SOUTH EAST EUROPE
WHOLESALE MARKET OPENING

Report on Task 6
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DRAFT
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EXECUTIVE SUMMARY

Pöyry Energy Consulting and Nord Pool Consulting have been commissioned by the World Bank to develop a study on Wholesale Market Opening for the electricity market in South East Europe. The key outputs of the study are to propose a regional market design and an action plan for implementation. This report covers task 6 of this study as a follow up of the previously distributed report for tasks 1-4 of the project.

The geographical focus of the report is the seven Contracting Parties to the Treaty establishing the Energy Community, i.e., Albania, Bosnia and Herzegovina, FYR of Macedonia, Montenegro and UNMIK. However, the creation of a regional wholesale electricity market will naturally span a broader geographical scope than this.

The recommendations as set out in this report are founded on the decisions and recommendations found in various European organizations like EU, Europex recommendations, ETSO&ENTSO-E recommendations and UCTE. A full reference of these documents is part of the appendix “List of references” found in the end of this document.

The Consultant’s recommendations can be summarized as follows:

To create a flexible Regional cooperation enabling competitive wholesale trading of electricity between the involved participants in the SEE region based on the successful experiences from other European markets.

This recommendation is based on the following key elements:

- Implementation of Balance responsibility for wholesale market participants;
- A regional market founded on a Day-ahead market with implicit auction with allocation of cross-border capacity to the market;
- Harmonisation of rules and regulations between the SEE parties;
- Removal of the traditional Full supply contracts to Suppliers and Eligible Customers;
- Transparency and equal market access to all.

To be able to meet this target, political willingness and support for the required changes and commitment to the action plan(s) from all the stakeholders in the region are vital.

A prioritized task is a market simulation environment for the SEE region to be able to perform dry runs and various market simulations. Dry run in this context has two meanings; a possibility to simulate/train market participation, and to simulate different market setup scenarios.

It is also recommended to focus on the establishment of an initial SEE regional market including at least two or three market areas to start with and implement a phased approach to allow for new entrances to follow.
BACKGROUND

Overall Project Description

The countries of South East Europe (SEE) are working with the European Union (EU) to develop an Energy Community (a regulatory and market framework for a regional energy market in South East Europe) and integrate it into the European Union Internal Energy Market. The SEE countries have acknowledged that solutions based on isolated national markets are neither capable nor desirable as a means to attempt to close investment gaps and emerging energy demand and supply imbalances. Building upon their experience to cooperate in the power sector, in recognition of potential gains from increased trade, and as part of a wider movement to strengthen regional cooperation and advance European integration, the governments of SEE countries signed a Memorandum of Understanding on the Regional Energy Market in South East Europe and its Integration into the European Union Internal Energy Market - on December 8, 2003 in Athens, Greece. A treaty was signed in Athens on October 25, 2005 by the European Commission on behalf of the EU and Albania, Bosnia & Herzegovina, Bulgaria, Croatia, Former Yugoslav Republic of Macedonia, Montenegro, Romania and Serbia, as well as UNMIK, as Contracting Parties. The Treaty Establishing the Energy Community (the Treaty) became effective on July 1, 2006. Bulgaria and Romania joined the EU in January 2007 and became Participants under the Treaty along with other EU Member States including Austria, Greece, Hungary, Italy and Slovenia. Turkey, Moldova, Ukraine, Norway and most recently Georgia joined as Observers and may eventually join the Energy Community.

By signing and ratifying the Treaty the participating countries committed themselves to developing a regional energy (power and gas) market in South East Europe. Significant progress has been made in the SEE area in terms of vertical unbundling of state-owned power utilities, regulatory reforms and establishing frameworks for regional cooperation between members of the Treaty. The Treaty also requires the opening of the electricity market in South East Europe to all non-household consumers by January 2008. As the deadline for electricity market opening has already passed, prospects for an effective liberalization process where non-household industrials and commercial consumers can freely choose (or opt to choose) their electricity suppliers are not yet advancing.

Content of this report:

This report is defined as task 6 in the overall project, and the objectives as taken from the ToR and Inception report are:

The Consultant will propose a Regional Market Design and connected Action plan. The proposal should take into consideration the possibility of stepwise implementation, starting from simple arrangements (e.g. bilateral contracts) to more complex mechanisms operated by a regional market operator or national operators in a market coupling.

A recommendation for an action plan for the implementation of a SEE RMD will leverage from the experience and know-how from all other existing competitive electricity markets (both national and regional) in Europe.
Report overview:

In order to answer to the ToR as set out in the text above, the Consultants have divided the report into four main chapters:

- SEE wholesale market opening requirements
  This chapter discusses the main topics to enable a regional market opening, discuss the various instruments and explain the recommendations.

- Regional Market Design
  This consists of the recommended regional marked design including its main building blocks and possible organizational models.

- Transition Phase
  This chapter describes the activities to reach the goal of a full market opening in 2015.

- Action Plan
  This chapter contains the required activities including a tentative work plan to reach the goal of a full market opening in 2015.
SEE WHOLESALE MARKET OPENING REQUIREMENTS

Introduction

The introduction of competition to electricity business is not a new topic. Vertical and horizontal unbundling, national and regional, pooling and voluntary markets, centralized and decentralized dispatch, regulated and market based pricing, ISO and TSO, implicit and explicit transmission capacity auctions, auction based and continuous trade based electricity markets, nodal and area-based pricing – these are only some of the expressions you will meet when trying to analyze what the different national authorities have tried out.

The development and experience from especially other European markets show that some main design principles are considered as the best way to proceed with the transitioning process: a regional market based on competition, implicit auction of transmission capacity in case of congestions, two-price market model, physical plus financial market and shortest possible settlement periods.

The most obvious conclusion from all reform experiences is that a competitive electricity industry is not implemented from one day to another. In market areas where authorities and organizations have cooperated based on a willingness to focus on the functioning of the required mechanisms – through proper framework, correct assigning of responsibilities and meaningful regulation – the development has been positive and the electricity business has carried out a successful transition from publicly run to competitive.

Although Europe and other parts of the world are converging to a unified definition of a functioning electricity market design, there are still issues being discussed and alternative solutions existing next to each other.

Crucial for design and implementation of an electricity market is a clear goal: the transition from publicly run to competitive market solutions. The two main mechanisms clearly stated as best suitable for this purpose are competition and regulation; not as a mix, but competition for generation, supply and consumption on one hand and regulation for grids and system operation on the other hand:

- competition (generation, retail and consumption) in order to achieve cost efficiency and maximum utilization of infrastructure
- regulation of monopoly (grid and SO) functions in order to achieve cost efficiency and a defined level of supply quality

The only place regulation shall affect competition is where the framework for – and the proper function of – competition is created.

The solutions for the SEE market should be based on the experience from existing markets with focus on utilizing the sum of the experiences from other markets.

In the following the most important requirements affecting SEE plus thereto belonging instruments and constellations are discussed, which also result in our recommendations for SEE.
Balance Responsibility, Regulated Prices and Market Price

Contracts with regulated prices will always withdraw the contracted volume from the wholesale market. A functioning wholesale market is dependent on price dependent bids in order to create liquidity. Regulated price contracts will thus not harm the functioning of the wholesale market if they represent price independent consumption volumes.

In SEE regulated price contracts exist as “support” to industry, business and households. Business and households are typical price independent consumers, i.e. they are not able to respond on short term price peaks. Thus maintaining the “support” of these two groups in a transition period will not disturb the market. Important for the transition period’s duration is although that these two groups are able to respond on long term prices. They should thus be given a timeline for eventual tariff price increases/corrections in order to facilitate their preparations for eventually higher market costs during/after the transition period.

Industry, as the third group, will due to the introduction of balance responsibility be obliged to trade into balance. This implies that they will have to purchase hourly contracts in addition to the eventual regulated price contracts. Regulated price contracts should only be granted as base load for a longer period and based on the expected consumption (equal to the principle of distribution of EU-CO2 allowances). The hourly contracts purchased through their balance responsibility will introduce the industry to hourly prices in the wholesale market and thus create incentives to respond on price peaks with demand volume flexibility.

Generators will have contractual obligations related to regulated price contracts and other bilateral contracts. The wholesale market will enable the generators to substitute their own generation capacity with cheaper purchases in the wholesale market. Thus the generators will appear in the market as price dependent buyers in addition to the price dependent sell of their surplus capacity.

In the long run, regulated prices will have to be removed as SEE is integrated into the EU and the conditions for the internal EU market for energy are applied.

It is a political decision how fast and to which degree the regulated prices shall be replaced with market prices until 31.12.2014.
Imbalance Management

Basic principles

The basic design principle is that the generators sell their generation capacity and consumers purchase their consumption prior to operational hours. This implies that consumers have to estimate their consumption and purchase it before they start consuming it – and generators have to estimate their generation volume before they generate it. The generators will also be able to sell generation capacity for real-time generation if the sell price achieved is higher than their cost price.

Assuming that consumers estimate their consumption correctly and purchase this from the generators, the input for the real-time operation will be a planned balance between generation and consumption. The load increase and decrease within the same hour is not subject to day-ahead trading. Thus the average load per hour will be the traded volume. This implies that only the average consumption per hour is equal to the average generation per hour and additional instruments are required for TSOs to balance the system in real-time.

Imbalance management

The TSO – as responsible for security and quality of supply – needs instruments enabling him to balance generation with consumption. Imbalances emerge from the consumers and generators variation of load within the operational hour, from wrong estimates regarding consumption and/or generation and unexpected incidents (generation, consumption and/or grid failure).

There are two main issues important for a TSO which will lead to an acceptable preliminary balance before the hour of operation starts:

- The consumers need access to a liquid marketplace, which ensures that they always will be able to purchase their estimated energy consumption. Vice versa the generators need access to a liquid marketplace, which ensures that they always will be able to sell their estimated energy generation.
- The generators and consumers need an incentive to trade into balance, thus not purchase more or less than they will consume or sell more or less than they will generate.

The instruments supporting this are a day-ahead market for energy and a balance responsibility by each wholesale market participant:

- A day-ahead market (DAM) will provide the participants with a marketplace for energy where supply and demand meet to trade their sell and purchase volumes.
- Balance Responsibility (BR) provides the incentive for achieving a balance between contracted and metered energy volume per settlement interval since prices for imbalances are less favorable than prices for energy.

The participation in a physical energy wholesale market requires a set of rules and procedures related to Balance Responsibility. Balance Responsibility is an instrument used by the TSOs to ensure that the consumers and generators have agreed upon energy contracts balancing generation and consumption before real-time operation. Any participant generating more or
less than he has sold in advance or consuming more or less than he has purchased in advance will have the deviation calculated as imbalance.

In Europe the shortest interval for calculation of imbalances is 15 minutes, the longest hourly. For these intervals the imbalances between contracted and physically extracted or injected energy are calculated. The calculation is related to the Balance Responsible’s deviation, where a Balance Responsible can represent his own consumption and/or generation or a group of consumers and/or generators. The imbalance should be priced with a price reflecting the costs the TSO had for achieving the real-time balance in the settlement interval.

The Balancing Power Market will be the source for reserves used to balance prior and during real-time operation – and the Balancing Power Market will be the instrument pricing imbalances. The reserves bid into the Balancing Power Market will also be used for correcting imbalances resulting from incidents. Ancillary services will be the source for reserves balancing other imbalance reasons.

In short, the following is a summary of the above:

A functioning Imbalance Management is dependent on an established Balance Responsibility and an implemented Balancing Power Market or at least an acceptable (fair) price for imbalances.

Balancing Responsibility further implies that traditional full-supply contracts are disabled by the grid/market code. This can be achieved by a deadline for generation plan submission to the responsible TSO (i.e. day-ahead during early evening hours, thus allowing participant to schedule and TSO to plan day-ahead operations) and thereto belonging procedures only allowing changes to the generation plan in special circumstances. This will disable the generator from following his customers load in real-time.

**Investments and Market Prices**

Investment decisions are based on a sufficient enough rate of return and an acceptable investment risk. In competitive electricity business environments investment decisions therefore are based on business plans reflecting expected market prices. These again reflect factors such as expected market development, generation capacity, consumption and interconnection capacity. Due to the uncertainty of these factors Risk Management models and systems are required in order to provide the investment decision with proper input.

This challenges Risk Management models and systems and leads to required prerequisites in order to be functional:

- They need to be able to adjust risks to market situation at all times
- Market risks deriving from regulatory and political changes must be minimized or at least calculable
- Transparency regarding prices, demand, supply and transmission capacities is obligatory
- Credit risks must be calculable
The experience in Europe and elsewhere in the world shows that the required prerequisites are only satisfied in an electricity business based on a stable or foreseeable market framework, a trusted and accepted reference price for energy and a functional and fair electricity wholesale market:

- It shows that especially long-term investments – larger generation units, large scale industry and interconnection capacity – are dependent on a trusted price reference coming from a DAM. Together with transparency regarding fundamental data influencing the price (both historical and future) the estimation of future scenarios and their probability becomes one of the most important investment terms. Typical investments are increased efficiency in elder generation plants, higher utilization of existing transmission capacity through technical improvements and – when environmental terms are included through subsidies – increased generation capacity coming from environmental friendly or friendlier generation.

- Especially the small-scale consumers have shown to be able to invest in energy efficiency when exposed to higher energy prices and/or expected higher prices in the near future. These investments show a load effect already before the period with expected high prices starts.

- Short-term Demand Side Response (DSR) has become one of the most important instruments for system operators to manage extreme peak load situations. E.g. large-scale industry able to change their load profile within short notice has become an important source for reserve capacity. This has been enabled through investments in industrial process planning and coordination instruments.

- Long-term DSR – in addition to the one coming from the above mentioned small-scale consumers – has become an important factor for increased consumption efficiency. This has been facilitated by improved technology and grid incentives.

The recommended regional market design will after implementation, produce the required prerequisites and facilitate correct investments in generation, consumption and transmission, which lead to increased efficiency, lower costs and higher system quality.
Regional market core requirements

Regional market prerequisites

The development of a regional market is dependent on the internal optimization potential (exchange of energy (MWh/h) and capacity (MW)) and the interconnection capacity between the different control areas participating in the internal optimization. The different interconnections and the electricity balance in the control areas defined as parts of SEE as well as the neighboring control areas will determine the participation in a regional market.

Instead of predefining the member states of the SEE regional market it is recommended to look for the predominant (not in political, but in market sense) control areas in the region, which will be able to function as the founding building blocks for the evolving SEE regional market.

These control areas should show a large enough cooperation potential. In addition they should have sufficient interconnection capacity to secure a stable and functional energy market. The remaining countries in the region will draw advantage of joining this basic market area. The other alternative for these countries is to remain as neighboring markets in the north, east and south of SEE regional market. The future will tell whether they then join the SEE regional market or other neighboring markets.

Our recommendation is to focus on the establishment of the initial SEE regional market including at least two or even three market areas.

A regional market demands for very close cooperation on interconnections and market access to the interconnection capacity. The market’s access to ATC is directly linked to the success potential of the regional market and the reference price determination and acceptance. When it comes to the interconnection between two neighboring areas the access to ATC will to a less degree interfere with the market’s development potential. It influences the reference prices of the two interconnected regional markets, but only a wrong usage – energy flow adverse to price signals – or not transparent usage will be able to harm the market success on both sides.

The two main solutions used to organize the exchange between neighboring areas – either in a regional market or between neighboring regional markets – are implicit or explicit auctioning of available transmission capacity (ATC) on the interconnections:

Regional market with implicit or explicit auctioning of ATC

Implicit auctioning of congested transmission capacity between neighboring areas results in a price for each area leading to maximum utilization of ATC. Explicit auctioning is based on already known prices on both sides of the congested line and results in a price for the ATC and allocation to interested participants.

Implicit auctioning has been performed in the Nordic since establishment of international trade in the Nordic market area, explicit auctioning has during the last decade increased as congestion management instrument on interconnections between both national neighboring markets and regional market interconnections.
Experiences show that the implicit auctioning of capacity always results in correct electricity exchange and maximum optimization of the involved areas. Explicit auctioning only can be seen as an acceptable solution when the interconnection is between two mature markets with well established reference prices and a high degree of transparency.

Due to the relatively small national markets in SEE our recommendation is to focus on the implementation of implicit auctioning of ATC between the involved market areas. This will definitely be necessary if the national markets intend to maintain the high concentration of generation business, which in itself too a large degree conceals the national prices. While explicit auctions are based on individually participating participants and their bilateral trading, implicit auctions are a solution operated by organized market places:

**Cross-border capacity allocation**

Electricity exchange between different market areas is a necessity when increased efficiency and best possible utilization is required. Mostly grids are able to handle such exchange sufficiently, but when included market areas show too large deficits/surpluses in installed generation capacity or seasonal, daily or even hourly load changes are too high existing grid capacity can reach its technical limit. This requires for electricity trading well-suited cross-border transmission capacity management models.

In principle cross-border exchange shall utilize existing transmission capacity as much as necessary and not more than technically possible. But here a question arises: What shall determine the need for capacity or whom shall capacity be allocated to? And what does necessary utilization mean?

This issue is currently discussed in Europe and there are several important views and arguments used in these discussions. Summarized one can say that there are two main parties in the discussion: traders together with traditional participants and portfolio managers.

While the traders and traditional participants focus on arbitrage or avoiding volume risk and price risk through long-term bilateral contracts, the portfolio managers use risk management systems and market instruments to manage risks. This means that traders and traditional participants mainly focus on achieving the best possible price and a volume, whereas the portfolio managers focus on adaptation to the reference price in their market area(s).

This implies that traders and traditional participants require cross-border capacity for future periods resulting in bilateral contracts between a generator and a consumer. Especially in areas with energy deficit or areas with high marginal generation costs, the access to cross-border capacity has an essential meaning for many participants. Traders and traditional participants support explicit auctioning of capacity.

Portfolio managers differ substantially from traders and traditional participants. Their focus is portfolio optimization. They aim at

- balancing as good as possible the physical with the contractual on a day-ahead basis (volume) including price dependency as variable influencing their volume
- hedging against the price risk long- and mid-term by using derivatives
- trading for arbitrage by using derivatives and their knowledge about their market
Portfolio managers rely upon a correct usage of all cross-border capacity to other market areas influencing the own market area’s price. Thus they support implicit auctioning.

Competitive electricity business can be arranged both based on explicit and implicit auctioning of interconnection capacity. The difference is the degree of optimization achievable in each form and whether the mechanism competition is able to function properly or not. SEE as regional market area requires investments and correct trading in order to support the future development – both economic and infrastructural.

We therefore recommend the implementation of implicit auctions. A strong argument supporting implicit auctioning is that even the interconnection between the two most competitive and mature power markets in the world, the Nordic and the German, is unable to be utilized sufficiently through explicit auctioning – thus implicit auctioning will replace the explicit auctioning as soon as possible.

**Bilateral or organized trading**

While some markets have concentrated on bilateral trading others like Nord Pool started by including an organized DAM as an instrument next to bilateral trading. Some few markets even monopolized the market operation by creating a “mandatory” organized DAM (e.g. Spain).

The experience in this context supports economic theory in pricing, market liquidity and flexibility: a regulated market solution (only bilateral or organized allowed) is not suitable as solution, but a fair mix of both and strong competition between them creates products and costs suitable for enabling the positive development of the business.

While bilateral contracts represent the more long-term specter of electricity contracts the DAM is better suitable for the short-term specter.

Liquidity is a main keyword when looking at short-term trade. A day-ahead market will be able to provide enough liquidity if the framework (eligibility of possible participants, imbalance management, imbalance costs and settlement, transparency) supports this function. A liquid DAM will then also be able to create confidence and trust in the determined price and through that develop the reference price for energy in the market area.

Although a DAM should not be dedicated a monopoly on day-ahead contracts it must be recognized that bilateral trading meets technical boundaries when converging to less than weekly ahead of operation – liquidity decreases and prices due to increased operational risks increase. This is the reason why DAM-trading is increasing from year to year in all established DAMs with proper framework supporting the DAM development (e.g. Nord Pool Spot, EEX, OPCOM, APX NL etc.).

Thus DAM trading should be supported when designing the framework for short-term products. This implies that available import and export capacity for usage in implicit auctioning, imbalance management and costs and wholesale market eligibility should be designed to support DAM participation and liquidity. When it comes to the most important difference between DAM and bilateral trading the way to organize trading differs: auction based and continuous based trading:
**Auction or continuous based trading**

Continuous trading is preferred as trading form in many different markets. This trading allows the trading of the same product during a period of time, thus the product can be traded in the means of arbitrage or portfolio adjustment. When it comes to electricity trading, especially short-term contracts including a physical responsibility for delivery, auction based trading has developed to be the preferred trading form.

In auction based trading the participants describe their preferences (volumes related to all possible prices) and submit this to the trading system. The trading system accumulates all individual preferences and determines the reference price for the market. This price is called reference price because it is the only price leading to a balance between supply and demand. Auction based trading thus also concentrates all existing liquidity into one auction trading session, which is the reason why it is the preferred trading form for electricity. Electricity is one of the few commodities where participants need to balance their portfolio through trading – any failure in achieving a balance leads to higher costs due to the imbalance settlement. Thus the trading form and market solution with highest liquidity attracts participants.

The reference price has to be enabled as such by the framework. This leads to next issue: integrated pricing or unbundled prices in regard to energy, capacity, transmission and taxes/fees:

**Grid access**

Wholesale market participants need access to the grid. The access creates costs, both fixed and variable. Cost recovery for the grid owner and system operator is therefore essential for maintaining a high infrastructural standard.

Many different models for grid cost determination have been implemented, but only a few facilitate electricity trading. The simplest model – the point-of-connection tariff – is based on expected scenarios and the marginal costs in each point of connection for these scenarios. This leads to a grid tariff, where the customer of the grid pays his share of the fixed costs and his contribution to the marginal losses in the system, based on scenarios and his point of connection to the system as a whole.

This tariff design enables the participant to trade with anyone in the system without having to include distance or location of the counterpart in the evaluation of the energy price offer.

Negotiated third party access requires from the counterparts that additional costs from the sink’s grid become part of the price. This model is for the purchaser indifferent, but sellers have an incentive to choose the “cheapest sinks” first. In addition the negotiation, although mostly based on standardized contracts, creates additional administration costs.

Stamp tariffs can be said to be a simplified version of the point-of-connection tariff, but when the counterparts are opposed to more than one stamp the tariff becomes distance dependent and thus hostile to electricity trading.

The experience from existing electricity markets show that the point-of-connection tariff facilitates electricity trading more than other applied models. Especially regional markets – as SEE – need a grid cost recovery model where electricity contract counterparts are independent from their location in the grid. Thus the implementation of a point-of-connection grid tariff model is highly recommended. Relatively small national market areas and relatively strong
market concentration in each national market area adds to the necessity of a neutral grid cost recovery model.

**Day-ahead trading or long and mid-term trading**

Existing markets have in this question already clearly stated that day-ahead trading is the preferred trading horizon. Day-ahead trading not only allows a suitable balancing of commitments and available resources with contracts, but is also the preferred source for determination of the reference price for energy. This allows the usage of derivatives for Risk Management and the replacement of traditional long-term bilateral contracts with physical delivery.

The traditional long-term contracts were developed as product for risk management of both price risk and volume risk. After the implementation of day-ahead markets the experience shows that participants experience a minimized volume risk due to liquid DAMs and price risk is handled more efficiently in liquid derivatives markets than in traditional inflexible bilateral contracts. The trading horizon – or risk management horizon – is in today’s European electricity business reduced to some few years ahead. This is in line with other businesses.

We recommend a day-ahead market solution for SEE, especially when considering that electricity business in Europe has become pan-European and the involved companies are seeking for markets with equal organization as the main or home markets (e.g. Nordic, Germany, UK, France, Romania, Italy and Spain).
INTRODUCTION

Enabling a liquid regional trade between the national SEE electricity markets will secure an optimal use of the generation (merit order) and transmission resources.

One of the main features of this regional exchange is to provide a transparent day-ahead reference price of electricity and to enhance the trade across the national borders.

The mix of generation resources in the SEE region, between thermal/nuclear and hydro can be utilized in a more efficient manner if an open regional market is offering day-ahead hourly contracts with full price transparency. This will give both sellers and buyers the opportunity to fine-tune their power portfolios reducing imbalances and hence financial risks in real-time operation. Establishing a trusted day-ahead price index to be used for settlement of forward financial contracts will also be of benefit for investors in new generation.

The day-ahead index can be published both for specific countries and for the whole SEE-region. Alternatively it can be specified one index only for the SEE region complimented by CfDs (contract for difference) between this SEE index and different hubs in the region.

TRANSITION TOWARDS A UNIFIED SEE REGIONAL POWER MARKET

Principles and key factors that will influence the development of a liquid and common, unified and deregulated power market should be based on a common understanding in the industry for a need to reform the existing electricity market and its trading regulations nationally and regionally.

This means that a new framework has to be set by the energy authorities in the region where the following issues are considered:

- The national Energy legislation must support or at least not impede the formation of a pan-regional competitive power market.
- The grid should be recognized as a monopoly and unbundled from the generation environment.
- The large dominant national generation companies should be given the opportunity to expand into regional operation enabling them to meet challenges in a new competitive region-wide power market.

THE ENERGY ACT

The establishment of a regional exchange requires support from the national authorities in each country.

The following items are of crucial importance in this context:

- Unbundling of transmission and supply/generation
- Full transparency requirements regarding essential market data
- Allocation of at least part of the cross-border capacities to the regional exchange
- Details regarding operational procedures for SEE Regional Exchange should be handled by the exchange in close cooperation with market participants, and not regulated in the Energy Act.
- Provide incentives for eligible customers to exercise eligibility

**National producers**

Large dominant producers will be important participants in a regional market. They will normally secure their position and further develop their competitive ability inter regionally. An important prerequisite is full competition with respect to allocation procedures of cross-border capacities so that both incumbent and new entrants in generation have equal access to transmission.

**The regional exchange**

A license to operate a regional exchange under the framework set by the regulators of participating countries should be issued by the regulator in the country where the regional SEE exchange will be located.

**Roles and Responsibilities**

For the operation of a restructured power market, the following two key organizations should work very closely together.

They are identified as:
- The TSO
- Market operator

These two organizations along with the market participants (power generators, power consumers, traders), and the power industry regulators will have clearly defined roles and responsibilities.

**TSO**

As a monopoly the grid owner’s performance and business processes must be monitored by the regulatory bodies.

- TSOs responsibilities as owner of the transmission grid are:
  - Determine rules and requirements for supply quality and security
  - Provide routines to maintain short term power reserves
  - Propose transmission tariffs for the main grid
  - Manage real time operations and handle unpredictable imbalances and unexpected events
  - Cooperate with TSOs of interconnected grids
  - Manage transmission capacity on the neighboring interconnections for the power exchange
The TSOs play a very important role in deregulated power markets. The TSOs’ responsibility to operate, maintain the reliability and quality of the power supply will always set the daily framework for the market operations.

**Market operator - Regional Power Exchange - Day-ahead market**

The Regional Power Exchange will operate as a common market place for the whole regional market and provide services to the TSOs and to the market participants, such as generators, consumers and trading companies.

The core responsibilities are:

- Operate a Day Ahead Market and other related power markets
- Provide a reference price for the financial electricity market
- Use the price mechanisms to alleviate grid congestion through optimal use of available transmission capacity
- Act as a reliable counterpart
- Report to TSOs, participants and to the public required information and data

A power exchange will always in the power market facilitate trade, the transparent handling of price sensitive information, and support market competition and build market liquidity.

**Regulator**

Regulators determine guidelines and bylaws for the regulation of monopolies within the power market.

Normally this will cover issues as:

- Defining guidelines for power system operation
- Defining guidelines for metering
- Defining guidelines for grid tariffs
- Monitoring grid owners and power exchanges costs and profits

Regulator authorities’ responsibility for guidelines, standards and regulations of the power system and the power market may include a service to supervise the conduct of market participants.
Market Participants

Market Participants are legal entities that operate in the wholesale and/or retail markets. They can play multiple roles consisting of one or a combination of the following: generator, consumer, trader, or a retailer.

Grid Tariffs

The preferred grid tariff system to facilitate bilateral trade or trade on a power exchange should be characterized by principles that treat all participants on equal terms.

Most important features will be:

- Market participants should know the transmission costs at their grid connection point by a tariff set by the grid owner or system operator.
- No bilateral negotiations and agreements should be required
- Transmission cost should not be dependent on location of a trade counterpart.

Grid tariffs across the region should be compared and to some extent harmonized to avoid distortions in the markets. Of special concern is if the variable cost varies both between countries and how these variable costs are allocated to either consumers or producers.

The variable cost element in transmission tariffs should be added to the marginal cost for generation when a supplier/generator is setting up their supply bid to a day-ahead market. Similarly for a demand bid the variable transmission cost element should be subtracted from the benefit value.

In some cases the system operators/TSOs are using the variable cost element as a locational signal.

When transiting from a national market to a regional market these locational signals should be harmonized to avoid sub-optimalization.

Another example is environmental fees that might be placed either on the consumer or producer side in different countries. To avoid market distortion this should also be harmonized among member countries

Market Structure

It is vital that a market reform can add value to and support the whole electricity industry. Both large and small companies on the generation and the consumption side should benefit from the market reform and the framework set by the authorities. It must be emphasized that only participation from all parties will give a reliable and trusted business platform that can build liquidity. The services offered by a regional exchange must add value and incentives to the individual participant.

The following objectives are essential in an electricity market reform:

- To obtain market liquidity
- To increase efficiency within the power industry
To achieve the required balance between power generation capacity and power demand both in the short and long term
To reduce regional differences in electricity prices

For the smaller national SEE markets to meet these objectives, it is important that they are integrated with the larger markets into one unified, liquid regional electricity market.

**Requirements**

The following are overall requirements for a market reform:
- All participants trade on equal terms
- Market transparency providing the same information at the same time to all participants
- A proven method for congestion management
- Balancing market
- Efficient market settlement and reporting

The following are other features that could be included:
- Intraday
- VPP (Virtual Power Plants) – auction of generation capacity to increase competition in the market

Comments to the above bullet points are as follow:
- Participants trade on equal terms means a common book of rules and that all relevant information as transparent market information and available transmission capacities are available for all market participants at the same time
- Congestion management is conducted by using an implicit auction which integrates capacity allocation and energy trading in one calculation where flows on the interconnections are determined.
- In a transitional period it might be necessary to execute congestion management by both implicit and explicit auctions. This can be facilitated by allocating a fixed percentage of cross border capacities, e.g. 50%, to the regional exchange for implicit auction, and an equal part for monthly and yearly explicit auctions via the CAO.
- An Intraday Market provides an opportunity for market participants to self-adjust the balance close to real-time operations in order to reduce required balancing actions by the TSOs.
- A Balancing Market provides a vital tool for TSOs to adjust the balance in real time operations
- VPP auction is a tool to achieve more competition by offering trade of generator capacity to the market from large generation units. It should be a requirement that The SEE Regional Power Exchange offers such a trading service, as some of the incumbent generators have such a dominant market share that it might not be reduced sufficiently through integrating the national electricity markets into a competitive regional market.
• Settlement and reporting means flexibility in the reporting, settlement and billing process to handle local requirements for balance responsible parties, TSOs, and banks.
The Market Concept

The market concept is based on the constant evolution in the power market development in Europe. This has proven to be a competitive market environment where TSOs, the power exchanges, and different kinds of market participants (traders, suppliers, generators etc) have worked together to establish an efficient and liquid market place.

The key underlying concept is a physical day-ahead trading and market organization, where the market operations are carried out the day before the traded physical contracts are delivered.

This trading method is referred to as equilibrium point trading or Day Ahead Market auction trading. The price mechanism in the Day Ahead Market adjusts the flow of power across the interconnectors between the bidding areas to the available transmission capacity given by the system operators.

The day-ahead market provides a neutral reference price for the wholesale and retail markets and for power derivatives trading.

The market is based on portfolio bidding covering products for single bid, block bid and flexible bid. The total geographical regional market can be divided into bidding areas determined by predicted transmission constraints in the meshed electrical grid.

Features of the market concept

- Bids Submitted from the participants for purchase and sale as price volume pair with linear interpolation between the price points in the price calculation
- FBATC (Flow-based Available Transmission Capacity), must be provided by the TSO in each country in cooperation with the CAO (Coordinated Auction Office to be established in Montenegro, ref More info to be added in the final report…).

FBATC is maybe a better term to use as the flow-based method will be applied. Whether it is implicit or explicit auction, the TSOs in cooperation with the CAO will have to calculate available capacities for these auctions.

- Cross Border Trade, facilitated by day-ahead implicit auction and longer term explicit auctions.
- Congestion Management, integrated in the price calculation
- Balance Responsible Party, agreement to control the participant’s balance within each bidding area defined by the TSOs.
- Reporting and Settlement, can be handled centrally or locally
- Inter-Coupling or Market Coupling, coupling with another regional or national market by the exchange of Net Export Curves
Recommended Market Model for SEE

The recommended market model for the SEE regional market is the Day Ahead Market concept as discussed in this report.

The key underlying concept is the physical Day-Ahead market. In the Day-Ahead Market hourly power contracts are traded daily for physical delivery the next day 24-hour period. The Day-Ahead Market handles bids for purchase and sale of power contracts of one hour duration in the defined bidding areas in the region. The price is determined as the balance between the bids from all market participants at the intersection point between the accumulated market supply and demand curves.

The market model supports cross border trade by integrating capacity allocation and energy trading in an implicit auction. Thereby the market model set a framework adding services to both the TSOs and the market participants in the region. By using a regional exchange with these features all parties can operate more efficiently an hourly portfolio and doing this with less resources and costs. With one active trading period a day the whole portfolio for the next 24 hours will be determined. This will be an efficient tool for the participants to balance their individual portfolio and hence manage risk.

It means that the buyers and the sellers in the regional electricity market benefit automatically from cross border exchange without the need to explicitly buy the required transmission capacity. Advantages of this mechanism are to maximize the total economic surplus of all participants and adjust prices across the national borders.

Compared to explicit auction of transmission capacities, the market model with implicit auction offers advantages to the participants and is recognized as the best platform for building liquidity in a regional market.

The participants trading will generate a common regional physical market for the countries involved and will define a common market clearing price.

The common market clearing price (system price index) can be used as a reference for medium and long-term physical and financial electricity contracts. The trade of such contracts should be offered to the market participants by the SEE Regional Power Exchange when confidence is established in the price formation of such an index.

Legal and Formal Requirements

The participants in the region will be given access to the regional exchange through formal agreements including an acceptance of the book of rules, as well as technical access to the market systems through a technical interface provided by the exchange.

All participants who meet the legal and formal requirements set by the power exchange and the TSO can access the regional Day Ahead Market. The formal requirements will be such as agreements with the TSO for establishing a trading HUB and collection of meter values in the area.

As far as the exchange is concerned, the participants will have to accept the book of rules, sign the participant agreement and to document an approved bank account with the required collateral.
Trading on the regional exchange will also require that the market participants have a balancing agreement with the respective transmission system operator or through a balance responsible party for each bidding area the participants are actively buying/selling. Such an agreement will regulate the compensation requested for having an unbalance in the real-time operation by each balancing party.

**Business Processes**

The market model will be managed by the regional exchange operating the centralized tasks for the regional market. In each national market, a branch office or an already established national power exchange could support the regional exchange by performing tasks i.e. training national participants, marketing, collecting bids, and settlement of trade.

The business process in the figure below is an example with defined local operations. A regional exchange should include the flexibility in business processes and in the IT-infrastructure to facilitate various degrees of local operations. This can be required due to local legislation, local bank infrastructure and requirements from the local TSO.

Business process example:

Local Clearing and Bank Services: The business solution proposed is opening for local clearing and bank services both for a branch office and for a national exchange. It is important that both the business process and the IT-infrastructure are flexible in this respect to handle local legislation and currency.
Local Market Operation: Local market operations include handling of all functions that will integrate directly with the participants, TSO and local authorities. It is vital that these functions are facilitated by the regional exchange due to different languages, currencies and local legislations.

Regional Market Operation: Regional market operations cover all the common operations required to build the regional exchange, market liquidity and establishment of market framework for further business development. The regional operation will deliver services to branch offices and/or national exchanges after individual agreements.

Regional market operation and business processes are based on an agreed harmonized market framework.

**TSO and Balance Responsible Party**

The TSO and the Balance Responsible Party are integrating with the regional exchange directly or through the national exchange. The TSO is submitting the available transmission capacity (flow-based) and is receiving the flow and participants schedules, both individual values as well as aggregated values. The TSO will use these values for planning the daily hour by hour operation.

**Obstacles**

The proposed market model is dependent on support and commitment in the industry and stable framework set by the authorities. It is the market participant by using the market services that will build liquidity. This means that the regional exchange must be attractive to all participants by adding value, saving cost and thereby open for new services. Market evolution is an important activity and this process must be based on local and regional requirements.

Frameworks that can prevent the success of the proposed solution for the SEE market: No TSO involvement in the SEE Regional Power Exchange.

Phase 1 operation of the SEE Regional Power Exchange will be focused on physical markets as day-ahead and balancing markets which are both very closely linked to TSOs system operations. Strong involvements from TSOs in the SEE region are therefore seen as a precondition for the success of a SEE regional exchange.

- Low level integration and agreements between the TSOs and the regional exchange
- Lack of harmonization of rules for market operation can lead to market distortions and prevent the necessary build up of confidence in the system price index
- High investments and operational costs for the regional exchange.

Securing financial viability of the SEE Regional Power Exchange is vital to attract the necessary investments required to launch and operate the regional exchange.

Eligible customers and suppliers remain with “their” generator and undermine the liquidity in the open market.

The different obstacles for a successful market opening are defined as part of task 2 of this project.
**Day-ahead market**

**Market Harmonization Parameters**

The following market harmonization features are required to facilitate the market model. With a centralized solution these features will be harmonized automatically in the configuration of the market model. With a decentralized or partly decentralized solution these features have to be agreed.

- Operational Time zone for the PX
- Timeline for the required market operations
- Rules for handling daylight saving time
- Gate closure
- Master currency
- Upper and Lower price limit for bidding (these are technical limits not regulatory price ceilings/floors)
- Allocation of transmission capacity for the interconnections made available to the power exchange

**Areas**

In the market model the regional market will initially be configured with the defined network topology as fixed bidding areas.

An area in the market model can be a whole country or a part of a country. This means that a country can be split in two or several bidding areas if permanent grid constraints require this.

**Products**

The following products are normally defined in a Day Ahead Market:

- Single bid
- Block bid
- Flexible bid

In a second phase of the SEE Regional Power Exchange development, the trade in forward products should be offered. This can be physical contracts initially, and at later stage financial contracts with the SEE Regional Power Exchange day-ahead index as a reference price.
Bidding process

Bids are not related to any specific physical resource. All bids are related to a defined bidding area by a defined trading HUB. All bids have the same priority.

The single bid must be monotonously increasing. Each price must be higher than the previous price. The first bid price must be equal to the minimum price limit, and the last bid price must be equal to the maximum price limit.

The block bid for sale or purchase shall contain the same quantity for several hours. The sale bid will contain a price that indicates that if the average market price over the period (block) is lower than this level, the bid is not accepted. The purchase bid will contain a price that indicates the maximum price the purchaser is willing to pay. If the average market price in the period (block) is higher than this price, the bid is not accepted.

The flexible bid is relevant in potential peak-load hours, where power shortages cause high prices. Flexible bids are available for power sales only. Flexible bids consist of a price and a volume; hour is not specified in the bid. The price indicates the lowest sell price, and if any hourly market price exceeds the bid price, the flexible bid will be accepted in the hour with highest price.

ATC allocated to the SEE Regional Power Exchange

This information shall be provided by the TSO for each interconnection. The ATC made available to the SEE Regional Power Exchange for implicit auction will be specified for each direction between the bidding areas.

Features of the implicit auction:

- Participants in DAM represent both the demand side and supply side
- Maximum utilization of available capacity on interconnections can only be achieved by using implicit auction.
- Implicit auction include netting of trade contracts. It is the netted contract volume that determines whether the transmission capacity is fully utilized, not the gross volumes.
- Implicit auction will always lead to contractual flows in direction towards high price area.
- Negative impact of bilateral contracts in the opposite direction is reduced through increased capacity in the correct direction.
- The principle of “use it or loose it” may be applied. This means that capacity rights not used should be given to the day-ahead market.

Price determination

All the accepted bids are used in the price calculation. The price calculation will follow directly after the market gate closing time.

All the market parameters and the bids for each of the 24 hours determine the market clearing price, the area prices, total sale and purchase volumes and each participant's schedules.
System price

All bids will be added to an accumulated curve for purchase and for sale. The intersection of these curves will define the equilibrium price where the purchase and sale balance. This price is the unconstrained Market Clearing Price (MCP) and will be the official reference price for all traded contracts in the auction in case of no congestion. The MCP will be calculated for each hour and also published as an un-weighted average price for the 24 hours day-ahead market.

Area price

If the transmission capacity between bid areas for the Day Ahead contracts is not sufficient, congestion management in the implicit auction will be performed in the defined meshed network. If congestion is detected between any areas, the price calculation will continue and compute local prices to relieve detected congestions.

Market reporting

When the price calculation has been conducted, the regional market operator publishes the results.

Automatically the market model extracts the necessary participant information (electronic address, etc) and transmits the prices, the total sale and purchase volumes, and the schedules to the participants.

The prices and the individual schedules will be published to the participants. The general prices and market turnover is public, while the individual schedules only are sent to the individual participant.

Participants traded schedules will be accumulated by the regional exchange per Balance Responsible Party and reported to the Balance Responsible Party and to the TSOs. The Balance Responsible Party and the TSOs will get the individual and the accumulated values. Each participant will get his own schedule only.

The TSOs will also get an exchange report for the flow on each interconnection

Settlement, billing and collaterals

The market model will include a settlement process. The settlement process will read the participants schedules, prices and configuration data and perform a central settlement calculation. Based on this calculation the model will open for a decentralized reporting, billing and credit checking process.

The primary tasks of the settlement process are:

- Calculate amounts to be transferred between the Market Operator and the members, including all trades, fees and VAT.
- Calculate security requirements.
- Generate and distribute settlement details and invoices that specify in detail the volumes, amounts and fees of each member.
- Generate result files to be used for clearing services.
- Store information from the settlement process for archiving and auditing requirements.
- Interface to a bank

The market model will keep all required settlement data for audit trail and as long as required for storing of financial data.

Other market services that can be integrated with a Day Ahead market and that will add value to the participants responsible for power deliveries in a region.

**Intraday Market**

An intraday market provides a service to market participants to adjust their balance before the operational hour. This will reduce the balancing actions to be carried out by the system operator in real time.

Intraday market can be used to re-balance a portfolio:

- If there is a deviation between predicted forecasts and current loads
- If there is a technical event causing an imbalance after the Day Ahead Market is closed.
- To avoid paying a high penalty for having an imbalance in the real time balancing market

For a regional power exchange the intraday market should include cross border trade. This will allow enhanced competition in the balancing market (reference made to Regulation 1228/2003).

**VPP Auction**

When purchasing a Virtual Power Plant (VPP) capacity, the buyer has a right, but not an obligation to purchase power at a fixed price. The company that buys VPP capacity obtains the right to deliver power as if the company owned a power plant. The power plant is virtual because the producer company still owns the plant and is responsible for the actual power supply.

The purchase of VPP capacity represents a supplement to the purchase of power on power exchanges or from OTC suppliers.

The VPP capacity is sold for predetermined periods at an "option price". The option price is set in an auction prior to the period. For each hourly period in which the option is exercised, a pre-determined fixed "energy price" is paid for the actual quantity of power sold. The total payment for the use of the virtual power plant thus consists of an option price plus an energy price.

The VPP auction will reduce the dominance of large incumbents and open up the power market for increased competition.

Since the market concentration in the majority of SEE countries is too high to secure sufficient competition, it should be a requirement when new countries are added to the regional market that VPP auctions are carried out reducing the HH index to an acceptable level.
**Market Information**

All relevant market information must be available to all market participants at the same time. The regional power exchange in cooperation with system operators, generators and other power industry associated companies, collects and distributes price sensitive market information based on the following principles:

- The information comprises data from events that can influence prices.
- The information shall be aggregated and be presented in a way for everybody to read and understand. For the SEE Regional Power Exchange this might mean that distribution of market information must be published in both the chosen official business language and also the local language.
- The information must be distributed at the same time and with same method to all participants.

**Market Surveillance**

To build a trust in the market model and the regional power exchange and to develop a good functioning power market in terms of size, liquidity and transparency, the participants must have confidence in the market's price mechanism, its integrity and the market information transparency.

Market surveillance has an important role in establishing and maintaining this confidence and integrity by having a strong and visible presence in the market.

Market surveillance continuously monitors the market conduct of trading participants, and investigates possible breaches of the trading rules or applicable laws.

The regional exchange the SEE Regional Power Exchange will be under the jurisdiction of the country of location. Market surveillance issues reported to the national authorities of location should therefore be discussed in a formal forum where regulators from all member countries are participating.

**Inter-Regional Market Coupling**

The market model, market management and the IT-Infrastructure should facilitate an Inter-Regional market coupling to utilize the transmission capacity between neighboring regional exchanges.

The following figure describes the concept.
Business Process and Harmonization for Inter-regional Operation

The business process for inter-regional market coupling is based on exchange of bids defined as Net Export Curves (NEC) and the individual block bids.

The following market harmonization rules are required to facilitate the inter-regional market coupling:

- Choice of time zone
- Rules for handling daylight saving time
- Gate closure
- Master currency
- Upper and Lower price limit for bidding
- Decimals represented in transmission capacity and flows on the interconnections

Any deviation from these rules can create price differences in the market result.

The business process is based on one common calculation of the flow between the regions and local calculation of prices and participants schedules.
**Real-time Balancing Market**

The System Operator is responsible for balancing the supply and demand in real-time, by keeping the frequency within acceptable deviation from the set point of 50Hz. In order to manage the balancing, the System Operator will call upon various ancillary services offered by the market participants. These ancillary services are made available to the system operator by either contractual obligations or through organized markets for these services.

Initially, only tertiary response will be procured in an organized market. Tertiary response services are balancing services that the system operator can use to rebalance the system from 5 minutes ahead and up to the end of the day. This market is called the Real-Time Balancing Market (RTBM).

Primary and secondary response services are initially made available to the system operator through long-term contracts. However, in the future organized markets may be set up for these services.

The Real Time Balancing system solution shall allow for market solutions for procurement of additional ancillary services apart from RTBM.

**Participation in the RTBM**

The RTBM shall in principle be available for all market participants – including demand side assets - that comply with the rules for the market. The requirements for participation in the RTBM shall include, but not be limited to:

- Balancing services shall be associated with physical facilities for generation or consumption of electricity.
- The facilities shall be properly metered
- The facility operator shall react and comply with the dispatch instructions submitted by central dispatcher (the System Operator) by either automated dispatch or manual dispatch as specified later in this document.

**System Operation**

The principles of operation of the system by the System Operator are:

- The System Operator may prepare total system load forecast on a daily basis or receive load forecasts from Distributing Companies.
- The System Operator will receive the market participant’s balanced schedules from Day-Ahead market schedules.
- The System Operator will receive all import/export schedules.
- The System Operator will receive notifications of physical bilateral contract schedules from the market participants
- The System Operator will operate the RTBM for balancing services
- The System Operator will have contracts for access to all other required ancillary services.
• In real-time, the System Operator will monitor the system frequency. In case of deviation from set point, the system operator will use primary or secondary reserves to rebalance the system. If this is not sufficient, and in order to free primary and secondary reserves, the System Operator will start dispatching balancing power from the RTBM to balance the market.

• The System Operator is responsible for ensuring that the total capacity reserve at any time is within the limits defined in the system operation procedures.

Bid structure

The System Operator operates the RTBM – the purpose of which is to create a stack of generation and demand side offers to increase or decrease their energy to the market as the System Operator sees necessary to balance the market in real-time.

The Real-Time Balancing Market is open each day after the Day-Ahead market is closed and the DAM prices and schedules have been published to the market participants. The market participants will at that time know their energy schedules for each facility for the next day, and can determine the balancing power available to be offered to the RTBM.

The market participants (generation and demand side) submit an upward regulation offer (price/MW and volume in MW) and a downward regulation offer for each physical facility for each hour of the following day. The upward and downward offers may have different prices per unit.

The offer prices are related to the spot-price; in other words a decrement price reflects the price reduction relative to the spot price a participant is willing to reduce his generation for; and the increment price an participant is willing to increment his generation for (similar for load). See illustration below.

The offers for increments and decrements of generation and load are submitted to the System Operator though the RTBM Bid Tool.

The bids are arranged in merit order of price.

The RTBM participants will, as part of their registration process, submit information about the physical properties of the assets – such as ramp rates, run times, no-run costs etc.

The System Operator will use an automated dispatch optimization tool or a decision support tool to dispatch the assets it needs for real-time balancing. The automated dispatch optimization tool will use a computerized algorithm that will find the optimal selection of regulation dispatches whereas the decision support tool will provide to the human operator sufficient information (like the bid stack and asset parameters) in order to make the optimal selection of regulation dispatches.

1.1.¹ Note that the offers to the BM is facility oriented – as opposed to the portfolio oriented Day-Ahead market. This implies that the market participants shall also register operational and cost related facility data to the System operator.
Real-Time Market Pricing methodologies

Real-Time market pricing can be calculated in a number of ways, and the various markets worldwide have different methodologies. Two examples are presented below:

The single-price method:

In the single-price method only one real time price is defined for each hour. The price is defined as follows:

- In hours with only upward regulation the real time price is equal to the highest offer called to dispatch.
- In hours with only downward regulation the real time price is equal to the lowest offer called to dispatch.
- In hours with both upward and downward regulation the predominant direction of the regulation defines if it is upward or downward.
- If there is no regulation within the hour the real time price is equal to the spot price.

The two-price method:

- There are two prices, one for upward and one for downward regulation for each hour.
- In hours with only downward regulation the upward regulation price is defined to be the spot price or any other reference price if there is no spot market implemented.
- In hours with only upward regulation the downward regulation price is defined to be the spot price.
- If no regulation within the hour both upward and downward real time prices are equal to the spot price.
- Pricing of imbalances is based on the real time prices.

Pricing and Calculation of Imbalances

When metered data are processed imbalances are calculated. The imbalance for an hour is the difference between contracted schedules and actual metered volumes.

If the System Operator can manage to rebalance the system within an hour using the primary and secondary ancillary services, the System Operator will not need to dispatch any resources from the RTBM. The Real-Time Price will then be set equal to the Day-Ahead spot price, and there will be no imbalance settlement for the market participants. There is, however, a cost of using these primary and secondary resources incurred by the System Operator, and recovery of this cost will be socialized through the System Operation Tariff.

If the System Operator needs to call upon the RTBM resources to balance the market, the Real-Time price(s) will be calculated as the marginal price(s) of the RTBM.

Imbalances may be positive or negative. Positive imbalance means actual resources are more than the commitments for the specific hour. Negative imbalance means that actual resources are less than commitments for the specific hour.
Cost of imbalance in markets with one real time price:

The participants are credited and debited based on the same Real-Time Price. Negative imbalances are charged for and positive imbalances are credited. Imbalances may represent a profit or a loss. This method is simple and the risk for losses is assumed to be sufficient financial incentive for market participants to carefully balance their schedules.

Costs of imbalances in markets with two real time prices:

The general rule is that participants are for both positive and negative imbalances credited and debited for the less favorable of the two prices. However, if the imbalances is “helping the system” i.e. in the same direction as the total system requires, the participant is charged and credited based on the spot price. This means the participant has no losses or profit on the imbalances compared to trade in perfect balance in the spot market. This model for pricing of imbalances and implies a stronger financial incentive to operate with balanced schedules and are implemented in most of the restructured markets.

In principle, the market participants shall be encouraged by the real-time imbalance penalties to minimize the imbalances they impose onto the system. They will mainly use the Day-Ahead market to trade themselves into balance, and will be more cautious in their real-time facility operations if they are aware of the imbalance penalties.

On the other hand, if the imbalance penalties are severe, some participants, especially smaller auto-generators, renewables with uncontrollable generation and demand side may not be willing to take the risk of the severe penalties of imbalances, and will redraw from the market and become self-scheduled participants.

The RTBM system solution shall support a Real-Time Pricing mechanism that gives the market participants the right incentive to avoid imposing imbalances in the real-time market, but not impose so strict penalties for imbalances that it discourages the market participants from participating in the market.

Capacity Reserve market.

There are set predetermined minimum requirements for capacity reserves in SEE. These requirements may change over time and location and shall be system parameter in the Balancing Mechanism.

The total aggregated stack of offers to the RTBM is in effect the available Capacity Reserve market, since the stack represents the total capacity that the market participants makes available to the system at any time.

However, it is likely that the total stack of RTBM offers does not fulfill the minimum reserve requirements. The reason is that market participants has not direct incentives for holding capacity back from the energy markets (Day-Ahead and bilateral) in order to offer them into the RTBM. The offers to the RTBM will be for extra “top-up” energy that is not fuel efficient, and these offers will typically drive the Real-Time prices up. On the demand side, there is no direct incentive for the consumer to enter “stand-by” offers to reduce load.

In order to encourage suppliers and demand to offer sufficient capacity into the RTBM, incentive arrangements such as a capacity availability payment have to be put in place.
This capacity reserve payment can be structured several ways. Two structures are presented below as examples:

1. A regulated availability payment price. The System Operator will set the regulated price to a level that ensures sufficient incentives for participating in the RTBM, and will adjust the price at a regular interval.

2. A market determined availability payment price. In this case, market participants will submit bids for their willingness to offer capacity into the RTBM. The System Operator will pick the cheapest bids until the capacity reserve requirement is met. The availability payment price is set to the equal to the last bid accepted. This selection process could be on an hourly basis, or for longer terms – for example weekly or monthly.

The RTBM system solution shall support a capacity availability payment arrangement, which provides incentives for ensuring a sufficient capacity reserve.

**Financial Market**

One of the inherent and unavoidable features of any physical electricity market design are unpredictable and volatile prices. Introduction of a regional physical day-ahead market will presumably lead to increased volatility in both the DAM and also in the short-term bilateral market, since market participants is expected to arbitrage between these two markets. In this report, the focus is on this combined wholesale market and the short-term wholesale prices emerging from those.

It is at this stage important to note that wholesale electricity is traded through various methods and at various price determinations in SEE:

- Long-term bilateral contracts which today represents the bulk of the wholesale market is subject to regulated and/or contracted prices and do not represent much uncertainty (volatility).

- Short-term trading; through bilateral contracts and in near future, through DAM; represents much higher volatility, since these prices are not to (or should not) be regulated and are typically derived from the equilibrium between supply and demand at any moment of time. Both available supply and demand will vary significantly over time and thus introduce high volatility.

- Real-time “trading”. In this context real-time “trading” is represented by the balancing mechanism, where real-time imbalances are in effect “sold” and “procured” by market participants using a balancing power market and also the connected imbalance pricing.

The focus in this chapter is on the short-term wholesale market and the prices derived from that market. As mentioned before, it is expected that even if there are concurrent bilateral and PX short-term markets, the prices in those markets should be closely correlated. We shall

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1.2 It must be expected that traders will take positions in both the bilateral and PX short-term markets and look for best trading opportunities in both. This will lead to convergence of prices in these markets.

1.3 Actually the supply/demand equilibrium for each trading interval one day ahead (or longer for bilateral contracts).
therefore refer to the short-term hourly price as the Market Clearing Price (MCP), representing the price that is derived from the equilibrium between supply and demand in the short-term markets.

The purpose of an SEE Electricity Derivatives Market shall therefore be to provide an “instrument” or “tool” to “hedge” (i.e. offset risk) against the MCP price volatility derived from the PX and short-term bilateral markets.

The most effective and common arrangement for handling price risk in electricity spot markets is electricity derivatives contracts markets.

The term “derivative” is used in the context of commodities trading as a financial product (contract) that derives its value (i.e. its payoff) from the price of an underlying commodity. In this context, the “derivatives” in the SEE market will derive their values from the PX’s Market Clearing Price. In the chapter for the Regional market design the topics of market splitting and zonal prices has been presented. That means that there typically will be several and potentially very different clearing prices in the various SEE countries. Ideally one may develop different electricity derivatives contract for each of these countries, but that may dilute the liquidity and increase the complexity of the SEE derivatives market and should at least initially be avoided. We therefore assume a single reference price that typically is the so-called “unconstrained market clearing price” (UMCP) for the entire SEE market. It is important to not confuse physical forwards contracts with financial derivatives contracts.

- Physical forwards contracts are simply agreements of a future delivery of some commodity (e.g. electricity) at volume, price and delivery terms agreed in advance. As the name indicates, this implies obligation of delivery of the commodity. All long-term and short-term bilateral contracts traded in SEE and other places can be regarded physical forward contracts. Day-ahead market contracts as stipulated in the PX model proposed by the Consultants should also in this context be regarded as physical forwards (one day ahead).

- Financial derivatives contracts, on the other hand, do not imply physical delivery of the commodity, but rather a cash exchange based on the price/cost of the underlying commodity. The term “delivery” and “delivery period” for a financial derivative is therefore somewhat misleading, as it refers to the delivery of the underlying commodity and not the derivative itself (unless one want to think of “delivery” of cash over the settlement period).

A physical forward is therefore a guarantee for delivery of the commodity, while a financial Forward does not guarantee the physical commodity, but rather a guarantee on the price for the commodity – whichever way the buyer obtains the commodity. This difference is important with respect to e.g. scheduling and Clearing.

One working assumption is that most participants in the SEE electricity supply and distribution industry are risk averse in the sense they will prefer some degree of price security and are willing to pay a (small) premium to avoid high volatility.

The Consultants therefore assume that as the SEE electricity market becomes more competitive and efficient, one must expect:

- increase in price uncertainty to short term electricity trading, which will introduce financial risk for the market participants
• increased requirement for financial instruments to handle these risks, and
• increased requirement for a derivative market in SEE.

It is important to keep in mind the discussions provided in this report are mostly relevant in a scenario with an operating PX similar to the model proposed by the Consultants.

Derivatives will enable the SEE regional market participants to manage the price risk, which is the second largest risk in electricity business. They will be able to hedge against price risks as far as needed into the future. Along with derivatives the third largest risk – the counterpart risk – becomes manageable through the establishment of a clearing solution. Clearing services will reduce this risk to a minimum and allow the participants to concentrate on efficiency – which again results in cost reduction and optimized resource usage.

**Organization of a Regional Power Exchange**

**The Power Exchange Concept**

The regional power exchange organization must have flexibility and a structure to facilitate cooperation across national borders. The exchange will be the body for development of the regional market concept. This requires an organization that is able to include in the business process national features and requirements adapted and harmonized to the regional concept. It is vital that regional agreements related to ownership, legal framework, localization and harmonization issues are developed in close cooperation between all the parties involved.
**Organization and Supporting Roles**

Ownership: In the first phase of the SEE Regional Power Exchange establishment it is vital that the TSOs in the region play an active part in the exchange business processes. The SEE Regional Power Exchange business processes will provide services for the TSOs and the TSOs will define framework for the exchange. The interest for both parties can best be executed by the TSOs taking an equity share and be members of the board. This should be an option for all the TSOs in the region.

Ownership should also be open for national PXs in the region to ensure that framework for the SEE Regional Power Exchange is supported by all parties.

Strategic Partner: In the starting phase it will be recommended that an experienced market operator with competence regarding the market concept, market operation and market IT-Infrastructure is playing an active part in the process. It will shorten the time to market to have this support from an experienced partner.

Facility Management Service Provider: The FM service provider can deliver IT-Infrastructure and other services as distributing market information, training and technical IT-Infrastructure development in the region.

It will be an advantage for the regional market development that this provider is located in the region. This will build competence and know how in the region and set a good platform for market evolution and development.

Coordinated Auction Office (CAO): Allocation of capacity for the exchange can be provided by an “Auction Office” as an entity running and coordinating services for the TSOs in the area. More to be added in final report.

**Ownership**

The SEE Regional Exchange should be organized in a flexible manner, which means that participating countries can choose the degree of decentralization from a branch office to a more decentralized link with the regional entity.

The question could be raised if a branch office establishment in each participating national market is necessary. As an example could be used the expanding regional reach of the German power exchange EEX, where this exchange offers DAM services to both Austria and Switzerland without a local presence represented by a branch office or a similar service.

This is, however, an exchange operation that does not offer a market coupling or market splitting implicit auction of border capacities. The Austrian electricity market is fully integrated in the German bidding area, and no area price for Austria is ever quoted. In the case of Switzerland a totally separated DAM operation and a separate price (Swissix) is quoted on an hourly basis.

In the Nordic market, Nord Pool Spot AS has established a subsidiary both in Finland and Sweden and a branch office operation in Denmark to take care of various activities linked to each national market.
For the trilateral market coupling between France, Belgium and the Netherlands each national market is being served by the national power exchanges Powernext, BelPex and APX respectively.

Another example is the regional operation for the Iberian electricity market. The operation of the market has been divided between Portugal and Spain. A regional day-ahead market with implicit auction/market splitting is operated by Spain, while the trade in electricity derivatives is executed from Portugal. This ensures a local presence in both countries.

The SEE national markets are characterized by:
- Local regulatory framework to hold and operate a license
- Different languages
- Different degrees of maturity with reference to market development

It is therefore strongly recommended by the Consultant that at least a branch office is established in each national market performing as a minimum the following services:

- Customer support in the bidding process
- Arrange required training seminars in the national language
- Sales and marketing of power exchange services
- Settlement of DA contracts in cooperation with local banks
- Providing all relevant market information in the national languages securing full transparency
The flexibility with respect to participation in the regional exchange is illustrated in the figure above.

Regarding ownership it must be underlined that the regional exchange will in its first mode of operation be covering only the physical short-term markets. This will be very closely linked to the TSOs real-time market operation.

It will be an advantage for the market development that the TSOs play an active part in setting the required framework. It is therefore recommended that the TSOs can execute this both by a direct ownership in the exchange and also as an active member on the board.

There may be national markets that only require a small office dealing with market operations to maintain the required minimum communication with the national market participants. This alternative is referred to as “centralized operation”.

It is assumed that most national market will require some activities allocated to the national level. This alternative is referred to as “partly de-centralized operations”.

In the fully de-centralized operation all activities that are possible to de-centralize are moved to the national power exchange.

It is at this stage assumed that most of the national markets within the SEE Regional Power Exchange region will operate as decentralized markets. The national markets will in this alternative to a large extent operate as an independent national power exchange and interface the SEE Regional Power Exchange only in issues necessary to form one common regional market. This alternative is referred to as “de-centralized operations”.
There are some tasks that must be carried out on regional level or for practical reasons should be carried out on regional level. These activities are:

- Operation of the trade system: Calculation of unconstrained regional market clearing price and area prices in case of congestion and calculation of trade schedules for all regional participants.

Tasks that can be de-centralized are mainly:

- Marketing on national levels
- Support and service to national participants
- Monitoring bid collections and validation of bids for both DAM and ID
- Dispute Management for trade notifications
- Financial settlement of traded contracts and risk management (collaterals)
- Training of participants
- Entry of new participants
- Exit of participants

**Centralized Market Operations**

In this alternative no national organization may be required. All communication on market issues will be between the regional power exchange and national market participants. It is assumed that national authorities and the regional power exchange in most cases will prefer to establish a small unit (a branch office) to take care of marketing, communication with local authorities and general distribution of information.

For all participants the cash flow will be between the participants’ accounts and an account owned by the regional power exchange.

**Partly De-centralized Market Operations**

Partly de-centralization can include de-centralization of all tasks that can be characterized as service tasks and tasks that do not require any activities during holidays or stand-by arrangements.

The main tasks that remain as centralized operations are spot price calculations, operation of the trade system, and operation of the settlement system.

Also in this system all cash flow will be between the participants’ accounts and an account owned by the regional power exchange.

The present Nord Pool Model may be characterized as a “light partially de-centralized” model.

**De-centralized Market Operations:**

In de-centralized market operations the participants will communicate with the national power exchange in all daily operations. Monitoring of bids, control of trade notification, risk
management and financial settlement of physical contracts will be carried out by the national power exchange.

The national power exchange must operate on all calendar days and have stand by arrangements.

The cash flow in the settlement will in this case probably be between the participants’ accounts and an account owned by the national power exchange in cooperation with a local bank.

There will be an additional settlement between the national power exchange and the regional power exchange that involve the net trade surplus/deficit between the national power exchange and the remaining part of the regional market. Hence in a de-centralized operation the risk management (calculation of collaterals, invoicing, settlement etc.) can be carried out separately for each country.

**Legal infrastructure**

The figure below is displaying the required legal infrastructure.

The legal infrastructure will be harmonized and equal for all market participants, as illustrated in the figure below:

With reference to the illustration above, the main agreements for market operation are:

- Participation Agreement
- the SEE Regional Power Exchange - National PX Agreements
- the SEE Regional Power Exchange – TSO Agreement
National PX - TSOs Agreement

The Participation Agreement

All market participants within SEE Regional Power Exchange area shall trade on equal terms. If there are minor differences in the rules between the national markets these differences must be transparent and included in attachments to the regional spot rules.

The agreement includes:

- All detailed activities related to bidding, price determination, verification of trade schedules, and submission of trade schedules to TSOs.
- Commitments by the parties related to collections and distribution of neutral market information.
- Time line for all settlement activities of spot contracts and requirements regarding security amounts and accepted collateral types.

The above rules are often included in one agreement and referred to as Accession Agreement, Participation Agreement or The Rule Book for Spot.

The SEE Regional Power Exchange – National PX Agreements

These agreements will vary depending on the degree of integration. In the most de-centralized alternative the agreement will include nearly all issues related to trade and financial settlement:

- Careful specification of the share of responsibility between the SEE Regional Power Exchange and the national PX.

Full de-centralization will require a financial settlement between the national power exchanges and the regional power exchange. Rules for this settlement have to be defined in the agreement:

- Format for bid-data
- Procedures and timeline for submission of bid-data

The only process that will be fully centralized in all forms for integration is the process of price determination, calculation of trade schedules and distribution of neutral market information.

The SEE Regional Power Exchange – TSOs Agreement and the PX-TSO Agreement

The two agreements will cover much the same issues and may be replaced with one agreement between the parties: the SEE Regional Power Exchange, National PX, TSOs.

The agreements regulate all mutual responsibilities and information flow between the SEE Regional Power Exchange and the respective TSOs. One identical agreement towards all interconnected TSOs is to be preferred. However, there will probably be required to diversify on some issues. This can be made in attachments for each TSO concerned incorporated in the
agreement. Only one agreement with attachments for each TSO makes a transparent agreement where diversified rules are easy detected for all.

For all TSOs the agreement must include:

- Daily reports to the SEE Regional Power Exchange/NatPXs on allocation of capacity on interconnections to be used for implicit auction. In the first phase of operation of the SEE Regional Power Exchange, only a part of the available capacity might be given to the exchanges for implicit auction, the remainder part might be offered on monthly and yearly capacity contracts for explicit auctioning.
- Reports to the TSOs on traded spot contracts.
- Acceptance of the principle of self dispatch of traded spot contracts.

The SEE Regional Power Exchange should serve as a platform for collection and distribution of relevant neutral market information. TSOs are important sources for such information. The agreement must include the parties’ commitments in distribution of information.

**Principles for collection and distribution of information**

Acceptance by TSO to consider traded spot contracts as firm contracts that cannot be changed or curtailed after the trade is terminated. This means that contracts that is not delivered in the internal national market is handled as imbalances by TSOs. Non-delivery caused by default on interconnections is managed by the TSOs involved in their respective balancing mechanisms.

Management of imbalances caused by default in trade operations made at the SEE Regional Power Exchange.

**Market Coupling Agreement**

The regional power exchange the SEE Regional Power Exchange will interface other independent regional or national market in the same manner as between the EEX and Nord Pool.

**Market Operation**

Market operation is the daily operations and routines to determine the day-ahead market and settle the market result. This includes interaction with all participants, balance responsible parties, TSOs, clearing services and banks. When the market is closing its operation on a trading day all the power and economical transactions have to be settled.

Agreements and detailed daily routines have to be specified and settled.

It will be the regional exchange that will define the book of rules, daily routines and agree this with the system operators holding the different roles in the market area.

This will require detailed knowledge centrally at the SEE Regional Power Exchange to handle local agreements with the authorities and regulators in the different countries in the market area.
Even with a decentralized solution, the SEE Regional Power Exchange must set up the same framework for operation. Some of the regulatory issues can be handled locally by the local exchange. This may speed up the process.

**Interface to the TSOs**

TSOs will have a role initially clearing new participants for trade in the day-ahead market concerning meter values, agreement with a Balance Responsible Party and signing of necessary legal documents.

The interface to the TSOs will for the daily operation include the following tasks:

- The TSOs submitting available capacity on the interconnections to the power exchange.
- In the SEE region it will be set up a CAO (Coordinated Auction Office) in Montenegro, which intends to offer transfer capacities on national borders explicitly and according to a flow-based method.
- Facilitation of regional power exchange operations requires that the TSOs give some or all of the BC to the SEE Regional Power Exchange. The split of BC between the CAO and the SEE Regional Power Exchange should therefore be part of the interface arrangement with each TSO.
- The power exchange delivering data for flow on the interconnections.
- The participants’ traded schedules.
- The exchange of data will normally be based on xml-files and structured according to the ETSO standard.

**Settlement and Billing**

This is the final settling of all the trades in the regional day-ahead market. The settlement with calculation of the traded amounts and fees is a daily operation, while invoicing and billing should be open for configuration for a certain period.

To reduce requirements for collaterals, invoicing both for power and fees should be done on all open banking days.

Settlement and billing is a central operation calculating all the settlement data, while reporting, invoicing and credit checking can be a central or local operation.

Invoicing and billing require an electronic interface to the bank infrastructure sending a file with all billing instructions and receiving from the bank a file with the account balance.

**Centralized**

For this solution all settlement operations, bank interfaces and credit checking is done centrally. The regional exchange must either set up an interface to a central bank that can handle all account transactions for all currencies or set up an interface to all local banks operating with participants’ accounts in the market area. This requires that the exchange centrally holds all detailed information concerning the different local bank procedures.

**Decentralized**
Basically this will include the same set of functions, but each branch office will normally handle the local bank interface either directly or using a local clearing house.

**Transparency of relevant Market Data**

Full transparency is a required part of the market reform whatever market design is chosen. The number of participants at the power exchange, and traded volumes, can only grow if existing and potential members feel secure that all relevant market information is given to all participants at the same time and to the same cost.

As a minimum, real time access for all participants to prices, operational data, and grid maintenance information in the power market must be provided. In markets where hydro power constitutes a significant share in the energy mix, reservoir data should be provided. To further increase the transparency, frequent reports containing operational and physical market data as well as a statistical database could be developed.

To secure that relevant market information is provided to the market participants at the same time a system for short term information release must be developed. The information published in such a system is based on information provided by the system operators and the participants in each participating country to the SEE Regional Power Exchange.

All aspects regarding disclosure of information should in the case of the TSOs be regulated by a unified publication agreement between the various TSOs and the SEE Regional Power Exchange, and in the case of the market participants in the rulebook(s) for trading.

**Centralized**

For the information disclosure, it makes no significant difference whether the SEE Regional Power Exchange is built from scratch or based on existing infrastructure.

To reach all participants the information tool should be available as a Web based system of the SEE Regional Power Exchange with an interface for entering information and viewing information and data. All information must be displayed at least in English, but preferably also in the local language of the country from where the information is originated.

The rule book should address routines for information disclosure in the market

**Decentralized**

The same solution as described above.

The information disclosure procedures must be addressed and harmonized in each local PX’s rule book.

**Market Surveillance**

The market surveillance function will in principle be identical independent on choice of market design. Basically this is a centralized function operated by the regional exchange in a separate department, reporting not only to the top management of the exchange, but also to regulatory authorities in each of the member countries. The latter might require harmonization across the region and full compliance with EU directives related to market conduct.
To support the proposed market model for the day-ahead market and to develop a well functioning exchange in terms of size, liquidity and transparency, the participants must have confidence in the market's price mechanism, its integrity and the market information transparency.

Market surveillance has an important role in establishing and maintaining this confidence and integrity by having a strong and visible presence in the market. Market surveillance continuously monitors the market conduct of trading participants, and investigates possible breaches of the trading rules or applicable laws.

Centralized

The function will be operated as a separated department within the SEE Regional Power Exchange organization. In the first phase it is important to establish this function as a legal body. The objectives will be to establish the department with the required rules, procedures and most importantly; sufficient authority given by the regulators in each of the countries allowing a well-functioning market surveillance role.

Decentralized

Also for this alternative the surveillance function will be established as described above as an independent department within the central regional exchange with the same reporting requirements as for the centralized alternative.

Trade System

As previously discussed it will be vital for a regional exchange to implement a day-ahead system that in the first phase must facilitate the basic needs and have the features to adapt to future business requirements by use of configuration and system parameters. Proven technology, system modularity, parameterization and low costs is key factors that should be considered for a modern day-ahead market IT-System.

For both a branch office and a decentralized solution the trading system must hold the same functions, but implementation and functionality may differ for the two solutions.

This is an implementation were all data processing is done centrally, but includes functions that open up so local exchanges or branch offices can handle interfaces to the participants, balance responsible parties, TSOs, clearing houses and local banks.
TRANSITION PHASE: FROM REGULATED PRICES TO MARKET PRICES

Regulated Price

This is often a sensitive issue, especially in emerging economies. History shows that in many areas authorities and politicians try to keep electricity costs low through cross-subsidies although the development of the electricity business needs correct price signals and investments:

- An often used alternative is to introduce a partly exposure to market prices, i.e. some selected consumer groups are exposed to market prices while others are supplied using regulated prices.

- Sometimes the above chosen alternative is modified by allowing selected consumer groups exposed to market prices a limited access to volumes with regulated price (=cheaper) energy.

- Regulated prices can be kept low through subsidizing the expensive units through the cheaper units, e.g. through calculating an average cost of all involved units.

- In some places the electricity price is kept low through securing supply of selected consumer groups with the cheapest national units.

The overall challenge is to replace the regulated price with the market price and to fulfill the mandatory EU compliance. The political dilemma regarding issues like vulnerable customer protection and price predictability for industrial consumers visualizes this challenge.

When looking at the electricity value chain it seems inevitable to pass on the correct costs and to introduce competition to all reasonable levels of the value chain. This is the only possibility to create an environment which leads to increased efficiency and reduced costs, which again results in correct investments, further optimization of the electricity supply and consumption and increased security of supply.

As an efficient wholesale power market is characterized by competition amongst generators, price penetration to consumers, transparency and trustworthy price references, it is important to remove regulated prices.

It is also crucial to understand the difference between regulated and market price:

- Regulated price is initially calculated as cost recovery price for generation, transmission, system operation, distribution, supply and investment costs.

- Authorities, e.g. the electricity regulator, often choose to substitute selected consumer groups by deciding lower prices than actual costs for them and substituting this by higher prices than costs for other consumer groups. In some cases the electricity business did not have to collect for future investments or maintenance, thus there was/is a need for additional capital from authorities when maintenance or expansion projects become a need.
A market price – resulting from marginal pricing in the market – reflects the same cost components as in a regulated price regime.

Also in a market price based regime selected consumer groups can be substituted through favorable grid tariffs and taxes and fees. In Europe it is also known that selected industries are supplied at a special price through state-owned generation.

Important in this context is to secure that the market price determined by the market has a high enough quality, i.e. that it reflects the last used unit’s marginal costs. This can only be achieved in a market with sufficient enough competition and thus a by investors and participants accepted profit margin and efficiency rate.

The challenge although is – when trying to create conditions facilitating the quality of the price – that as many as possible of the consumers and generators should be exposed to this price. This is a strong argument against regulated prices.

**Traditional Full Supply Contracts with Regulated Price**

Traditional full supply contracts constitute an obstacle in any development towards a competitive wholesale power market. Full supply contracts expose the consumer only to the regulated price regardless of how much and when he consumes energy. He has no incentive to respond to market prices. In a region facing power supply deficit, consumers’ price elasticity and demand response should be “challenged”.

Traditional full supply contracts mainly contain four details:

- **Delivery period** \(t_0 - t_n\) as settlement period
- **Installed capacity** as maximum load (MW)
- **Accumulated energy withdrawal during the delivery period** (MWh) as settlement volume
- **Regulated energy price** (€/MWh) as settlement price

Competitive wholesale power markets are dependent on participation of consumption in the price determination, thus the inclusion of their response to prices. In addition it must be secured that both consumers and generators achieve a sufficient balance through energy trading and not through real-time operation by e.g. generators generating according to his customers consumption.

- **Balance Responsibility** – someone has to purchase consumption in advance and someone has to be economically responsible for deviations between the purchased and metered consumption in the process of imbalance settlement
- **Settlement unit** is MWh/h – this means that imbalance settlement is performed for each hour during the settlement period and not for accumulated energy generation/consumption throughout a period of time longer than one hour. This implies that contracts are also related to hourly values per hour.

Replacing traditional full supply contracts with standard fixed MW and GWh contracts and at the same time making Suppliers and Eligible Consumers Balance Responsible Parties are the first steps to be taken towards a successful wholesale market opening.
Supply Contracts and Balance Responsibility

In competitive wholesale power markets the introduction of obligatory Balance Responsibility forces eligible wholesale market participants to balance each hour of generation respective consumption with contracts. This introduces three further details to supply contracts, which have replaced the former traditional full supply contracts: imbalance per hour, price for imbalance and balance responsible party.

In the electricity value chain the Balance Responsibility changes the traditional business as follows:

- The generator can no longer follow his customers load due to the requirement having to balance his generation with contracts. The previous cost calculation with average generation costs for a longer period of time is replaced by hourly generation costs plus costs for imbalances. Normally a competitive wholesale power market will lead to generation costs being replaced by wholesale market price. Thus the generator will sell his estimated generation at market price – which with precise estimates will result in only minor imbalance costs. Alternatively the generator will schedule generation as a result of price dependent bid results from short-term markets like DAM or Intraday – also in this case a minimum imbalance potential.

- The supplier will have to take on responsibility for balancing his customers. A good consumption estimate will allow the supplier to purchase energy at market price and minimize imbalance costs. In any case the supplier will be invoiced for occurred hourly imbalances. This implies that his customers will have to accept that the supplier estimates their consumption as good as he can and passes on any imbalance costs due to wrong estimates. Or they take on the estimation themselves and thus have direct influence on the estimates' quality. A consumer can then choose whether he wants to be balance responsible or join the supplier’s balancing group. Irrespective of which case is chosen they have in common that the customers either see two different prices, one for energy and one for imbalances, or one price, which is higher than the market price due to the inclusion of the supplier’s imbalance risk.

- The consumer will – if hourly metered and defined as eligible consumer – also be defined as balance responsible. If not hourly metered his supplier will be balance responsible for him. The hourly metered consumers will be able to choose a full supply contract – thus make the supplier balance responsible – or declare themselves as wholesale market participants, thus estimate their needed energy and purchase it themselves. They can purchase the energy from any counterpart in the wholesale market. In the latter case they are balance responsible and can choose either to be the direct counterpart in the imbalance settlement or join a balancing group, where one dedicated counterpart performs the imbalance settlement with the TSO and distributes the imbalance costs between the balancing group’s members. In any case the hourly metered consumers are exposed to hourly energy costs and this creates a strong incentive to perform demand side response.

Transition Period

Exposing eligible customers 100% to market prices from day one of the wholesale market opening process will meet hindrance in most countries due to uncertain market prices and
their volatility. For this reason transitional schemes should be considered. The need for such schemes will vary across the region, because each country has different starting points.

Some countries have already taken steps to expose eligible customers to market prices. In general a transition period with steadily decreasing contract volumes supplied with regulated prices is recommended to gain acceptance among market participants.

The following two figures illustrate how this downsizing can work without jeopardizing incentives for wholesale market participants to expose themselves to the market and to enable them to respond to market prices.

Suppliers and Eligible Customers will – through this design - be supplied with a contract at regulated price from their former full supply contractors. The contract volume will be lower than their consumption.

Such contracts should be signed prior to market opening in order to provide predictability to the suppliers and eligible consumers. Suppliers will thus also be able to show tariff prices to their customers covering future periods of the transition period if parameters $t_1$, $t_2$, $t_3$ are announced. Suppliers and eligible consumers will thus have to purchase the difference between expected consumption volume and regulated price contract volume in the wholesale market.

It is also recommended to allow consumers to be able to resell the volumes contracted at regulated price. This will enable the consumers to respond on price peaks (demand side response) and will provide the TSO with potential reserves for peak load hours. This is a good solution for the Generators as well. Without resale possibility the customer will operate quite “ordinary” even during extreme peaks and his Generator has to use expensive resources (own production or purchased power) to maintain contractual supply.
Transition Period: Market and Regulated Prices; Generator

Generators will at $t_1$ have capacity available for the wholesale market since full supply contracts will be abolished and volumes sold at regulated prices are below the generation capacities. They will have incentives to develop new projects and upgrade old capacity and to sell it in the wholesale market. Reservation of import capacity to secure public supply obligations will be redundant.

In general it is recommended to replace any existing traditional full supply contracts as soon as possible with preferably base load contracts. These contracts can have the regulated price as basis. Base load means that the load profile of the consumer has to be filled up with market price based contracts. The consumer will thus need access to the wholesale market or an additional contract with a supplier in order to be able to balance his expected consumption with contracts. During the transition period the base load contract’s volume with regulated price has to decrease to zero and thus his exposure to market prices will increase to 100%:
The “control parameters” (t1, t2, t3 and the level of the regulated price) should be decided by national authorities. Regional consensus is not required. This approach leaves national authorities with full control over the transition period and allows a steadily increasing exposure to market prices. Customers will be motivated to adapt to market prices and prices “penetrate” from day one.

The figure below illustrates how S and EC will approach the market through increasing volumes (red) over time, building demand side at the DAM from day one. There is deliberately drawn no arrow from G to S and EC for the “free” volumes in order to stress that this demand should be bought on the open market.

Transition Period: Market and Regulated Prices; Customers increasingly exposed to market prices, and PX “operational” from day 1

Lack of unbundling of supply and production activities within incumbents makes it possible for them to offer favorable prices to their “own” customers and thus obstruct market opening. Generators will not offer “free” volumes below market price, but their owner might have different priorities. If Suppliers and Eligible Customers continue to stay “captured” for a long time and volumes do not appear on the DAM, a couple of remedies might be considered:

- Discourage S and EC from buying free market volumes from their “own” Generator. Other Generators, traders and sourcing on PX should represent their procurement options.
- Give EC a higher contractual coverage at tariff prices than the Suppliers. In this way they will prefer to exercise their eligibility in order to reduce cost. Liquidity in the wholesale market will improve.

KPIs developed under Task 5 will support the authorities in deciding if such market interventions are required.

In the SEE region a Public Procurement Law (PPL) requires that public companies issue tenders when intending to purchase electricity. The Law shall secure that public interest are protected. Questions have been raised if the PPL prevents suppliers from participating in organized markets like a Day-ahead market (DAM).

Daily purchase bids submitted to a DAM and the resulting procurement of energy is to be considered a public tender process, thus participation of suppliers must be enabled.
DAM and implicit auctions allow supply and demand to set market prices each hour in every price area (when grid congestions prevent equal prices) and thus secure correct prices in addition to setting the correct cost for congestion. Market prices will penetrate across the SEE region, bringing transparency (prices and flows) and trustworthy price references to all market participants from day one of the market opening.
ACTION PLAN

Based on the descriptions above, it is the Consultants clear recommendation that SEE has to merge to a regional electricity market producing a SEE regional reference price for energy.

The following activities are required to ensure the goal of a fully competitive wholesale market opening.

Decisions

There are a set of key decisions to be made to achieve the desired goals.

- Implementation of Balance responsibility for wholesale market participants;
- A regional market founded on a Day-ahead market with implicit auction with allocation of cross-border capacity to the market;
- Harmonisation of rules and regulations between the SEE parties;
- Removal of the traditional Full supply contracts to Suppliers and Eligible Customers;
- Transparency and equal market access to all.
- Support for the required changes and commitment to the action plan(s) for the region

The need for further harmonization

Grid tariff design (grid owners and regulation)

- Grid loss management;
- Management of energy transfer through grid zones;
- A point-of-connection tariff should be implemented for eligible wholesale market participants;
- Retail consumers should be handled through profiles related to the individual grid they are connected to, thus enabling them to change supplier. This implies that grid costs should be invoiced separately through the local grids;

Balance Responsibility (TSO and regulation)

- Regulation related to Balance Responsibility for the SEE region;
- Management of imbalances (pricing, settlement intervals and surveillance);
- Control area definition.

Metering, plans, imbalance management and transparency (TSO, regulator)

- Procedures for meter reading and data processing for wholesale market participants;
- Rules and procedures for data exchange (generation schedules = trading deadline);
• Imbalance Management (determination procedures and details, data exchange, deadlines, due dates, imbalance pricing, regional balancing power market, imbalance settlement frequency);
• Interconnection capacity determination rules (internal and external interconnections) – cross-border capacity;
• Rules for counter trade (determination of bottlenecks, handling of bottlenecks);
• Publication of market relevant data.

**Regulation (regulator, authorities)**

The regulatory authorities will need to harmonize the framework for the market participants:
• Eligible consumers and generators – the criteria should be as equal as possible;
• Unbundling – wholesale market participants need to be unbundled from monopoly parts of the company in order to avoid cross-subsidies within one company;
• Metering and settlement: a common set of guidelines and procedures for handling should be developed;
• Taxes and fees;

**Establishment of a regional market (TSO, regulation and market operator)**

• Develop the SEE reference price;
  – Set up the regional SEE reference price for energy (DAM);
  – Development of derivatives and market place for trading of derivatives;
  – Development of a clearing solution for derivatives.
• Cross-border transmission capacity between the internal SEE areas managed through implicit auctioning;
• Definition of bidding areas;
• Enable neighbouring markets and areas to participate in the SEE-market;
• Binding DAM contracts
• Enable retail competition
  – Profiling
  – Metering
  – Change of supplier procedures
  – Data reporting responsibility
  – Change of supplier cost allocation and distribution

**Market surveillance and supervision (market operator and authorities)**

• The market surveillance organization shall monitor that the electricity business is fair and trustworthy.
Market supervision shall monitor that the development of the market is satisfactory and that the mechanisms are working as planned/expected.

**Project team(s)**

The regional and competitive SEE Power Market requires a project team. A Steering committee consisting of the relevant stakeholders in the SEE Region must be established. These should then point out a project owner (organization or group), which should be given the authority to decide on the detailed implementation according to plans and envisioned targets.

The project owner will then nominate the required project team(s) to be the actual participants in the various activities needed.

The content of each activity is covered in the implementation plan.

**Implementation Plan**

The implementation plan shows the different project activities arranged in a master time plan with expected duration and dependencies.

Please refer to the attached project plan.

This is the generic action plan with an indication of when the final dates for the various tasks will have to be finished. Each participant in the regional market will need to have separate plans where the actual milestones and actions are detailed taking into consideration the local variations. To create these will be one of the initial tasks of the Implementation project.

**Dry run**

Dry run has two meanings in this context; a possibility for participants to simulate/train market participation, and also simulate different market setup scenarios.

The introduction of balancing responsibility to Suppliers and EC represents a new situation for them. Preparation through dry run is strongly recommended. During such exercises the new market participants will become familiar with load forecasting and gain experience in trading on a DAM before real operation.

The idea is to simulate a DAM through bids and offers from Generators, Suppliers, EC and Traders. Cross border capacities have to be allocated and bids/offers will decide export/import volumes.

Contracts with fixed MW/GWh have to be set up between Generators and Suppliers/ECs representing today’s contract obligations. Suppliers and EC will nominate hourly bids at the PX equal to the difference between their estimated consumption and their contractual obligations. Generators will nominate bids and offers dependant on their planned production.
In this way a merit order curve is established. Cross border trading capacities between SEE countries - allocated to the DAM - will be nominated as part of different scenarios. To simulate the effect of power exchange with “perimeter” countries, actual agreements (MW) should be represented by price independent bids in the relevant bidding area (country).

The DAM will calculate area prices, contractual flows on interconnections.

To gain experience, such simulations will be run for representative periods of time and with representative market setups to cover all relevant scenarios. The dry run period can go on until real market opening takes place, and also to be utilized after market opening to simulate further developments.
APENDIXES

List of references

ERGEG 2008; Regional Initiatives Annual Report

Europex/ETSO 2008: Development and Implementation of a coordinated Model for Regional and Inter Regional Congestion Management (draft version interim report)

EU Treaty 2008: Consolidated version article 101-106 of 09.05.2008


ETSO: Overview of transmission tariffs in Europe: Synthesis 2007

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Glossary

To be added in final version