged to own enough capacity to cover their load – Supplier B's costs can never exceed its own production costs of DRS 12,000/ MWh from Unit B2.) But Supplier B may wish to enter into a contract with Supplier A, or perhaps an independent Generator that is not a Supplier, to lock-in its cost for imbalance energy at a lower price.

The form of contract that Participants can enter into for this purpose is a Contract For Differences (CFD). A CFD is a financial contract between the parties to the bilateral transaction and is independent from the HTSO. A CFD has a strike price and a MW quantity. In its most simple form it specifies that:

- when the SMP is higher than the strike price, the Generator pays the Purchaser the SMP minus the strike price, multiplied by the CFD MW quantity, for that hour; and
- when the SMP is lower than the strike price, the Purchaser pays the Generator the strike price minus the SMP, multiplied by the CFD MW quantity, for that hour.

The financial effect of a CFD, therefore, is that both the Generator and the Purchaser receive a guaranteed net price – the strike price – at which they respectively sell and buy the CFD MW quantity of imbalance energy.

The existence of a CFD does not change the way the Generator offers its capacity to the HTSO, or the way in which the HTSO operates the system. Furthermore, the settlement of CFD payments is made independently of the HTSO, between the Participants concerned. Consequently, since executing bilateral transactions in the form of CFDs does not require any special action from the HTSO in addition to its regular responsibilities as system operator and market operator, there are no special rules regarding these contracts in the STA. The HTSO does not need to be aware of their existence.

8. HOW DOES HTSO ENSURE ADEQUATE INSTALLED CAPACITY?

An important element in any liberalised electricity market is the means of ensuring that there is sufficient installed capacity to meet demands. In Greece, the Greek Electricity Law imposes certain obligations on Suppliers which are designed to ensure the adequacy of installed capacity.

8.1. Issuance of Electricity Supply Authorisations

Electricity Supply Authorisations are issued by the Minister of Development, following an opinion from the Energy Regulatory Authority (RAE). The Greek Electricity Law specifies that one condition of obtaining an Electricity Supply Authorisation is that the candidate Supplier owns adequate generating capacity and has satisfactory long-term arrangements in place for the necessary level of reserve.

The methods by which the RAE forms its opinions on the authorisation of individual candidate Suppliers are outside of the STA. However, the Codes of the System Trading Arrangements assume that in order for a Supplier to be recommended by the RAE and subsequently to be authorised to serve load totalling X MW, the RAE has satisfied itself that, in addition to other obligations:

- the Supplier owns Units with operational net capacity of at least X MW;
- the Supplier also owns, or has contracted on a firm basis, further operational net capacity of aX MW, where a is a percentage installed reserve requirement specified by the HTSO and approved by the RAE, and is the same value for all Suppliers, regardless of ownership;
- all of the capacity in question is located in accordance with the Greek Electricity Law and all necessary confirmation as to the availability of transmission capacity has been provided, including the ownership by the Supplier of rights to use interconnector capacity into Greece for the amount of the operational net capacity which is located outside of Greece; and
- the HTSO has conducted or monitored operational tests or other tests on the Units involved to confirm that the $(1+a)X$ MW of net capacity is operable and meets the technical requirements for participation in the STA.

It is the responsibility of the RAE to keep the HTSO informed of the terms of each approved Electricity Supply Authorisation, including any changes over time, and of the obligations imposed under each.

8.2. Compliance with Electricity Supply Authorisations

The Codes specify that once a Supplier is authorised, it must inform the HTSO and the RAE of any subsequent change in the operational capability or ownership of its net capacity. The Codes also specify that the HTSO will conduct on-going studies and operational tests over time to confirm that Suppliers continue to provide the level of operational net capacity that complies with their Electricity Supply Authorisations.

The methods by which Suppliers may obtain rights to use interconnector capacity into Greece are outside of the STA. However the Codes require that the HTSO confirm on an on-going basis that Suppliers hold the necessary rights in respect of Units in foreign countries before an Offer from such a Unit is accepted in the STA.

The Codes also require that one or more Suppliers take responsibility for the total load of each customer. On an on-going basis it is a responsibility of the HTSO to confirm that the metered aggregate MW load of the Supplier's customers complies with its Electricity Supply Authorisation in any hour.

It is also the responsibility of the HTSO to record the details of the Suppliers' other obligations under their Authorisations, including their Electricity Generation Authorisations where applicable, and to monitor their compliance with these on an on-going basis.

It is not the responsibility of the HTSO to apply penalties or other sanctions on Suppliers that are not compliant with respect to their Authorisations. The HTSO is responsible for reporting the nature of any non-compliance to the RAE and it is an on-going responsibility of the RAE to determine the consequences to the Suppliers concerned on a case-by-case basis. Consequently, penalties for non-compliance in respect of Electricity Supply Authorisations are not contained in the STA.[7]

[7] The HTSO does, however, require that the authorised capacity runs, if called upon and given a reasonable and pre-determined recall period, in the event of System Emergency Conditions or System Critical Conditions. This requirement and the consequence for non-compliance in these situations are described in the Codes.

9. HOW DOES HTSO ENSURE ADEQUATE AVAILABLE CAPACITY?

It is the HTSO's responsibility to ensure that adequate generating capacity is available so as to meet its system reliability requirements. The System Trading Arrangements are designed to give the HTSO the mechanisms it needs so that it can arrange this necessary capacity and the System Trading Arrangements are also designed to encourage Participants to have incentives consistent with the HTSO's responsibilities in this regard.

9.1. HTSO Mechanisms

The HTSO has several processes with which it can collectively arrange adequate available capacity, including:

- the day-ahead scheduling process;
- the process of contracting for Ancillary Services; and
- the generator outage co-ordination process.

The day-ahead scheduling process occurs once a day, seven days a week, to produce forecast generation schedules for both energy and Ancillary Services and to forecast SMPs for each hour of the following day, on the basis of the Offers received. Having made Offers day-ahead, Units that are in Greece and are scheduled day-ahead in the "constrained schedule" are committed to providing their offered capacity, in accordance with their offered price and quantity parameter submissions and within the limits of their technical parameters specified in their Registered Information, if called upon by the HTSO to run in the Dispatch Day. The HTSO thus relies on Units scheduled day-ahead to be available for the following day, and schedules sufficient capacity, including Operating Reserve, so as to factor in Load forecast error, forced outages, and other uncertainties that may occur on the day.

On a longer-term basis, the HTSO can enter into Ancillary Services contracts to ensure that sufficient Operating Reserve is available in the day-ahead scheduling process. Ancillary Services contracts can specify minimum availability conditions and other conditions such that the HTSO is able to arrange for available capacity well before the day before the Dispatch Day.

The procedures to be followed by the HTSO with regard to day-ahead scheduling and the use of Ancillary Services contracts are specified in the Operating Code and the Ancillary Services contracts themselves, not the Power Exchange Code. Paragraph 21 of Schedule B of the Power Exchange Code states:

21. Scheduling Procedure

The procedure to be followed by **HTSO** in the scheduling of **Units**, including the scheduling of **Special Units**, **Indigenous Fuelled Units**, **Interconnectors** and **Ancillary Services** providers and in the production of **Generation Schedules**, shall be in accordance with the **Operating Code**, the applicable **Interconnection Agreements,** the applicable **Ancillary Services** agreements, and any other applicable requirements.

In addition, the HTSO may utilise other longer-term provisions, such as the provisions for generator outage co-ordination scheduling provided for in the Operating Code, in order to assist the organisation of adequate available capacity over the longer-term.

9.2. Participant Incentives

Perhaps the most important mechanism in the STA to ensure adequate available capacity is the manner in which the SMP is determined. The SMP is high when there is a shortage of capacity and is low when there is a surplus. In this way, the SMP encourages Participants to have incentives consistent with the HTSO's responsibilities: if the SMP is high, Generators will have incentives to make their Units available because they can profitably sell their output, and Suppliers/ Eligible Customers will have incentives to reduce Load if at all possible.

In the event of a System Emergency Condition, or risk of a a System Emergency Condition, these incentives may be very strong, because the SMP can be set to a very high level. From paragraph 51 of Schedule B:

51. Administered Prices in System Emergency Conditions

1. In the event of a **System Emergency Condition** in which involuntary **Load** shedding occurs on a widespread basis and there is no **Capacity Adequacy**, **HTSO** shall set the **SMP** equal to an **Administered Price** that equals the **Value of Lost Load**.

2. **HTSO** shall set the **Value of Lost Load** at a level approved by the **Minister of Development. HTSO** shall publish the **Value of Lost Load** on the **HTSO Web-Site** and notify **Participants** of any change to the **Value of Lost Load**.

Conversely, if the SMP is low, Generators will take this as a signal as being a good time to schedule an outage of their Units, if repairs or other circumstances dictate. Low prices are a signal to Suppliers and Eligible Customers of surplus capacity and thus are a signal to them that it is a good time to increase consumption if they are at all flexible.

10. HOW ARE SMPS DETERMINED?

The System Marginal Price (SMP) in each Dispatch Hour reflects the marginal cost of meeting actual demand on the system given actual generation availability in that hour. The SMP is calculated ex-post, ie, after the Dispatch has occurred, in a separate calculation. SMPs are calculated based on the Offers submitted by Generators, actual Unit availability, and actual Load. In the event of suspension of the STA, SMPs are set to an Administered Price.

SMPs are calculated after the Dispatch has been completed, and after Meter Quantity data has been determined. They are calculated on the Calculation Day, the day five days after the Dispatch Day.

The rules for the determination of SMPs are specified in section XII of Schedule B of the Power Exchange Code (paragraphs 46 to 53). Paragraph 48 is the principal paragraph, specifying the methodologies and principles that Pricing Software must comply with.

10.1. Calculation of SMP

The main provisions of paragraph 48 are as follows:

SMPs are computed as a result of a calculation of an "unconstrained" schedule of the system using actual Unit Offer parameters (as assumed in the Dispatch) as inputs. The level of load assumed is the total MWh of actual Meter Quantity load determined for that hour over the interconnected transmission system.

The calculation of the ex-post unconstrained schedule and the determination of SMP from this schedule are made in the same way the forecast unconstrained schedule and forecast SMP are determined day-ahead (but the calculations are independent). In producing the ex-post unconstrained schedule the HTSO schedules Unit Offers so as to minimise the offered cost of total load, including losses, taking into account the following factors:

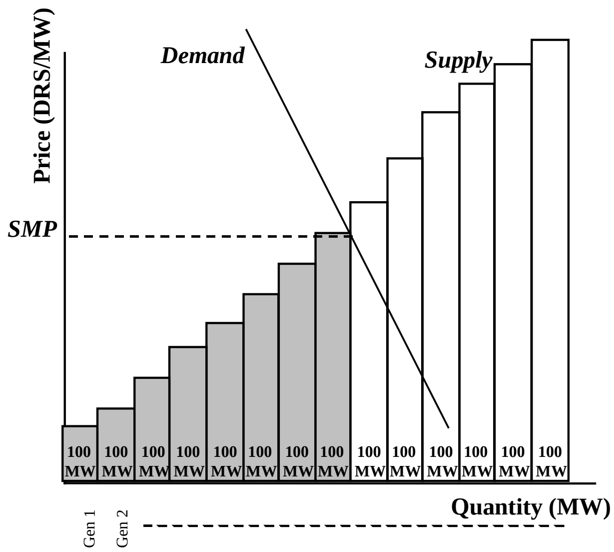
- the price and quantity parameters of all Offers received in respect of Units in Greece;
- the actual maximum net availability of each Unit in Greece in the Dispatch Hour concerned;
- exclusive dispatch arrangements for Special Units and Indigenous Fuelled Units;
- Operating Reserve requirements;
- transmission system losses, incorporating any regional differences;
- the actual flows on the interconnectors; and

- the technical parameters of Units as set out in their Registered Information (or otherwise advised).

The HTSO does not take into account transmission constraints in the calculation of the ex-post unconstrained schedule.

Conceptually, the SMP in each Dispatch Hour is set as being equal to the point at which the supply curve for energy meets the demand curve for energy:

Figure 10.1: Determination of SMP



More specifically, the SMP in each Dispatch Hour is set as being equal to the Offer price of the marginal Unit dispatched to meet demand in the ex-post schedule, given the level of output for which the Unit is dispatched, and adjusted for the marginal rate of transmission system losses between the Unit and the Reference Node. The marginal Unit is that Unit which would increase output if total demand at the Reference Node increased by a marginal amount. Inflexible Units cannot therefore set the SMP if they are constrained by their inflexibility (such as a must-run condition) in a given hour.

10.2. Administered Prices

The normal method of Dispatch and / or the calculation of SMPs can be suspended, and thus “the STA can be suspended”, when:

- there is a System Emergency Condition, which can include certain force majeure conditions such as war or earthquakes; or
- when there are important failures that do not allow the HTSO to get the information it needs to Dispatch the system according to the Codes.

In the event of STA suspension, the HTSO will set Administered Prices. The Administered Prices will be determined in relation to the prices (either the forecast SMP or the actual SMP, depending on which type of price is relevant) in the time period(s) immediately preceding and/or following the suspension, and/or by the use of estimated data. In the event of a System Emergency Condition in which involuntary load shedding occurs on a widespread basis, the Administered Price will be set equal to the VOLL (the Value of Lost Load). Under no circumstance will an Administered Price be set higher than the VOLL.

10.3. Forecast SMPs

Forecast SMPs are calculated in the day-ahead scheduling process. Forecast SMPs are calculated using the same methodologies and principles as specified above, and are calculated using the same software as ex-post SMPs. Forecast SMPs are, of course, determined with forecast data values for Load, generation availability and other factors. Paragraph 20 of Schedule B specifies the rules for calculating and using forecast SMPs.

The schedule used for calculating forecast SMPs is, like the schedule for ex-post SMPs, an "unconstrained" one. This means that it does not take into account transmission constraints. In principle, this is the only difference between the "unconstrained" schedule and the "constrained" schedule referred to above in section 9 of this document (and referred to as the "Generation Schedule" in the Operating Code). In practice, there may be other minor differences in the way the schedules are calculated.

11. HOW DO CONSTRAINED-ON/OFF PAYMENTS WORK?

Having made Offers day-ahead, Units that are in Greece and are scheduled day-ahead (in the “constrained schedule”) are committed to providing their offered capacity, in accordance with their offered price and quantity parameter submissions and within the limits of their technical parameters specified in their Registered Information, if called upon by the HTSO to run in the Dispatch Day. In return, the HTSO guarantees that flexible Units in Greece at least recover all their costs, as represented by their Offers, over the course of the Dispatch Day.

In general, during any hour in which a Unit is dispatched, the SMP shall at least equal its Offer Price. Accordingly, all available Units whose Offer price is below the SMP shall be fully dispatched to run and no available Units whose Offer price is above the SMP shall be dispatched to run.

However, there might be occasions when the Dispatch is not consistent with the SMP, meaning that given the SMP, a Generator might be better off producing a different amount than it was instructed to produce by the HTSO. This situation is not typical, but can arise because of transmission constraints, or other reasons.

In these situations, additional Constrained-On Payments and Constrained-Off Payments are made to Generators. These payments are evaluated on an hourly and daily basis. The exception to this rule is that no additional payments are made in respect of Units whose Registered Information or Offer is changed during the course of a Dispatch Day, Units who fail to comply with Dispatch Instructions or for whom metering data has not been supplied, Units in foreign countries and Special Units, and no additional payments are made in respect of the Special Participant.

11.1. Constrained-Off Payments

When the instructed output of a Unit in Greece in a Dispatch Hour is below that consistent with the SMP for that hour, it is paid a Constrained-Off Payment. This payment equals the difference between the SMP and the Unit’s Offer price, multiplied by the MW difference between its instructed output and the output level that would be consistent with the SMP. (However, since the Offer price may vary over the range of offered capacity of a Unit, this description is somewhat of a simplification. Section 11.3 illustrates the exact rules in the Power Exchange Code.)

The output level that is consistent with the SMP in the case of constrained-off Units is the maximum actual availability of the Unit in the Dispatch Hour concerned. Generally this is the maximum offered capacity of the Unit. However, if a Unit is held tightly against its maximum ramp-up rate, or otherwise not able to increase output beyond that instructed during a Dispatch Hour because of an operating constraint *it* has specified, then the actual output level *is* consistent with the SMP, and the Unit does not receive a Constrained-Off payment in that hour. Paragraph 61 of Schedule B of the Power Exchange Code defines the exact rules for how this maximum is determined.

11.2. Constrained-On Payments

When the instructed output of a Unit in Greece in a Dispatch Hour is above that consistent with the SMP for that hour, it is paid a Constrained-On Payment. This payment equals the difference between its Offer price and the SMP, multiplied by its instructed MW output in that Dispatch Hour. (Again, since the Offer price may vary over the range of offered capacity of a Unit, this description is somewhat of a simplification. Section 11.3 illustrates the exact rules in the Power Exchange Code.)

The output level that is consistent with the SMP in the case of constrained-on Units is the minimum actual availability of the Unit in the Dispatch Hour concerned. Generally this is the minimum offered capacity of the Unit. Consequently, a Unit constrained from producing less because of a minimum output level constraint during a Dispatch Hour does not receive a Constrained-On Payment in that hour.[8] In addition, a Unit constrained from producing less because of its maximum ramp-down rate during a Dispatch Hour does not receive a Constrained-On Payment in that hour. Paragraph 65 of Schedule B of the Power Exchange Code defines the exact rules for how this minimum is determined.

Having evaluated all Constrained-On Payments and Constrained-Off Payments over the Dispatch Day, if a Unit in Greece still didn't recover its costs, as represented by its Offer, and it was instructed by the HTSO to start-up and synchronise for the Dispatch Day, then it is given an additional constrained-on payment so that all its costs are recovered. This means that a Unit which is instructed to start, and that does not fall into one of the categories of exceptions above, is guaranteed to at least recover its costs over the day, even it was inflexible during some hours.

11.3. Illustration

The remainder of this section illustrates in more detail, with diagrams and with reference to the rules in the Power Exchange Code, how the Constrained-On Payments and Constrained-Off Payments are calculated.

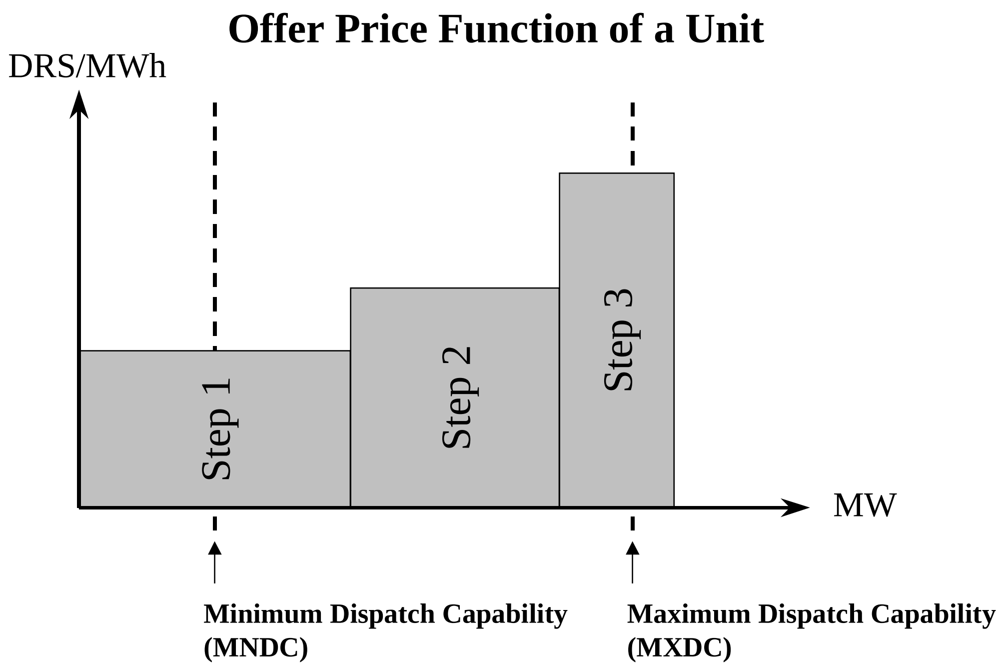
8 An exception to this rule is in the case of a Unit being constrained-on by the HTSO because it is an Indigenous Fuelled Unit.

Constrained-On Payments and Constrained-Off Payments are calculated pursuant to section XIV of Schedule B of the Power Exchange Code. Paragraph 60 of Schedule B specifies that the payments are calculated hourly:

> **60. Timing of Calculation of Constrained-On and Off Payments**
>
> On the **Calculation Day** in respect of a **Dispatch Day**, **HTSO** shall calculate **Constrained-On Payments** and **Constrained-Off Payments** in respect of each **Unit** in Greece, for each **Dispatch Hour** of the **Dispatch Day**.

The rules for the calculation of Constrained-On Payments and Constrained-Off Payments rely on the 3-step form of the Offer function, illustrated in the following diagram:

Figure 11.1



Paragraphs 61 and 65 of Schedule B specify how the minimum dispatch capability and maximum dispatch capability of a Unit in a Dispatch Hour, illustrated in this diagram, are calculated.

In order to calculate Constrained-Off Payments for a Unit, it is necessary to first calculate the "in-merit" capability of each step of the Unit's Offer price function in a Dispatch Hour. Paragraph 62 of Schedule B sets out how this is done. Paragraph 62.2 specifies the formula for determining how much of the first step of a Unit's Offer price function is "in merit".

62.2 The in-merit capability of the first step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations:

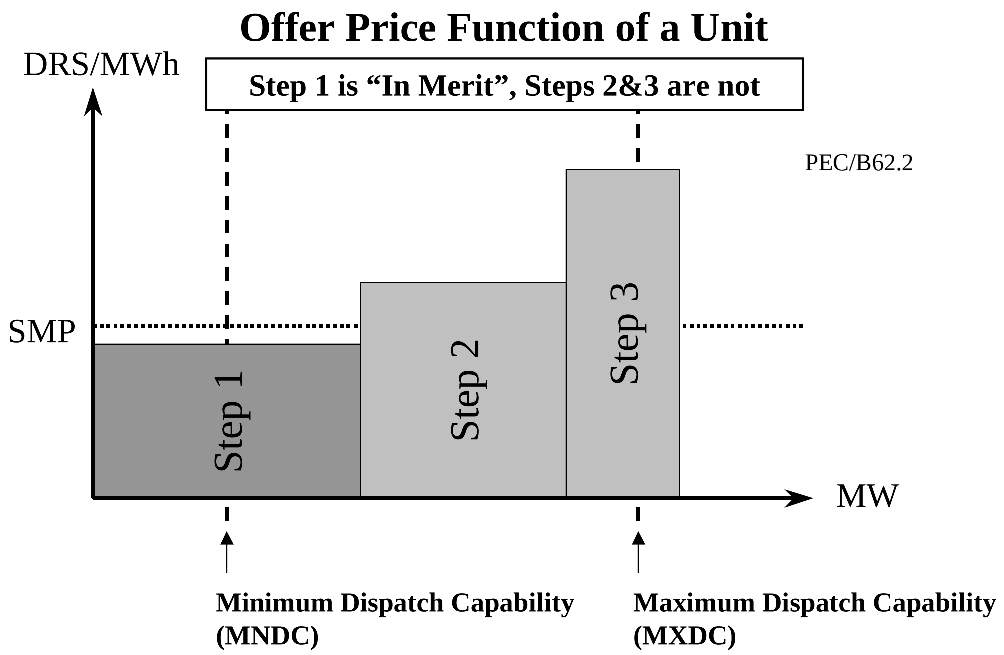
$$
\begin{aligned}
&If\ (OP_{ud1} \leq SMP_t)\\
&then\\
&IMC_{ut1} = Min(OQ_{ut1}, MXDC_{ut})\\
&otherwise\\
&IMC_{ut1} = 0
\end{aligned}
$$

where *t* is a **Dispatch Hour** that falls within **Dispatch Day** *d*; and

where $MXDC_{ut}$ is the maximum dispatch capability of **Unit** *u* in **Dispatch Hour** *t*, pursuant to PEC / B61.

In the following illustration, all of the Offered capacity of step 1 of the Offer price function is "in merit" because the Offered price of the first step is less than SMP:

Figure 11.2



Paragraph 62.3 of Schedule B specifies the formula for determining how much of the second step of a Unit's Offer price function is "in merit".

62.3 The in-merit capability of the second step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations:

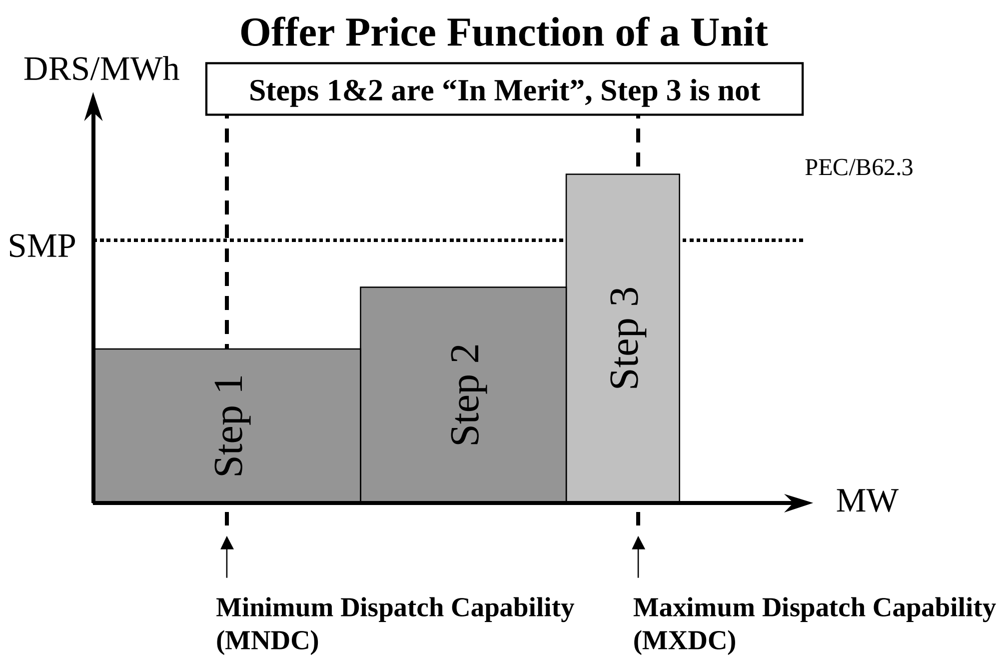
$$If\ (OP_{ud2} \leq SMP)$$
$$then$$
$$IMC_{ut2} = Min(OQ_{ut2}, MXDC_{ut} - IMC_{ut1})$$
$$otherwise$$
$$IMC_{ut2} = 0$$

where t is a **Dispatch Hour** that falls within **Dispatch Day** d; and

where $MXDC_{ut}$ is the maximum dispatch capability of **Unit** u in **Dispatch Hour** t, pursuant to PEC / B**Error! Reference source not found.**.

In the following illustration, all of the Offered capacity of step 2 of the Offer price function is "in merit" because the Offered price of step 2 is less than SMP:

Figure 11.3



Paragraph 62.4 of Schedule B specifies the formula for determining how much of the third step of a Unit's Offer price function is "in merit".

62.4 The in-merit capability of the third step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations:

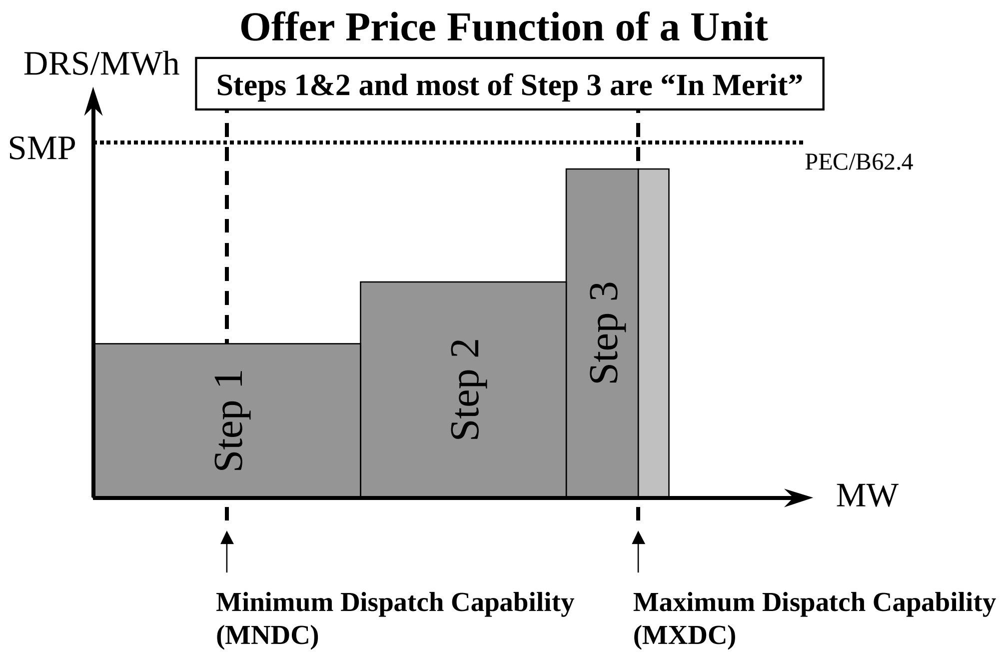
$$If\ (OP_{ud3} \le SMP_t)$$
$$then$$
$$IMC_{ut3} = Min(OQ_{ut3}, MXDC_{ut} - IMC_{ut1} - IMC_{ut2})$$
$$otherwise$$
$$IMC_{ut3} = 0$$

where *t* is a **Dispatch Hour** that falls within **Dispatch Day** *d*; and

where $MXDC_{ut}$ is the maximum dispatch capability of **Unit** *u* in **Dispatch Hour** *t*, pursuant to PEC / B61.

In the following illustration, about three-quarters of the Offered capacity of step 3 of the Offer price function is "in merit" because, although the Offered Price of step 3 is less than SMP, some of the Offered capacity of step 3 exceeds the maximum dispatch capability of the Unit in the Dispatch Hour:

Figure 11.4



In order to calculate Constrained-Off Payments for a Unit, it is necessary to also calculate the "constrained-off capability" of each step of the Unit's Offer price function in a Dispatch Hour. Paragraph 63 of Schedule B sets out how this is done. Paragraph 63.2 specifies the formula for determining the constrained-off capability of the first step.

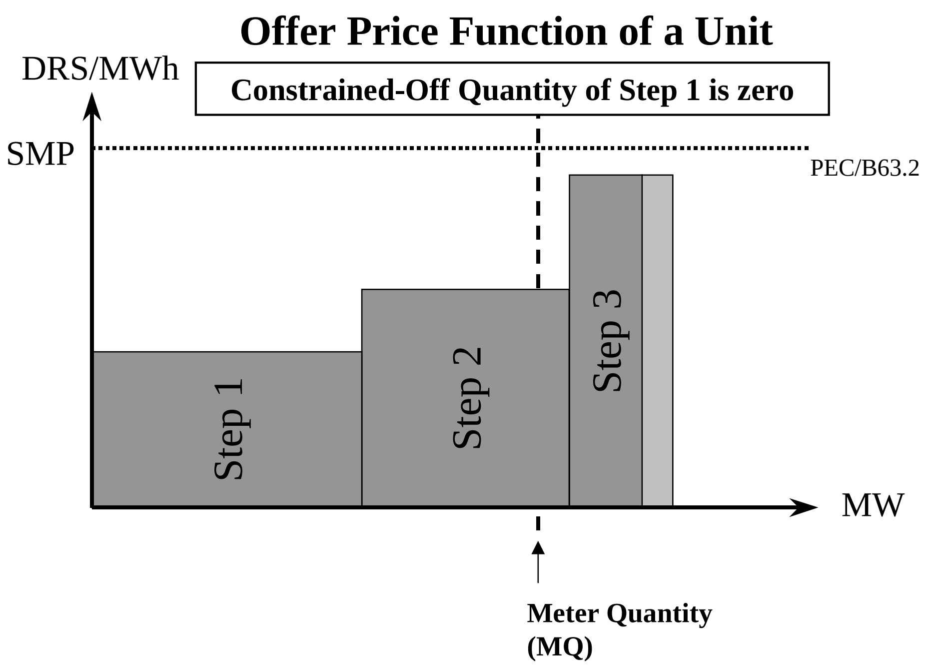
63.2 The constrained-off capability of the first step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equation:

$$COFC_{ut1} = Max(IMC_{ut1} - MQ_{ut}, 0)$$

Meter Quantities are used in this formula and in subsequent formulae (as opposed to Dispatch Instruction quantities, which may be regarded by some as more intuitive). However, if Meter Quantities vary too much from Dispatch Instruction quantities, Units are subject to being denied any Constrained-Off Payments or Constrained-On Payments in accordance with paragraph 69 and non-compliance penalty provisions provided for elsewhere in the Power Exchange Code will apply.

In the following illustration, none of the Offered capacity of step 1 of the Offer price function is constrained-off because the Meter Quantity is greater than the in-merit capability of the first step:

Figure 11.5



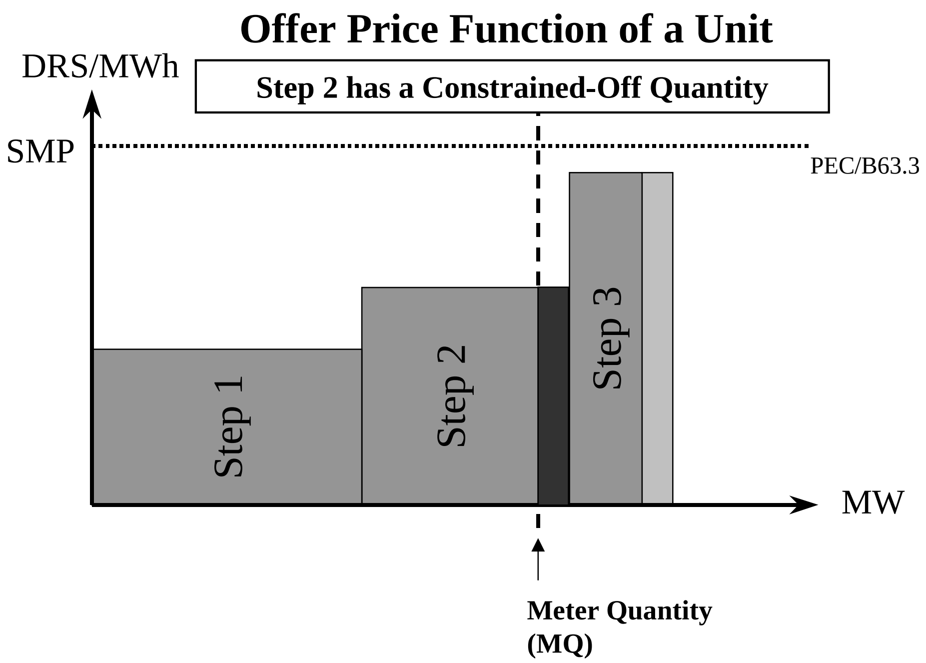
Paragraph 63.3 specifies the formula for determining the constrained-off capability of the second step.

63.3 The constrained-off capability of the second step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equation:

$$COFC_{ut2} = Max(IMC_{ut1} + IMC_{ut2} - MQ_{ut} - COFC_{ut1}, 0)$$

In the following illustration, about 20% of the Offered capacity of step 2 of the Offer price function is constrained-off because the Meter Quantity is less than the in-merit capability of the first and second steps:

Figure 11.6



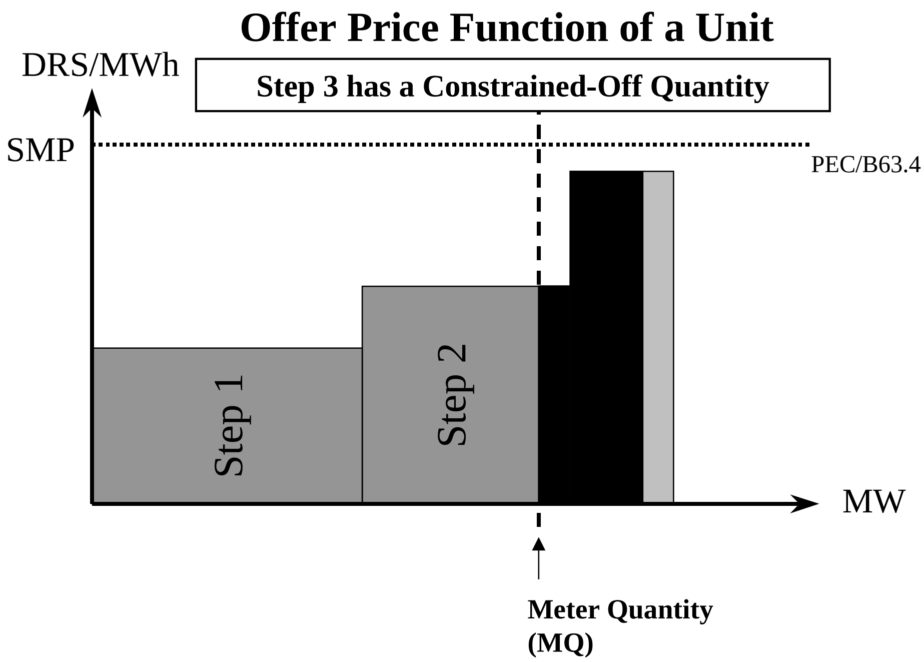
Paragraph 63.4 specifies the formula for determining the constrained-off capability of the third step.

63.4 The constrained-off capability of the third step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equation:

$$COFC_{ut3} = Max(IMC_{ut1} + IMC_{ut2} + IMC_{ut3} - MQ_{uit} - COFC_{ut1} - COFC_{ut2}, 0)$$

In the following illustration, about three-quarters of the Offered capacity of step 3 of the Offer price function is constrained-off because the Meter Quantity is less than (the in-merit capability of each of the steps less the constrained-off capability of step 2):

Figure 11.7



Paragraph 64 specifies the formula for determining the Constrained-Off Payment for the Unit, and all other Units owned by the corresponding Generator, in the Dispatch Hour.

64. Determination of Constrained-Off Payments of a Unit

Except as provided in PEC/B69, the **Constrained-Off Payment** in respect of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equation:

$$COFP_{gt} = \sum_{u \in g} \sum_{s=1}^{3} Max(0, SMP_t(1 + TLFG_{it}) - OP_{uds})COFC_{uts}$$

where t is a **Dispatch Hour** that falls within **Dispatch Day** d;

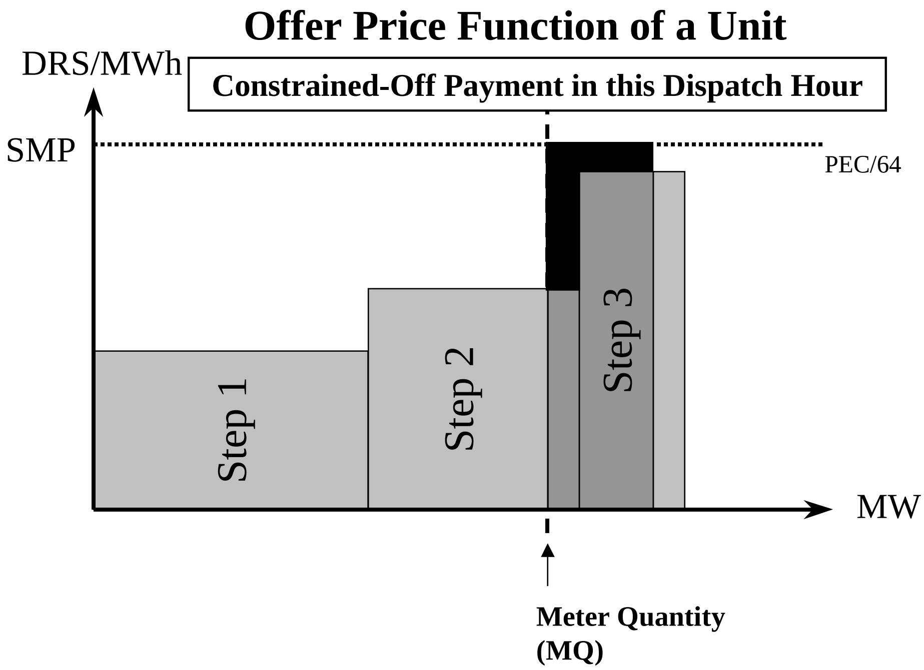
where **Unit** u is located at **Node** i;

where $u \in g$ signifies that the summation is made for each **Unit** u that, according to its **Registered Information**, is owned by **Participant Generator** g; and

where **HTSO**, in order to fairly account for the effect of **Distribution Loss Factors** of **Distribution-Embedded Units**, may, in accordance with the terms of its authorisation, appropriately adjust the equation in respect of a **Distribution-Embedded Unit** so as to account for a **Distribution Loss Factor**.

In the following illustration, Constrained-Off Payments equal to the black shaded area are made in respect of the Unit for the Dispatch Hour. (In this simplified illustration, the effect of Transmission Loss Factors has been ignored.)

Figure 11.8



In order to calculate Constrained-On Payments for a Unit, it is necessary to calculate the "constrained-on capability" of each step of the Unit's Offer price function in a Dispatch Hour. Paragraph 66 of Schedule B sets out how this is done. Paragraph 66.2 specifies the formula for determining how much of the third step of a Unit's Offer price function is constrained-on.

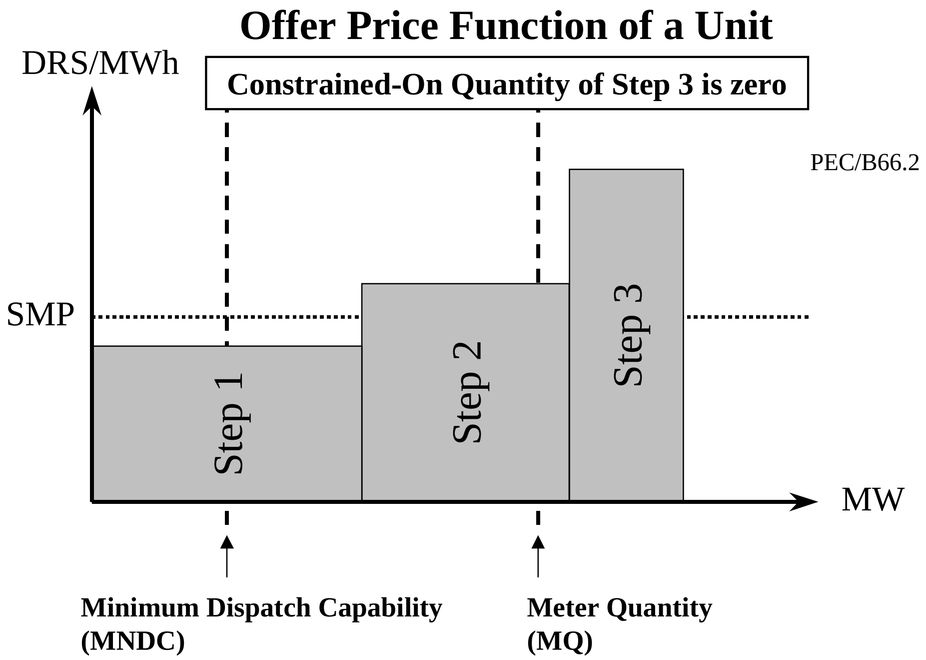
66.2. The constrained-on capability of the third step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations

$$If\,(OP_{ud3} > SMP_t)\,and\,(MQ_{ut} > OQ_{ut1} + OQ_{ut2})$$
$$then$$
$$CONC_{ut3} = Min(Max(MQ_{ut} - MNDC_{ut}, 0), Max(MQ_{ut} - OQ_{ut2} - OQ_{ut1}, 0))$$
$$otherwise$$
$$CONC_{ut3} = 0$$

where $MNDC_{ut}$ is the minimum dispatch capability of **Unit** *u* in **Dispatch Hour** *t*, pursuant to PEC / B65.

In the following illustration, none of the Offered capacity of step 3 of the Offer price function is constrained-on because the Meter Quantity is not greater than the Offered quantity of the first and second steps:

Figure 11.9



Paragraph 66.3 specifies the formula for determining how much of the second step of a Unit's Offer price function is constrained-on.

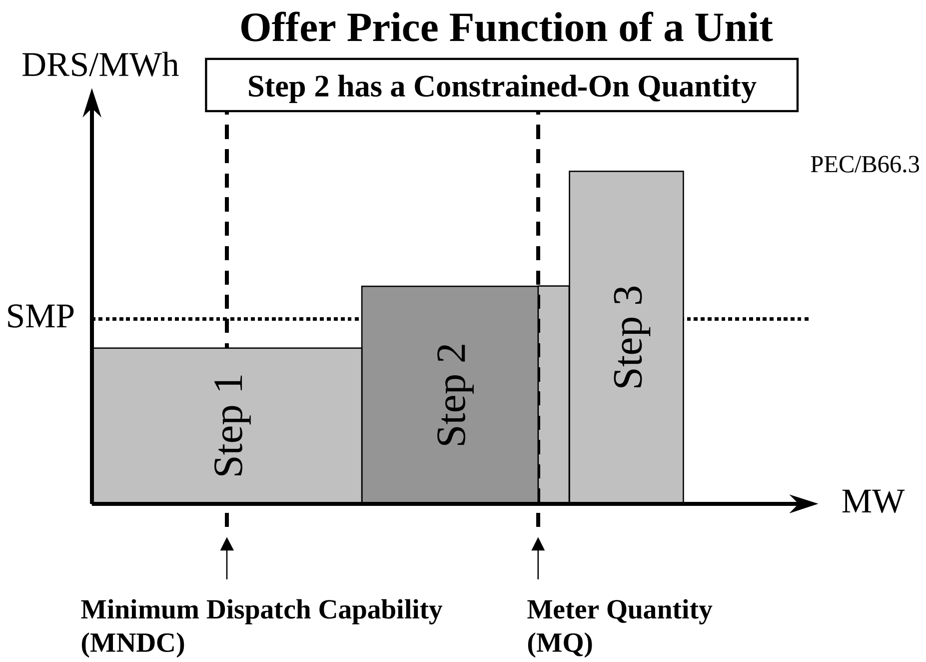
66.3 The constrained-on capability of the second step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations:

$$\begin{aligned}
&If\,(OP_{ud2} > SMP_t)\,and\,(MQ_{ut} > OQ_{ut1})\\
&then\\
&CONC_{ut2} = Min(Max(MQ_{ut} - MNDC_{ut} - CONC_{ut3}, 0), Max(MQ_{ut} - OQ_{ut1} - CONC_{ut3}, 0))\\
&otherwise\\
&CONC_{ut2} = 0
\end{aligned}$$

where $MNDC_{ut}$ is the minimum dispatch capability of **Unit** u in **Dispatch Hour** t, pursuant to PEC / B65.

In the following illustration, about 80% of the Offered capacity of step 2 of the Offer price function is constrained-on because the SMP is less than the Offered price of the second step, and the Meter Quantity is greater than the Offered capacity of the first step:

Figure 11.10



Paragraph 66.4 specifies the formula for determining how much of the first step of a Unit's Offer price function is constrained-on.

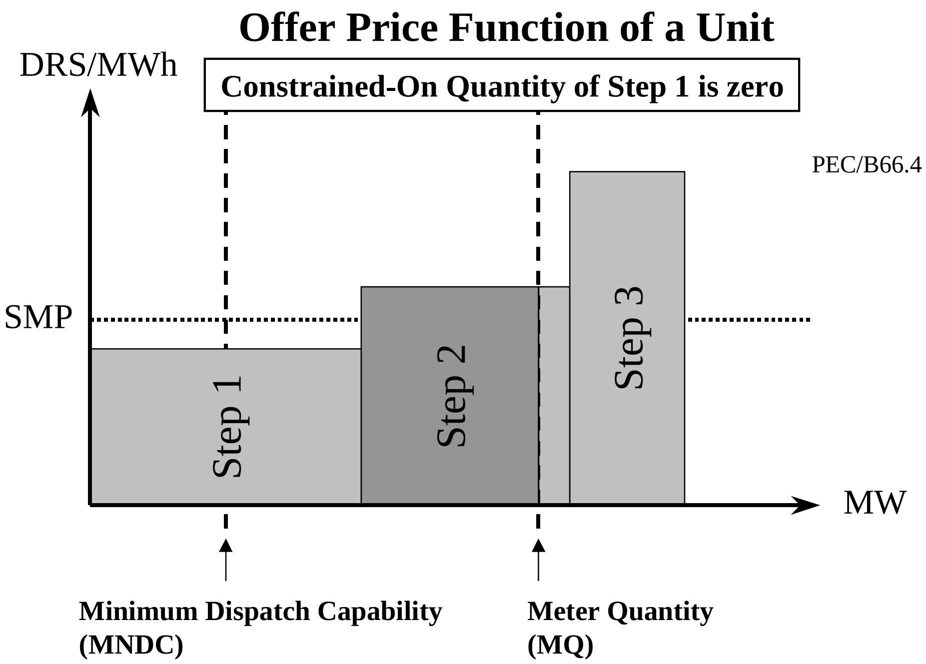
66.4 The constrained-on capability of the first step of the **Offer Price Function** of a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equations:

$$If\,(OP_{ud1} > SMP_t)\,and\,(MQ_{ut} > 0)$$
$$then$$
$$CONC_{ut1} = Max(MQ_{ut} - MNDC_{ut} - CONC_{ut3} - CONC_{ut2}, 0)$$
$$otherwise$$
$$CONC_{ut1} = 0$$

where $MNDC_{ut}$ is the minimum dispatch capability of **Unit** u in **Dispatch Hour** t, pursuant to PEC / B65.

In the following illustration, none of the Offered capacity of step 1 of the Offer price function is constrained-on because the SMP is greater than the Offered price of the first step:

Figure 11.11



Paragraph 67 specifies the formula for determining the Constrained-On Payment for the Unit, and all other Units owned by the corresponding Generator, in the Dispatch Hour.

67. Determination of Constrained-On Payments of a Unit

Except as provided in PEC/B69 and except if a **Constrained-Off Payment** is payable in respect of a **Unit** in a **Dispatch Hour** pursuant to PEC/B64, then a **Constrained-On Payment** in respect if a **Unit** in a **Dispatch Hour** shall be calculated in accordance with the following equation:

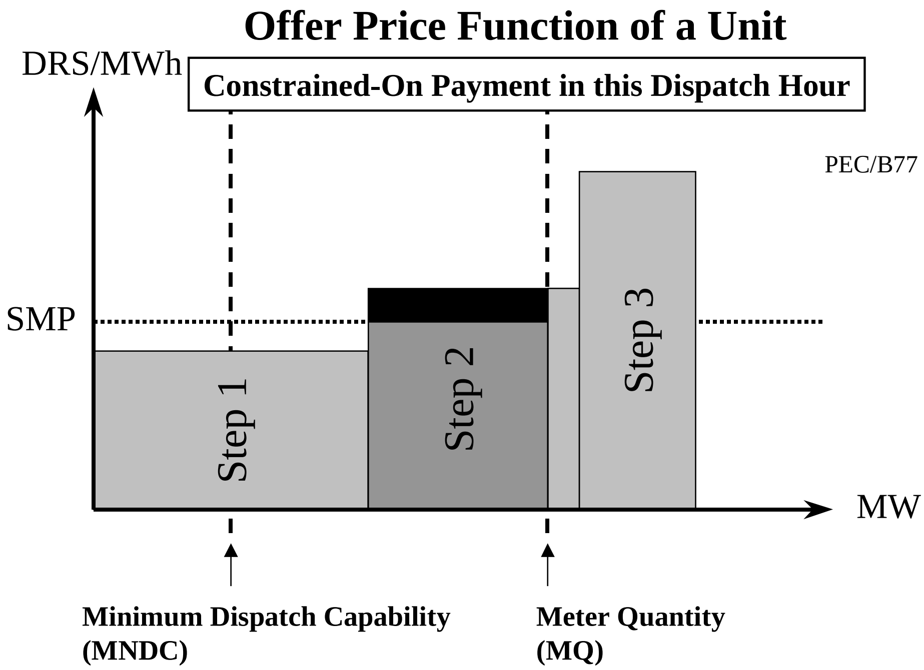
$$CONP_{gt} = \sum_{u \in g} \sum_{s=1}^{3} Max(0, OP_{uds} - SMP_t(1+TLFG_{it}))CONC_{uts}$$

where t is a **Dispatch Hour** that falls within **Dispatch Day** d;
where **Unit** u is located at **Node** i;
where $u \in g$ signifies that the summation is made for each **Unit** u that, according to its **Registered Information**, is owned by **Participant Generator** g; and

where **HTSO**, in order to fairly account for the effect of **Distribution Loss Factors** of **Distribution-Embedded Units**, may, in accordance with the terms of its authorisation, appropriately adjust the equation in respect of a **Distribution-Embedded Unit** so as to account for a **Distribution Loss Factor**.

In the following illustration, Constrained-On Payments equal to the black shaded area are made in respect of the Unit for the Dispatch Hour. (In this simplified illustration, the effect of Transmission Loss Factors has been ignored.)

Figure 11.12



Paragraph 69 provides for additional Constrained-On Payments if:

- the Unit in question was instructed by the HTSO to start-up and synchronise; and
- the payments for energy plus any Constrained-On Payments and Constrained-Off Payments (above) do not cover the Offered costs represented in the 3-step price function *plus* the Offered start-up price.

Paragraph 68 imposes additional restrictions:

68. Additional Constrained-On Payments

1. Except as provided in PEC / B69, **HTSO** shall make an additional **Constrained-On Payment** to a **Participant Generator** in respect of a **Unit** if:

   (a) the sum of **Energy Payments** pursuant PEC / B56, plus **Constrained-Off Payments** pursuant to PEC / B64, if any, plus **Constrained-On Payments** pursuant to PEC / B67, if any, do not recover the offered cost of the **Unit** over the **Dispatch Day**, as evaluated by **HTSO** pursuant to PEC / B68.2;

   (b) **HTSO** instructed the **Unit** to start up and synchronise so as to generate **Energy** on the **Dispatch Day**; and

   (c) in no **Dispatch Hour** during the **Dispatch Day** was the **Unconditional Must-Run Output** of the **Unit** greater than zero.

2. In making its determination of offered cost of a **Unit** over the **Dispatch Day**, **HTSO** shall determine the cost of generating the **Unit's Meter Quantity** in each **Dispatch Hour**, given the **Offer Price Function** and **Offer Start-Up Price** of the **Unit** for that **Dispatch Day**, and given the synchronisation status of the **Unit** at the start of the **Dispatch Day.**

3. Additional **Constrained-On Payments**, if any, shall be equal to the amount, as determined by **HTSO**, by which the **Participant Generator** would otherwise under-recover costs pursuant to PEC / B68.1a, in respect of the **Unit**, over the **Dispatch Day**.

Paragraph 69 limits the Units in respect of which any Constrained-On Payments or Constrained-Off Payment may be made:

69. Exceptions to Making of Constrained-On and Off Payments

1. **HTSO** shall make no **Constrained-On Payments** or **Constrained-Off Payments** in respect of a **Unit** for any **Dispatch Hour** of a **Dispatch Day** in respect of which:

   (a) the **Declared Information** of the **Unit** is revised during the **Dispatch Day**;

   (b) **Metering Data** has not been supplied in respect of a **Dispatch Hour** in the **Dispatch Day**;

   (c) the **Daily Offer** or any component of the **Daily Offer** of the **Unit** is revised during the **Dispatch Day**; or

   (d) the **Unit** is deemed to be non-compliant with a **Dispatch Instruction**, in accordance with the **Operating Code**, at any time during the **Dispatch Day**.

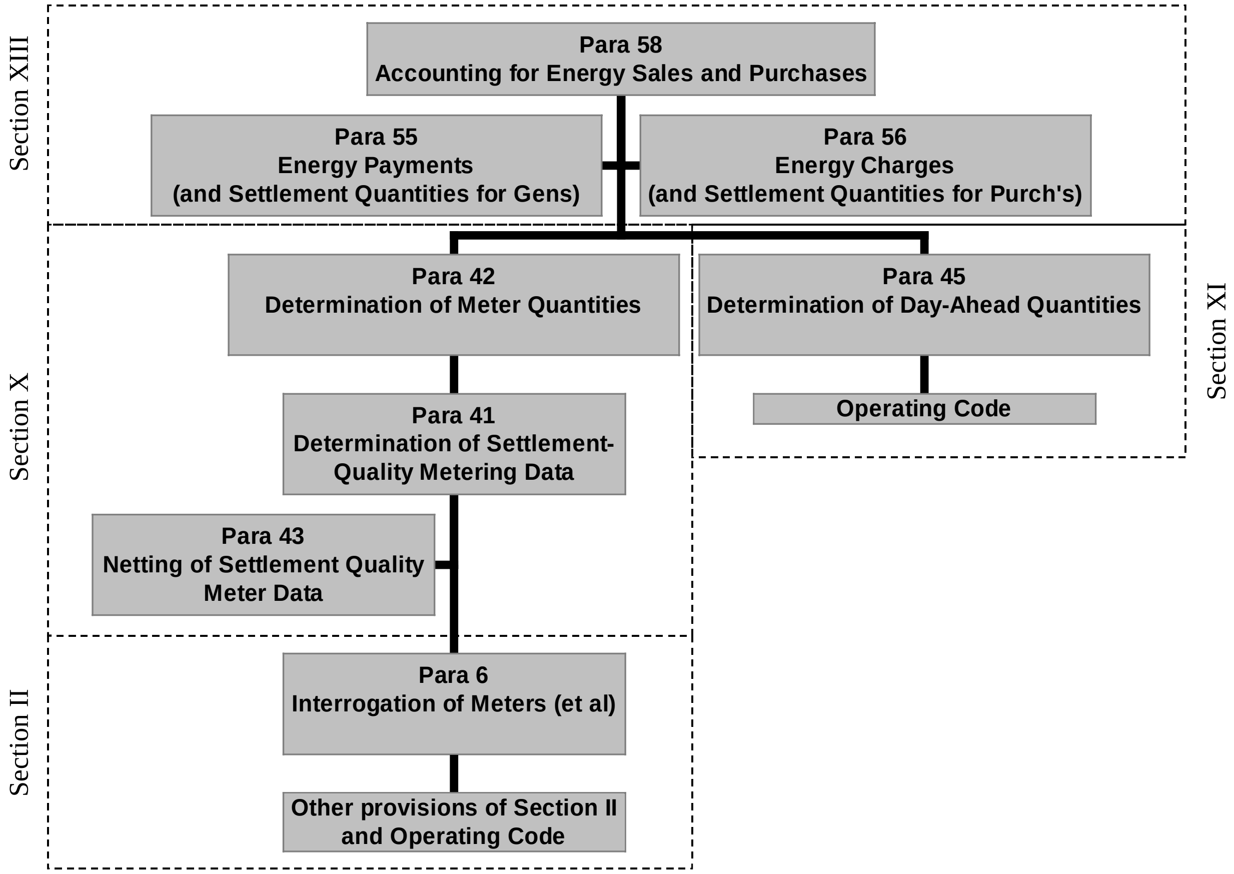
2. **HTSO** shall make no **Constrained-On Payments** or **Constrained-Off Payments** in respect of **Special Units**, **Units** in foreign countries, or in respect of generating entities represented by the **Special Participant**.

12. HOW ARE SETTLEMENT QUANTITIES DETERMINED?

Settlement Quantities are used in conjunction with SMPs to determine the Energy Payments and Energy Charges of Participants. Settlement Quantities are determined as a result of first determining Metering Data, Settlement Quality Metering Data, Meter Quantities, Day-Ahead Quantities and Transmission Loss Factors.

The following diagram is an illustration of the sections of the Power Exchange Code in which the factors that comprise Settlement Quantities are specified:

Figure 12.1



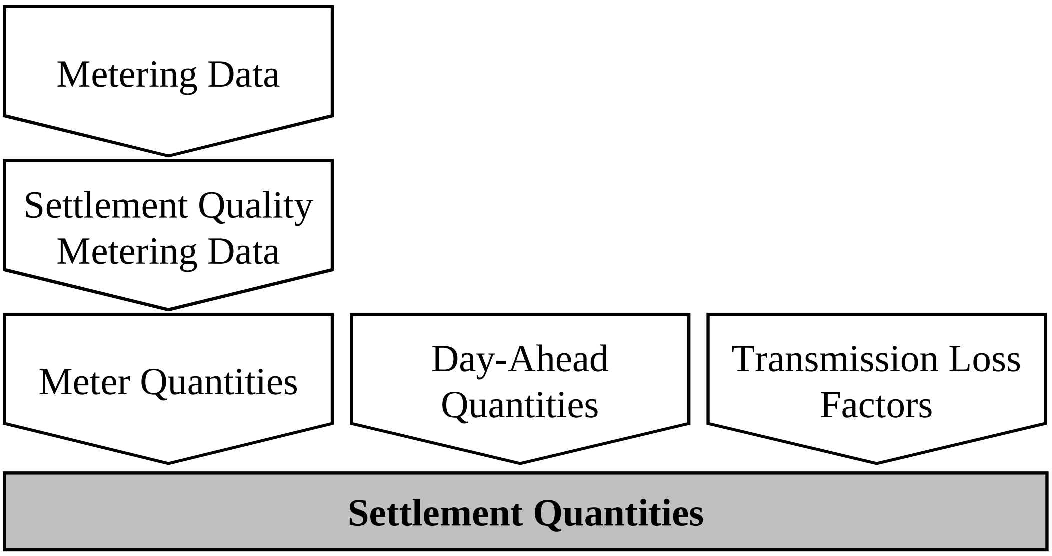
Paragraph 54 of Schedule B of the Power Exchange Code specifies that on each Calculation Day, the HTSO records in each Participant's account the revenues and costs for energy sales and purchases through the trading arrangements:

54. Timing of Calculation of Daily Settlement Amounts

On the **Calculation Day**, **HTSO** shall calculate **Energy Payments** and **Energy Charges** for each **Participant**, for each **Dispatch Hour** of the **Dispatch Day** in respect of that **Calculation Day**.

Paragraph 55 of Schedule B of the Power Exchange Code specifies that the transaction each Calculation Day for each Generator records the product of its hourly Settlement Quantity and the corresponding SMP, summed over the Dispatch Day. The Settlement Quantity is calculated as the sum over all Units owned by the Generator of Meter Quantities (i.e. Units in Greece), adjusted for transmission losses, plus the sum of the Day-Ahead Quantities (i.e. Units outside Greece), also adjusted for transmission losses:

Figure 12.2



55. Energy Payments

HTSO shall calculate, for each **Dispatch Day** in respect of each **Participant Generator**, a daily **Energy Payment** in accordance with the following equation:

$$EP_{gd} = \sum_{t=1}^{24} SQ_{gt}\ SMP_t$$

where the **Settlement Quantity** for a **Participant Generator** g in **Dispatch Hour** t is calculated in accordance with the following equation:

$$SQ_{gt} = \sum_{u \in g} \left[\sum_i MQ_{uit}\left(1 + TLFG_{it}\right)\right] + \sum_i DAQ_{git}\left(1 + TLFG_{it}\right)$$

where $u \in g$ signifies that the summation is made for each **Unit** u that, according to its **Registered Information**, is owned, or in the case of the **Special Participant**, represented, by **Participant Generator** g.

Paragraph 56 specifies an equivalent calculation for Purchasers:

56. Energy Charges

HTSO shall calculate, for each **Dispatch Day** in respect of each **Participant Purchaser** with **Load**, a daily **Energy Charge** in respect of such **Load**, in accordance with the following equation:

$$EC_{pd} = \sum_{t=1}^{24} SQ_{pt}\ SMP_t$$

where the **Settlement Quantity** for **Participant Purchaser** *p* in **Dispatch Hour** *t* supplying **Customers** in Greece is calculated in accordance with the following equation:

$$SQ_{pt} = \sum_{i} MQ_{pit} \left(1 + TLFP_{it}\right)$$

and where the **Settlement Quantity** for **Exporting Purchaser** *p* in **Dispatch Hour** *t* is calculated in accordance with the following equation:

$$SQ_{pt} = \sum_{i} DAQ_{pit} \left(1 + TLFP_{it}\right)$$

Meter Quantities are calculated in section X of Schedule B (i.e. paragraphs 39 to 43).

Paragraph 42 specifies that Meter Quantities must be based on Settlement Quality Meter Data, which is appropriately aggregated over the meters corresponding to the Participant concerned, and appropriately adjusted to account for Distribution-Embedded Units and Eligible Customers connected to the network.

Paragraph 43 specifies the conditions under which Settlement Quality Meter Data values of auxiliary Load equipment may be netted from those of Units.

Paragraph 41 specifies the means by which unprocessed Metering Data is processed so as to be Settlement Quality Meter Data.

Day Ahead Quantities are determined in accordance with section XI of Schedule B (i.e. paragraphs 44 and 45), which refer to the provisions of the Operating Code for accepting Offers in respect of Units in foreign countries, and accepting export Nominations.

Section II of Schedule B, and in particular paragraph 6, specify the terms under which Metering Data is obtained.

13. HOW ARE ANCILLARY SERVICES HANDLED?

Ancillary Services are those services other than the production of energy required to maintain a stable frequency and voltage on the transmission system. The HTSO is responsible for procuring and using these services in its scheduling and dispatch of generation and in its use of the transmission system. All costs incurred by HTSO in procuring Ancillary Services are passed on to Participants through Uplift.

The Operating Code specifies certain mandatory Ancillary Services. HTSO procures other Ancillary Services through Ancillary Service Agreements with individual Participants. These agreements specify the obligations of Participants to provide Ancillary Services and the terms by which they are paid, including payment for some mandatory Ancillary Services. Ancillary Services for which Participants sign agreements are:

- Automatic Generation Control;
- Operating Reserve;
- Contingency Reserve;
- Reactive power; and
- Black Start

For each type of non-mandatory Ancillary Service, HTSO would from time to time identify a need - perhaps on a regional basis - and open contracts for bidding, and select the least cost tender. However, for as long as PPC dominates the industry, the prices paid by HTSO for such contracts would be cost-regulated. If there were some profit component in those regulated prices, then that would also be determined on some standard regulatory basis. Independent generators would choose whether or not to sign these regulated contracts and in the long-run it is envisaged that contract prices would be set by competitive tender.

For mandatory Ancillary Services that HTSO pays for, HTSO would sign contracts with generators and the prices paid by HTSO for such contracts would also be cost-regulated.

Participants with agreements to provide Ancillary Services declare their capability to provide each contracted Ancillary Service by 12:00 of the day immediately preceding the Dispatch Day. It is the responsibility of each Participant to ensure that such declarations comply with the terms of its Ancillary Service Agreements.

When HTSO determines the Generation Schedule for the following Dispatch Day, it makes an initial selection of hour-to-hour providers of energy and Ancillary Services from those sources available, adhering to the principles of a least-cost and security constrained operation of the system, and in accordance with the methods specified in the Operating Code and Ancillary Services Agreements.

Generators not selected in the Generation Schedule are able to re-declare their availability downwards for the following Dispatch Day. This means HTSO must schedule sufficient generators day-ahead to cover for the possibility of unforced generation outages and errors in its load forecast. Even if these generators are not called upon to run, they may be entitled receive a payment for being available in accordance with an Ancillary Service Agreement.

On an on-going basis right up until the Dispatch Hour, HTSO may subsequently modify the day-ahead schedule. HTSO may notify a generator with which it has an arrangement to provide Ancillary Services that it is required to synchronise or standby in order to provide one or more types of Ancillary Service.

In addition to payments made through Ancillary Services Agreements, generators may also be entitled to Constrained-On and/or Constrained-Off payments if they are dispatched out of merit in order to provide an Ancillary Service. These payments are described in section 11.

14. HOW ARE IMPORTS/ EXPORTS HANDLED?

The Power Exchange Code makes provision for the commercial aspects of trading energy and ancillary services across Greece's interconnectors with other countries. The treatment of interconnectors is designed to accommodate PPC's existing interconnector agreements with other system operators, in Bulgaria, FYROM, and Albania, whilst allowing Participants that meet certain requirements to also trade internationally.

14.1. Exporting Purchasers

Exporting Purchasers are Participants that purchase energy through the PEC for the purpose of export from Greece to supply customers in another country. An Exporting Purchaser must hold a generation authorisation and meet the appropriate technical requirements to export energy from Greece. In particular an Exporting Purchaser:

- must hold the rights to use interconnector capacity out of Greece before the HTSO will schedule an export transaction. (The methods by which Exporting Purchasers may obtain rights to use interconnector capacity out of Greece are outside of the STA);
- is limited in the amount of energy it can export in a given hour by the amount of capacity specified in its generation authorisation, less the aggregate of the HTSO-registered maximum loads for the customers in Greece for which the Exporting Purchaser has responsibility (in the case of entities that are also holding a supply authorisation);
- must make the appropriate arrangements with SOs in adjoining countries for the receipt of the energy; and
- must meet other appropriate technical requirements specified by the HTSO.

Where an Exporting Purchaser wishes to export energy from Greece it must nominate the amount of its exports by 12:00 of the day prior to the Dispatch Day. Exporting Purchasers do not nominate a maximum price they are prepared to pay to purchase this energy; they only nominate a quantity to export for each Dispatch Hour.

The limit on the amount of capacity that can be exported, with respect to the authorisation of the Generator, is monitored by the HTSO but any consequences of non-compliance is an RAE matter and is outside of the STA.

14.2. Units in Foreign Countries

Entities with generating Units located in another country may import energy into Greece for the purposes of supplying customers. In order to import energy across an interconnector the entity must be an Authorised Supplier and meet the required technical requirements to import energy to Greece. In particular, the entity must:

- hold rights to use interconnector capacity into Greece (the methods by which Participants may obtain rights to use interconnector capacity into Greece are outside of the STA); and
- arrange with system operators outside of Greece for the delivery of energy from its units to Greece.

To import energy into Greece from a Unit outside of Greece a Participant must submit a Daily Offer for the Unit by 12:00 of the day prior to the Dispatch Day, just as it would if the Unit was located in Greece. However, the Daily Offer must be:

- made in accordance with the Participant's rights to use an interconnector; and
- made in accordance with the Participant's rights to transmit energy from the Unit to the interconnector.

The only difference between an Offer made in respect of a Unit located outside of Greece and a Unit located in Greece is that there is no Offer price restriction on Units located outside Greece. This is in view of the practical difficulties of auditing the costs of generating plants located in foreign countries.

14.3. Scheduled Interconnector Flows

Offers in respect of Units in foreign countries and valid export nominations are taken into account in both the unconstrained forecast generation schedule and the constrained forecast generation schedule.

Offers in respect of Units in foreign countries that are accepted in the *constrained forecast generation schedule* and all valid export nominations are accepted by the HTSO and aggregated into a single scheduled interconnector flow for each hour for each interconnector so long as:

- the net scheduled quantity represents a feasible flow on the interconnector with respect to its available transfer capacity, as determined by the HTSO after taking into account the HTSO's need to reserve some portion of the capacity of the interconnector to meet its system security obligations;

- confirmation has been received from the adjoining system operators that arrangements have been made for the receipt of energy from the Exporting Purchasers concerned, and / or the delivery of energy by the Generators with foreign Units concerned; and
- confirmation has been received from the adjoining system operators regarding the net (ie, aggregated) scheduled quantity on the interconnectors in each relevant time period, and the terms with which any imbalances from that schedule are managed.

Where, for one of these reasons, the HTSO cannot schedule an Offer from a foreign Unit that was accepted in the constrained forecast generation schedule, or cannot accept a valid export nomination, the HTSO modifies the constrained forecast generation schedule. In doing so it adheres to the principle of maximising the economic value of the transactions that can occur, subject to its system security obligations. If it is necessary to curtail Offers from foreign Units or to curtail valid export nominations, the HTSO does so in accordance with the terms with which the rights to use interconnector capacity were granted.

14.4. Dispatch

Exporting Purchasers and Units in foreign countries incorporated into the scheduled interconnector flow cannot update their schedules once the constrained forecast generation schedule has been made for the Dispatch Day. Accordingly, Offers in respect of Units in foreign countries are not taken into account in the real-time Dispatch.

The net amount scheduled on individual interconnectors may however be adjusted by the HTSO and neighbouring control area operators in the event of unexpected transmission system conditions, and if it is agreed and necessary to do so in order to preserve reliability.

14.5. Metering

The HTSO does not require meter readings from Units in foreign countries or Exporting Purchasers in order to determine Meter Quantities for settlement of international trade, rather it uses the quantities accepted in the constrained forecast generation schedule, adjusted for transmission losses, as described in section 14.6.

The HTSO is required to have installed a multi-function meter capable of measuring the net energy transfer on each international interconnector for each one-hour period. The HTSO is responsible for obtaining hourly readings from these meters.

14.6. Settlement

Participants are paid the SMP, adjusted for transmission losses, for their energy quantities accepted in the constrained forecast generation schedule for their Units located in foreign countries. Exporting Purchasers pay the SMP for their energy quantities, adjusted for the cost of transmission losses, accepted in the constrained forecast generation schedule.

HTSO determines where energy imported and exported is nominally delivered to or taken from the Greek transmission system in accordance with Parargraph 44:

44. Designation of Import Nodes and Export Nodes

1. For the purpose of this Schedule B, **HTSO** shall establish one or more **Import Nodes** in respect of each **Unit** located outside of Greece. Such **Import Node(s)** shall be the **Node(s)** at which **Energy,** imported in accordance with the right of the **Participant Generator** owning the **Unit** to use the **Interconnector(s),** is scheduled to be delivered to the **Transmission System**.

2. For the purpose of this Schedule B, **HTSO** shall establish one or more **Export Nodes** in respect of each **Exporting Purchaser**. Such **Export Node(s)** shall be the **Node(s)** at which **Energy,** exported in accordance with the right of the **Exporting Purchaser** to use the **Interconnector(s),** is scheduled to be taken from the **Transmission System.**

HTSO determines the quantity of international trade for a Participant by determining a Day Ahead Quantity for each Dispatch Hour for the Participant's imports and exports accepted in the constrained forecast generation schedule in respect of each interconnector. For the purposes of settlement, Day-Ahead Quantities are delivered to or taken from the transmission system at their associated import node or export node. Section 12 describes how these quantities are adjusted for transmission losses and aggregated into Participants' Settlement Quantities.

The HTSO and neighbouring system operators settle any imbalances between scheduled and actual flows across their interconnectors. There may be a net cost to the HTSO for settlement of these imbalances if:

- actual energy flows across the interconnectors differ from those scheduled in the constrained forecast generation schedule; and
- the price or effective price for settling imbalances in interconnector flows in the HTSO's agreements with neighbouring control area operators differs from the SMP in the STA.

The net cost of interconnector trade is accumulated to the Uplift account as it is incurred, in accordance with Paragraph 78:

78. Determination of Hourly Net Energy Cost of Interconnection Flow Deviations

On the **Calculation Day** in respect of a **Dispatch Day**, **HTSO** shall determine the net **Energy** cost of **Interconnector** flow deviations in respect of each **Dispatch Hour** in that **Dispatch Day** as being equal to the sum, over all **Interconnectors**, of:

1. net scheduled inflows of **Energy** over an **Interconnector** pursuant to PEC/B**Error! Reference source not found.** (excluding any amounts scheduled by **HTSO** with an **External System Operator** to offset or pay back previous **Interconnector** schedule deviations), minus

2. actual net inflows of **Energy**, all multiplied by

3. the **SMP** in respect of the **Dispatch Hour**, and

4. adjusted, as **HTSO** determines appropriate, by a relevant **Transmission Loss Factor** in respect of the **Interconnector**.

14.7. Treatment of Existing Interconnector Agreements

The existing Interconnector agreements place all rights and responsibilities on PPC as the party representing the Greek system. Since Article 15 of the Electricity Law prevents HTSO from contracting for the sale or purchase of electricity unless required to do so for the provision of ancillary services, HTSO cannot take over all responsibilities of these agreements. Rather, HTSO would take over lead responsibility for the execution of the agreements on the Greek side, with certain functions assigned to PPC.

HTSO would have overall technical responsibility for the execution of the agreements, but the specific commercial rights and responsibilities would be split as follows:

1. HTSO would be responsible for all imports and exports scheduled within the day. When HTSO schedules a short-term import or export to cover an emergency or provide system support it can be regarded as making a purchase or sale under an ancillary services agreement with the foreign system operator.

2. HTSO would be responsible for deviations from schedule and any subsequent scheduled energy exchange required as a result of the deviation from schedule.

3. PPC would be responsible for day-ahead (or longer) scheduled exchanges to and from the foreign system operator – in effect PPC would retain the existing rights and

responsibilities for these scheduled energy exchanges between systems. PPC/DBU would schedule imports from foreign systems in accordance with the Power Exchange Code, and PPC/GBU would schedule exports to foreign system in accordance with the Power Exchange Code. Thus, the net costs or benefits of the scheduled transfers would be retained by the PPC Group.

15. WHAT CHARGES AND PAYMENTS ARE SETTLED UNDER THE POWER EXCHANGE CODE?

Paragraph 28 of Schedule B of the Power Exchange Code specifies that energy, Uplift and transmission payments and charges are settled under the Power Exchange Code:

> **28. HTSO Responsibilities**
>
> **HTSO's** responsibilities with respect to settlement are to:
>
> 1. determine **SMPs** and **Settlement Quantities**, and in turn determine payment amounts to **Participants** providing **Energy** and determine charge amounts to **Participants** utilising **Energy**;
>
> 2. calculate and settle payments and charges in respect of **Ancillary Services** and other **Uplift** costs; and
>
> 3. calculate and settle payments and charges in respect of transmission use-of-system charges and transmission connection charges.

Numerous debit and credit transactions involving the HTSO's settlement accounts constitute the process of "settlement". These transactions, for energy, Uplift and transmission payments and charges, are set out throughout Schedule B.

15.1. Energy

Much of Schedule B is devoted to the determination of Energy Charges and Energy Payments, and the means by which energy is metered, settled and billed. Paragraph 58 specifies the way in which Energy Charges and Energy Payments determined are transacted through the HTSO settlement accounts so as to be assigned to Participants:

> **58. Account Transactions for Energy Charges and Energy Payments**
>
> On the **Calculation Day** in respect of a **Dispatch Day**, **HTSO** shall:
>
> 1. debit the **Energy Sales and Purchases Account** and credit a P**articipant's Participant Trading Account** by the **Participant's Energy Payment** amount for that **Dispatch Day**; and
>
> 2. credit the **Energy Sales and Purchases Account** and debit a **Participant's Participant Trading Account** by the **Participant's Energy Charge** amount for that **Dispatch Day**.

Since the total of Energy Charges will not equal the total of Energy Payments in any given Dispatch Hour, a transaction is made every day to the Uplift settlement account to clear the difference. This transaction is described in Paragraph 59.

15.2. Uplift

Paragraph 29.2 specifies the categories of cost and payment that constitute Uplift and are settled under the Power Exchange Code. They are:

- Ancillary Services;
- HTSO administration charges;
- Interconnector net costs;
- Special Unit costs;
- Constrained-On Payments and Constrained-Off Payments;
- losses adjustments; and
- additional charges (other items).

Section XV of Schedule B (paragraphs 71 to 73) specifies the rules for Ancillary Services. The costs incurred by the HTSO through Ancillary Service agreements it enters into are recovered through the Uplift sub-account for Ancillary Services. Costs relating to Ancillary Services providers that may be due Constrained-On Payments or Constrained-Off Payments are accounted for in the Uplift Sub-account for Constrained-On Payments or Constrained-Off Payment, not the Uplift sub-account for Ancillary Services. The treatment of Ancillary Services is also described in section 13 of this document.

Paragraph 74 of Schedule B specifies the treatment of HTSO administration charges. The HTSO will be regulated by RAE as to the administration costs it can recover and it will not necessarily be able to pass through all costs at the same time as it incurs them.

Paragraphs 78 and 79 of Schedule B specifies the treatment of Interconnector net costs. Interconnector net costs are the costs of managing the Interconnectors. They include:

- Direct costs incurred by the HTSO (paragraph 79.2); and

- the cost, relative to SMP, of unscheduled flows and subsequent scheduled flows to offset or pay back previous unscheduled flows. These costs (paragraph 78) are not direct costs to HTSO, as is described below under "losses adjustments".

Paragraph 75 of Schedule B specifies the treatment of Special Unit costs. HTSO, so as to comply with the Law, makes additional payments to Special Units equal to the difference between the amounts specified in the Law and the payments they otherwise receive under the Power Exchange Code for energy. Since these additional payments may not always equal the charges the HTSO is authorised by RAE to recover from Participants in respect of Special Units, in a month, the HTSO will need to arrange for the appropriate accounting and banking facilities as required so as to account for and manage the difference on an on-going basis.

Section XIV of Schedule B specifies the rules for Constrained-On Payments and Constrained-Off Payments. The treatment of these payments is also described in section 11 of this document.

Losses adjustments are net payments received by the HTSO since, because of the effect of using marginal Transmission Loss Factors in the calculation of Settlement Quantities (refer to section 12 of this document), total Energy Charges will normally exceed total Energy Payments. As described above, Paragraph 59 specifies a transfer from the Energy Sales and Purchases Account to the Uplift sub-account for losses by the amount of the difference. Paragraph 78 (relating to Interconnector net costs) also modifies the Uplift sub-account for losses, but since the effect of this paragraph is to make a transfer between two Uplift sub-accounts, there is no net effect on total Uplift costs.

Paragraph 81 of Schedule B specifies other charges that the HTSO can recover through Uplift. These consist of charges so as to deal with rounding errors, charges related to interest and credit facilities that the HTSO is not authorised to otherwise allocate directly to Participants, charges relating to payment default in certain situations, and residual costs attributable to the Special Participant.

Penalties, which may be assessed by the HTSO according to paragraphs 18 or 102 of Schedule B, or as otherwise provided in the Power Exchange Code or Operating Code, are not settled under the Power Exchange Code. Paragraph 103 specifies that HTSO informs RAE of the assessed amounts, and settlement, if any, is not an HTSO responsibility.

Paragraph 85 specifies the way in which Uplift Charges are transacted through the HTSO settlement accounts so as to be assigned to Participants:

85. Account Transactions for Uplift Charges

Immediately subsequent to determining **Uplift** charges pursuant to PEC/B84, **HTSO** shall:

1. credit each of the **Uplift** sub-accounts specified in PEC/B29.2 which had a debit balance as of the end of the **Calculation Day** in respect of the last calendar day in the month by an amount equal to that debit balance;

2. debit each of the **Uplift** sub-accounts specified in PEC/B29.2 which had a credit balance as of the end of the **Calculation Day** in respect of the last calendar day in the month by an amount equal to that credit balance; and

3. debit each **Participant Purchaser's Participant Trading Account** an amount equal to that determined pursuant to PEC/B84 for that **Participant Purchaser**.

In addition to Uplift, Paragraphs 76 and 77 of Schedule B specify rules for the treatment of renewable and/or cogeneration entities on the Non-Interconnected Islands. Payments and/or charges to these entities are similar to those in respect of Special Units, and the HTSO is responsible for their management and settlement. These payments and charges are separate from Uplift because the entities concerned are either not Participants, or are not acting in the capacity as Participants.

15.3. Transmission

Section XVIII (paragraph 86) of Schedule B specifies the way in which transmission charges determined in accordance with Transmission Connection Agreements and Transmission Use-of-System Agreements, and transmission payments determined in accordance with the Transmission Control Agreement, are transacted through the HTSO settlement accounts.

Since the transmission payments may not always equal transmission charges the HTSO in a month, the HTSO will need to arrange for appropriate banking and accounting facilities as required so as to account for and manage the difference on an on-going basis.

Charges in respect of entities that have entered into Transmission Connection Agreements but are not Participants will not be settled through the Power Exchange Code.