Report

# Congestion management in liberalized electricity markets Theoretical concepts and international application

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# Congestion Management in Liberalized Electricity Markets - Theoretical Concepts and International Application

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# List of Acronyms

| Acronym | Full Name |
|---|---|
| APX | Amsterdam Power Exchange |
| ATC | Available Transmission Capacity |
| CAISO | California Independent System Operator |
| CCGT | Combined Cycle Gas Turbine |
| CfD | Contract for Differences |
| CM | Congestion Management |
| EEX | European Energy Exchange (Leipzig) |
| EuroPEX | Association of European Power Exchanges |
| ERCOT | Electric Reliability Council of Texas |
| ETSO | Association of European Transmission System Operators |
| FERC | The Federal Energy Regulatory Commission |
| FMC | Flow-based Market Coupling |
| FTR | Financial Transmission Rights |
| IEM | Internal European Market |
| IGO | Independent Grid Operator |
| ISO | Independent System Operator |
| LMP | Locational Marginal Pricing |
| MO | Market Operator |
| NECA | National Electricity Code Administrator (Australia) |
| NEMMCO | The National Electricity Market Management Company Limited (Australia) |
| NEPOOL | New England Power Pool |
| NETA | New Electricity Trading Arrangements (England) |
| NGC | National Grid Company (England) |
| NYPOOL | New York Power Pool |
| PJM | Pennsylvania-New Jersey-Maryland |
| PX | Power Exchange |
| SMD | Standard Market Design |
| SO | System Operator |
| TransCo | Transmission Company |
| TSO | Transmission System Operator |
| UMP | Uniform Marginal Pricing |
| ZMP | Zonal Marginal Pricing |

# Chapter 1

# Introduction

In the early 1990's the power supply industries worldwide started to undergo a period of extensive changes. Electricity markets moved away from vertically integrated monopolies towards liberalized structures with power delivery being a bundle of several services mainly including generation, transmission and distribution. One reason for restructuring lied in the expectation that competition could lead to a reduction of electricity prices and could stimulate the emergence of new technologies. The liberalization process was driven by several reasons, where the introduction of the Combined Cycle Gas Turbine (CCGT) provided a technological justification for competition in energy markets. The CCGT technology allowed for smaller plant sizes, nevertheless being at least as economical and efficient as thermal plants with their large economies of scale.[1] Thus, it was believed that new players may easily enter the market forming a competitive market structure.

However, transmission networks are still regarded as natural monopolies. Fixed costs are high while variable costs are comparably low. The monopoly transmits energy at significantly lower total cost than a competitive market. "Electricity grids exhibit large economies of scale and must be physically interconnected for maximum trading efficiency, making the grid a natural monopoly within a defined region."[2] Under such conditions, conventional wisdom suggests that government regulation must substitute for competition to discipline the behavior of firms. Deregulation of the transmission grid would not be suitable.

Although, the pricing mechanism of competitive markets does not provide efficient results for natural monopolies, and thus, transmission access and tariffs are subject to regulation, there is a growing need for market-based pricing concepts in transmission networks.[3] Ideally, these pricing concepts give not only correct economic incentives, but will also facilitate the physical operation of the network. In this regard especially congestion management and pricing methodologies received attention, as these methodologies are crucial for the efficient operation of electricity markets. This report intends to give an overview of congestion management and pricing concepts. As different market designs allow for different congestion management approaches the comparison and description is done in conjunction with overall market structures.

The report is structured as follows. Chapter 2 defines the concepts and terms as used in this report. Chapter 3 provides an overview on generic market structures and describes market-based congestion management and pricing approaches, such as capacity allocation and capacity alleviation methods. The overview is complemented by chapter 4 focussing on the implementation of the respective methods in electricity markets worldwide. Chapter 5 concludes the report by comparing the different concepts.

# Chapter 2

# Definition of Concepts

*Since the early 1990's electricity markets worldwide started to undergo a period of extensive changes and are still subject of redesign and restructuring. With the process of re-organization various design concepts evolved. Although, concepts may have similar features or may to some extend be identical they may be referred to different notions. As there is no unified "vocabulary" of electricity markets, this chapter aims at defining the terms and concepts as used throughout this report. If possible, definitions are made according to the common use of the respective term.*

## 2.1 Bilateral and Centralized Electricity Trading

With the ongoing liberalization of electricity markets various design concepts evolved. Although, market rules in different national markets may exhibit different features, at least two main approaches for market organization can be distinguished: a) direct or bilateral trading of electrical energy and b) centralized electricity trading.

According to the bilateral trade of electricity, market participants independently arrange power transactions with each other according to their own financial terms. Economic efficiency is promoted by consumers choosing the least expensive generators.[4] The bilateral approach gives a great latitude for decentralized decision making. It is motivated by the concept of free market competition providing the customers with "direct access" to the producer of choice. Therefore, the model is also referred to 'direct access method'.[5]

Whereas bilateral trade relies on the direct interaction of market participants, this is not the case for centralized trading models, where a common marketplace for energy trade is established. Market participants use this marketplace, which is mostly organized as closed-order-book auctioning system. In conjunction with centralized trading approaches the terms spot market, pool market and power exchange are frequently used. The following section defines the three concepts as used throughout this report.

## 2.2 Spot Markets, Pool Markets and Power Exchanges

### 2.2.1 Spot Markets

The term spot market origins from investment science, where a spot market is defined as a market where commodities are sold and bought for immediate delivery. This differs from a futures market, where the delivery will be made at a future date.[6] Thus, a crucial criterion to distinguish spot markets from other market types is the time horizon. The term spot market in conjunction with liberalized electricity markets is generally used in the context of day-ahead, hour-ahead and real-time markets, although the use of the terminology might differ slightly. Several authors refer day-ahead markets already to as futures markets[7, 8] Hence, they only consider real-time markets as spot markets, whereas e.g. the European Power Exchange, Nord Pool and Amsterdam Power Exchange refer day-ahead trade to as spot trade (see for instance [9, 10, 11]). In this section the common procedure of spot trade is described, where the focus is on the operation of day-ahead markets. Specific features concerning the operation of hour-ahead and real-time market are neglected in this section.

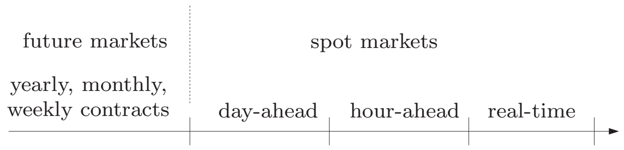


Figure 2.1: Comparison Future and Spot Markets

Spot markets for electricity are usually organized as closed-order-book auctioning systems, where the market players submit demand bids (load serving entities) and supply offers (generation companies). The marketplace operator receives these price and quantity bids (offers) and subsequently clears the market, where the equilibrium point of supply and demand determines the market clearing price[1] (figure 2.2).

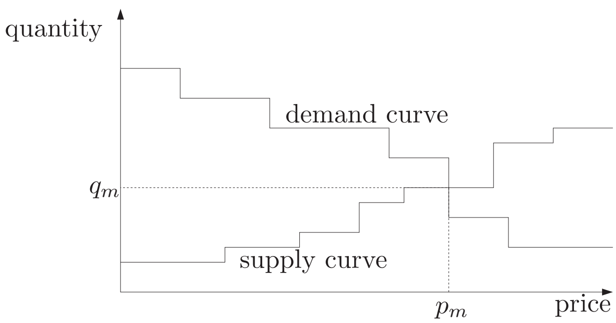


Figure 2.2: Pricing in a Spot Market
[16]

For the operation of spot markets four single stages can be figured out:[17]

[1]A system where one clearing price applies to all participants is called a uniform auction, as there exists only one uniform system price. In the context of strategic behavior and market power mitigation alternative clearing rules have been discussed, e.g. second-bid auctions, where the second-highest bid determines the clearing price. In contrast to uniform auctions, in pay-as-bid auctions participants pay (are paid) the prices of their actual bids (offers). Such a system is referred to as discriminatory auction, as prices are discriminated among the players. See references [12, 13, 14, 15]

**Bidding** The time period for which the bidding is made, is usually scheduled in hour or half-hour sections. For every interval bids (offers) can be transferred to the operator until a fixed deadline. Generators place their production offers in terms of price and quantity. Consumers submit their bids relating to the demanded load (resp. energy) and the maximum price they are willing to pay.

**Clearing** When the orderbook is closed the market operator calculates the market clearing price ($p_m$) and the market clearing quantity ($q_m$) for every scheduled interval. The market solution or equilibrium is set by the intersection of the supply and demand curves, where the last unit produced sets the market clearing price also referred to the system marginal price ($SMP$), which is applied to every dispatched unit (figure 2.2).

**Physical Delivery** After all trade has been settled, physical delivery takes place. Generators and loads produce (consume) energy according to the outcome of the market clearing process.

**Financial Transactions** The last stage of the centralized trading approach refers to financial transactions. The buyers pay the market operator the consumed energy, whereas the market operator pays the generators the injected energy. To all dispatched participants the system marginal price is applied.

The above stages characterize spot markets in general. For the time being issues related to the operation of hour-ahead and real-time markets have been neglected. Section 2.2.2 introduces the pool market concept and describes its relationship to spot markets. In 2.2.3 section the operation principles of a power exchange are outlined. These two concepts can be seen as effective implementations of spot markets, where the term spot market is generic to both.

### 2.2.2 Pool Markets

The term power pool historically evolved from the first U.S. power pool in the Pennsylvania-New Jersey area, which was founded in 1927 by three members. 1956 five signatories agreed to coordinate operations and planning as the PJM (Pennsylvania-New Jersey-Maryland) Interconnection.[18] The main functions of a power pool are unit commitment, dispatch and transaction scheduling. The power pool concept offers an organizational alternative to a merger that would establish a single vertically integrated company.[19] The term power pool gained further attention through the liberalization process of the UK electricity market, where in 1990 a pool structure was introduced. All suppliers had to sell their generation resources through the national wholesale pool,[20] subsequently, the National Grid Company (NGC) cleared the market by dispatching generation.[2]

While the bidding process in pool markets may follow the general procedure, which has been characterized in section 2.2.1, the distinct feature of power pools is the unit commitment and dispatch function. In pool markets the market operator, in charge of clearing the spot market(s), is also responsible for network access and operation. Thus, the market is cleared with explicitly taking generation *and* network constraints into account. This concept is also referred to as tight pool.[19] It is different from the operation of power exchanges, where a simple merit-order clearing is done without considering network constraints.

Section 3.1 discusses the relationship of pool and bilateral markets, the role of independent system and market operators.

[2] see section 4.3.2 for a detailed treatment of the England and Wales pool market.

### 2.2.3 Power Exchanges

Above a power pool was described as an organization, which offers several services to its members ranging from unit commitment to expansion and reinforcement planning. Power exchanges differ from this concept as they rather facilitate short-term energy trade, but "do not include economic unit commitment and dispatch, nor do they provide for coordinated long-term planning."[19] Thus, the power exchange operator is not necessarily concerned with network access and operation. Power Exchanges are established in several European Countries, such as the European Energy Exchange (EEX) in Leipzig (Germany), Powernext in Paris (France), Amsterdam Power Exchange (APX) in the Netherlands etc. The market is cleared through a merit-order dispatch as described in the spot market section 2.2.1. Power Exchanges can be run as automated platforms as done in the Netherlands.

### 2.2.4 Conclusion

The above sections described pool markets and power exchanges as two approaches of organizing spot trade in electricity markets (among hour-ahead and real-time markets). It was outlined that in pool markets the market operator is also assigned the function of an independent system operator, thus the ISO explicitly takes network operation into account for energy trade. In contrast to pool markets power exchanges facilitate short-term energy trade without necessarily obeying network constraints. The power exchange operator and the ISO are distinct organizations. Nevertheless, mutual coordination of activities is essential.

## 2.3 Transmission Pricing, Congestion Management, TransCo and ISO

When discussing transmission pricing, it is necessary to define what is meant by or included in the transmission service. Generally, the transmission function will facilitate a competitive electricity market by impartially providing energy transportation services to all energy buyers and sellers, while fairly recovering the cost of providing those services. According to [21] the structure of network charges should encourage:

- the efficient short-run use of the network (dispatch order and congestion management)
- efficient investment in expanding the network
- efficient signals to guide investment decision
- fairness and political feasibility; and
- cost recovery

The term transmission pricing incorporates congestion management as one essential feature. Thus, transmission pricing may be seen as embracing term, covering the pricing of all network related costs, whereas congestion management and pricing is a subtask. This report focusses on congestion management (CM), issues related to investment planning, system expansion and full cost recovery are not discussed. The reader may be referred to references [22, 23, 24].

To ensure efficient network use in most liberalized electricity markets a special entity the so called system operator exists. "This monopoly can be either a non-profit or a for-profit-entity."[25] The for-profit-entity in the US is called TransCo (short for transmission company). It owns, operates and manages the transmission system as a natural monopolist. A TransCo could maximize its profit by withholding transmission capacities, thus it is heavily regulated.[3]

The other choice is to introduce a non-profit-entity which is usually called Independent System Operator (ISO) or Independent Grid Operator (IGO). In contrast to the TransCo the ISO does not own - but manage - the transmission network. It does not have a motive to withhold transmission capacities in order to maximize its profit. Thus it is only slightly regulated.

In the following, the term TransCo will be used for an institution which owns and operates the network, whereas ISO refers to an independent system operator.

## 2.4 Conclusion

The above sections described various terms related to electricity markets as used in this report. Bilateral and centralized electricity trading have been characterized as two approaches for organizing liberalized markets. The term spot market has been introduced and distinguished from future markets, where spot markets may be organized as power pools or power exchanges. A further distinction may be made according to the time horizon, such as day-ahead, hour-ahead and real-time markets. In most liberalized markets a system operator is in charge of network operation and pricing. Depending on the organizational form this may either be a TransCo (often found in Europe) or an ISO (predominantly in the US)[21].

Chapter 3 discusses congestion management methodologies in conjunction with specific market structures, as certain designs advantage respectively disadvantage specific CM schemes.

[3]In general there are two approaches for the regulating of natural monopolies, while the two approaches mark the extremes of the regulatory spectrum. On the one hand there is cost-of-service regulation (COS), on the other hand there is perfect price-cap regulation.

# Chapter 3

# Congestion Management and Generic Market Structures

*Transmission pricing and congestion management are distinct elements of electricity market design. In contrast to solutions configured to match the unique structural and historical features of specific national markets this chapter aims at providing a conceptual overview on congestion management methods. It is emphasized that transmission pricing and congestion management have to be evaluated in conjunction with overall market design, where different generic market organizations allow for different congestion management methodologies. The description follows the evolution from uniform to zonal to nodal pricing models.*

## 3.1 Generic Market Structures

In [26, 27] the interdependency of general market design and CM concepts is outlined. Thus, in the following characteristic market structures are described. The overview is organized according to concepts derived from a power pool (sections 3.1.1 and 3.1.2) and concepts rather relying on decentralized trading approaches (section 3.1.3).

### 3.1.1 Power Pool and Financial Bilateral Trading

Figure 3.1 depicts a market structure where physical energy trade is allowed only through a mandatory power pool.

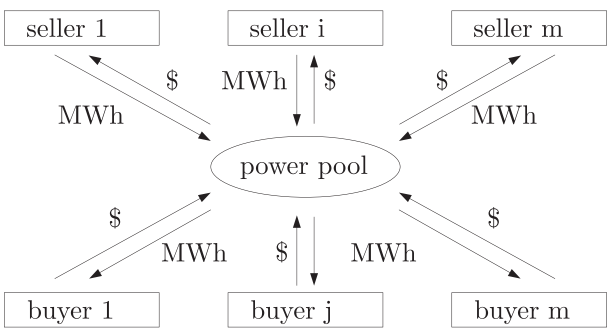


Figure 3.1: Mandatory Power Pool
[16]

No direct transactions between sellers and customers are possible. The system price is calculated based on the bids from generators and loads the pool operator receives, where Hogan claims the pool dispatch and the transmission wires to be distinct essential facilities.[28] The pool operator carries out all functions relating to the centralized marketplace (the pool) and beyond fulfills objectives as a system operator by obeying generation and network constraints, i.e. performing unit commitment and dispatch.

In a mandatory pool model no physical, bilateral transactions are allowed besides the pool. One common method of hedging price risks is the use of contracts for differences (CFDs). This instrument is of complete financial nature. "If two traders wish to make a bilateral transaction for some quantity $q$ at a price $p$ at some future time, they may enter into a CFD."[29] The buyer pays the seller $q(p - p_s)$ where $p_s$ is the system price and $p$ the contract price. The net payment involved amounts to $pq$. Figure 3.2 shows the financial transactions between the buyer, the seller and the pool operator.[1] Crucial to CFDs is the underlying spot market, where the purpose is to eliminate uncertainty in temporal spot price variations.[29]

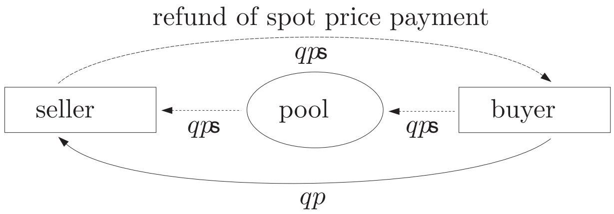


Figure 3.2: Contracts for Differences
[16]

Mandatory power pools are implemented in Singapore and Australia. In Ireland the concept is proposed to be introduced in the near future.

### 3.1.2 Power Pool and Physical Bilateral Trading

Figure 3.1 depicts a market structure where generators and loads may either settle into bilateral contracts or trade energy through the pool.

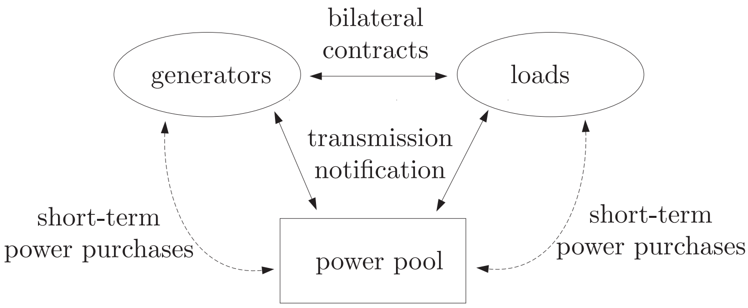


Figure 3.3: Power Pool with Physical Bilateral Contracts
[16]

In contrast to the above described market design physical bilateral contracts are explicitly allowed. If generators opt for self-scheduling according to their bilateral transactions, they have to notify the pool operator about the points of injection/withdrawal of energy. In case generators bid to the pool's spot markets the pool operator will carry out unit commitment and dispatch functions.

[1] The system was implemented under the old England and Wales pool design.

This structure is suggested by the US Federal Energy Regulatory Commission (FERC) as standard market design (SMD). It is implemented in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, in New York and New England and scheduled for introduction in California.

### 3.1.3 Decentralized Market Structures

The structures in sections 3.1.1 and 3.1.2 premised the existence of a pool operator whose main objectives are to make the pool market work and to ensure the reliability of the transmission network by scheduling network services. Although both functions are strongly connected and Hogan concludes in [28] that they are very likely to be carried out by one entity, a different approach is conceivable. The operation of a day-ahead spot market may be separated from network operation (see figure 3.4). Although, the ISO may still run hour-ahead and real-time spot markets to keep the system in balance and relieve congestion, day-ahead spot markets may be run by different entities. Scheduling coordinators (SC) "pool" a variety of generating resources to meet the combined loads of multiple customers.[30] Additionally, they are in charge of balancing generation and demand of market participants in a certain area and submitting the preferred schedules to the ISO. Employing coordinators for a number of loads and generators means improving efficiency of the regional network usage, whereas the ISO is responsible for optimizing the grid as a whole. Thus, both entities are associated with the coordinating of the transmission services.

Generally, electricity trade in a decentralized market structure allows the following transactions:

1. Generators ($G_i$) and loads ($L_i$) may settle into physical bilateral contracts (1) and subsequently notify scheduling coordinators (SC) about their physical portfolios.

2. Generators ($G_i$) and loads ($L_i$) may trade energy through the day-ahead market at the power exchange (2).

3. Generators ($G_i$) and loads ($L_i$) may participate in the balancing (real-time) market of the ISO (3).

In order to ensure efficient network use a mutual information exchange is necessary between scheduling coordinators, the power exchange and the ISO.

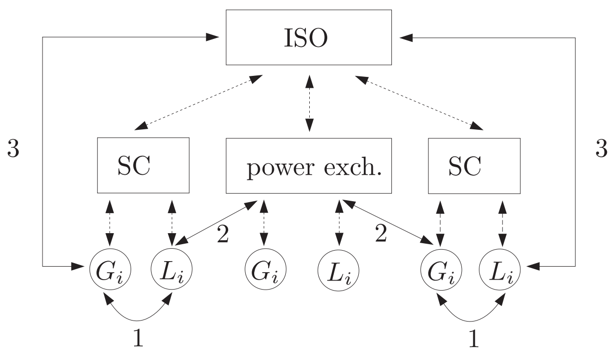


Figure 3.4: Decentralized Market Design

A similar decentralized market design is to be found in Germany and was proposed for California[2] before the energy crisis in 2000/20001. Additionally, the

[2]Eventually, all incumbent generators had to sell their energy through the power exchange. As a result the Californian model became known as power pool, although the structure was not a pool in the sense, that the system operator provided unit commitment and dispatch of generation.

Nordic system may be regarded as following a decentralized approach, as there is no central scheduling/dispatching entity. Scheduling is the responsibility of individual generating companies. There is only a common power exchange (Nord Pool).[26]

### 3.1.4 Conclusion

The above described models may be seen as specific implementations of four general design principles for electricity markets:[31]

1. Wholesale competitive generators bid to supply power to a single pool. Load-serving companies buy wholesale power from the pool at a regulated price and resell it to the retail loads
2. Wholesale competitive generators bid to supply power to a single pool, while load-serving companies then compete to buy wholesale power from the pool and resell it to the retail loads.
3. Combinations of (1) and (2) with bilateral wholesale contracts between generators and load-serving entities.
4. Combinations of all previous plus contracts between all entities and retail loads.

In the next sections CM concepts are described, where the interdependencies of market design and CM methodologies are pointed out. Section 3.2 provides an introduction to CM. Section 3.3 details the methodologies ranging from uniform, zonal and nodal pricing to the auctioning of transmission capacity.

## 3.2 Introduction to Congestion Management

In the latest report by the European Commission Directorate-General Energy and Trade it is concluded, that "one of the main targets of the liberalization of the electricity supply sector in the European Union is the creation of a truly Internal Electricity Market", where the limited cross-border transmission capacities have to be allocated in an efficient way to deter international electricity trade as little as possible. The efficient allocation of scare transmission capacity is one of the main tasks of congestion management, which comprises all actions and measures applied to handle network access in the presence of congestion. In addition to capacity allocation, CM methodologies may also allow for alleviating congestion in real-time. The concepts can be distinguished as follows:

| Capacity Allocation Methods | Capacity Alleviation Methods |
|---|---|
| Nodal Pricing | Generation Redispatching |
| Zonal Pricing (Market Splitting) | Buy-Back or Countertrade |
| Explicit Auctioning | |

Capacity allocation methods aim at allocating transmission capacity mostly before the physical delivery of the energy takes place. Capacity alleviations methods are also referred to as remedial actions. When using these methods, market parties are not directly notified of the existence of congestion. Free trade is allowed, where the ISO takes actions in order to relieve possible congestions. Capacity alleviation methods may also be used in real-time markets, if congestions have to be relieved immediately. Figure 3.5 displays the different phases of congestion management according to [3], where all applied concepts should generally meet the following requirements [32].

- *not discriminate*: Each market participant - be it a consumer or a producer - should be treated equally and the price for a specific good at a specific place and time should be the same for everybody

- *give economic signals*: The method should give incentives to producers, consumers and the network operator to improve the systems in order to relieve transmission constraints.

- *be transparent*: The implementation should be well defined and transparent for all participants.

- *be feasible*: The available resources (information, computer systems) need to be capable of producing the necessary quantitative results in the time frame available.

- *be able to interact with other systems*: In a real system the surrounding TSOs and their specific methodologies have to be taken into account. The implemented system needs to interact with other systems.

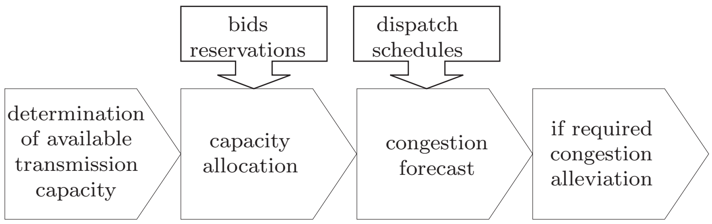


Figure 3.5: Phases of Network Access with Respect to Congestion [3]

The requirements above comply with the criteria outlined in [3]. Special emphasis is put on the claim for market-based congestion management. Thus, two currently used CM methods are excluded from assessment as done in [3]. First come first served and pro-rata methods fail to meet the above listed criteria.[3] For further evaluation the following capacity allocation methodologies remain: nodal pricing, zonal pricing (market splitting), uniform pricing, explicit and coordinated auctioning for interarea CM. The main characteristics of these approaches are outlined in section 3.3. Section 3.4 focusses on capacity alleviation methods, such as buy-back, redispatch and curtailment procedures. The methodologies are evaluated taking into account the above described generic market structures, with regard to implementation issues and feasibility in conjunction with specific market rules.

## 3.3 Capacity Allocation Methods

### 3.3.1 Nodal Pricing

The general idea of nodal pricing is to 1) model an electricity market with its various economical and technical specifications, such as generators' cost functions, demand elasticity, generation limits (individual and overall), power flow limits etc. and 2) optimize the system which is synonymous to maximizing social welfare. One crucial outcome of the optimization procedure is the price at each node, the so called nodal or spot prices. It reflects the temporal and local variations of the energy price relating to the energy demand. The methodology comprehends, that electricity has not only to be generated, but also has to be delivered to a particular node, taking into account transmission constraints and electrical losses.

[3] Neither first come first serve nor pro-rata methods take into account the willingness to pay. Thus, it can not be ensured that market participants with a high valuation for transmission capacity will indeed be scheduled.

Nodal pricing can be seen as fully coordinated implicit auction.[21] Generators and loads do not explicitly participate into auctions for transmission capacity. Capacity is implicitly allocated through bids for production/consumption at a specific location (bus). Nodal pricing is often used in conjunction with a pool-based market design. The ISO collects all bids and is then in charge of clearing the market by maximizing social welfare while satisfying network constraints. To realize this objective, the ISO solves the following optimization problem:

$$maximise = \sum_k B(d_k) - \sum_j C(g_j) \tag{3.1}$$

subject to:

$$\sum_k d_k + losses - \sum_j (g_j) = 0 \qquad \text{(a)}$$

$$|z_i| \leq z_i^{max} \qquad \text{(b)}$$

$$g_j \leq g_j^{max} \qquad \text{(c)}$$

with:

| | |
|---|---|
| $d_k$ | demand at node $k$ |
| $g_j$ | generation at node $j$ |
| $B(d_k)$ | consumers' benefit |
| $C(g_k)$ | producers' generation cost |
| $g_j^{max}$ | maximum generation capacity at node $j$ |
| $z_i$ | flow along line $i$ |
| $z_i^{max}$ | maximum permissible flow along line $i$ |

As seen in the first part of equation 3.1 the social welfare is equal to the benefit from consuming electricity less the cost of generation. This gives the objective function which is subject to four sets of constraints. Constraint a) describes the energy balance. The total generation must not be less than the sum of the demand and the losses. Equation 3.1b gives the line flow constraints and equation 3.1c the generation constraints. For the optimization problem the Lagrangean with the Langrangean multipliers $\mu_e$, $\mu_i^{QS}$ and $\mu_j^{max}$ can be formulated as follows:[4]

$$\begin{aligned} \text{maximize} \quad & \sum_k B(d_k) - \sum_j C(g_j) \\ & -\mu_e \left( \sum_k d_k + losses - \sum_j (g_j) \right) \\ & -\mu_i^{QS} \left( |z_i| - z_i^{max} \right) \\ & -\mu_j^{max} \left( g_j - g_j^{max} \right) \end{aligned}$$

From the Langrangean the following expression for the nodal price can be derived:[5]

$$p_k = \mu_e \left[ 1 + \frac{\delta losses}{\delta d_k} \right] + \sum_i \mu_i^{QS} \frac{\delta z_i}{\delta d_k} \tag{3.2}$$

The scarcity of transmission capacity is reflected by the multiplier $\mu_i^{QS}$. General optimization theory states, that the Lagrangean multipliers define, how the

[4]For a detailed description on optimization methods see [33]:

[5]A stepwise description of the nodal price derivation can be found in [34]. In this paper only the implications for transmission pricing are relevant.

optimal solution reacts, if the relevant constraint is changed marginally. When there is a non-binding constraint (e.g the capacity limit is not reached), the value of the multiplier is zero. A change of the constraint (e.g. a marginal decrease or increase of a certain, available capacity) will have no influence on the solution. In case of a binding constraint the multiplier determines the change of the equilibrium solution, if the constraint was marginally tightened (e.g. a decrease of available capacity) or eased (e.g. an increase of available capacity). When having a monetary objective function (as in the case of electricity markets) the sensitivities will also be monetary. Thus, the multiplier sets a threshold on the price per unit, which one would be willing to pay in order to increase an available capacity marginally (to ease the constraint). This price threshold is referred to as shadow price. In the above context $\mu_i^{QS}$ reflects the market participants' valuation of a marginal increase or decrease in available transmission capacity. The monetary valuation will be "zero" when the transmission limits are not reached and it will rise the scarcer the transmission resources get. The overall nodal price $p_k$ will subsequently rise (as it is a sum of the price for generation and transmission), setting an incentive to invest in generation facilities at or close to the affected bus.

### Implications for Congestion Management and Pricing

With no transmission constraints and losses neglected there will be one "system lambda" resp. one system price for the whole network (market).[35] As the market in this case does not consider the transmission resources scarce, no congestion charge can be collected. The situation changes when at least one line is congested, resulting in different nodal prices as at least one $\mu_i^{QS}$ will be non-zero. The difference in nodal prices then gives the congestion charge (rent)(equation (3.3)).

$$NR = \sum_{i \neq j} (\rho_i - \rho_j) \mid P_{ij} \mid \tag{3.3}$$

with:

| | |
|---|---|
| $\rho_i$ | price at node $i$ |
| $\rho_j$ | price at node $j$ |
| $P_{ij}$ | power flow from node $i$ to $j$ |

The theory is illustrated, using a simple three-bus network with two generation buses and one load bus.

### Three-Bus-Example

For a simple discussion of the nodal pricing mechanism the network in figure 3.6 is considered.[6]
At bus 1 and 2 the ratios of \$25/MWh and \$45/MWh reflect the marginal cost of the generators. When there are no generation or line constraints, it is obvious, that the cheapest generator (located at bus 1) will produce all the electrical energy demanded by the load at bus 3. The price of energy at all nodes will adjust to \$25/MWh and no network revenues will be collected (see equation (3.3)). Subsequently, there will be no producers benefit (defined as the difference between revenue and cost). Generator 1 sells its energy at marginal cost of 25 \$/MW and Generator 2 is not dispatched.

The situation is now be modified by setting the demand at bus 3 to 1000 MW and the generation limit for generator 1 to 750 MW and for generator 2 to 500 MW. The least cost will be reached, when generator 1 produces up to its limit

[6] Losses will be neglected in the example.

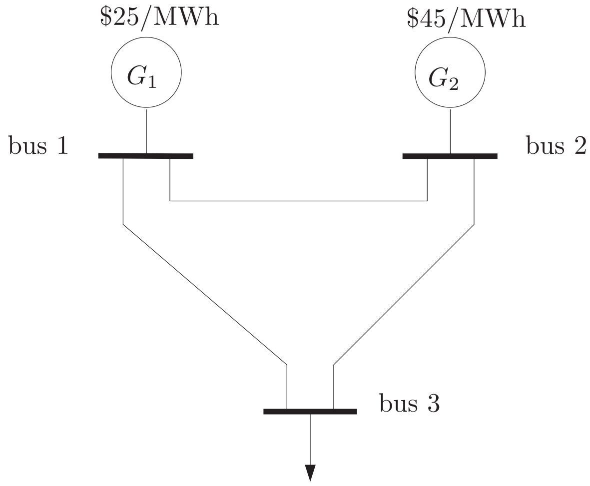


Figure 3.6: Example Nodal Pricing

of 750 MW and generator 2 supplies the remaining output. This will result in an overall energy price of $45 per MWh, as the next MWh will be produced by Generator 2 with marginal cost of 45$/MWh. No network revenues will be collected. In contrast to the situation with no generation limits, Generator 1 will now collect a benefit of 15000$ as the price at bus 1 is 45$/MWh and the marginal cost is $25/MWh. Generator 2 does not receive a benefit as it sell the energy at marginal cost.

Considering a last situation, the line from bus 1 to bus 2 shall be congested, where all lines have the same impedances. The nodal price at bus 3 will then adjust to $35/MWh where the prices at buses 1 and 2 are given by the marginal generation cost at the respective buses.Thus, no producers benefit can be gained. If there were a load at bus 1 or 2 it would be only possible to feed it from local generation. Additional generation at other buses would cause the line from bus 1 to 2 to exceed its thermal limits because of the existing congestion. Increasing the demand at bus 3 by 1 MW, generator 1 and 2 have to supply 0.5 MW each in order to cause no additional flow on the line from bus 1 to bus 2. This results in the energy price of $35/MWh at bus 3 ($0.5 \cdot \$25/MWh + 0.5 \cdot \$45/MWh$). In this case network revenues of 5000$ can be collected, as the ISO buys energy for 30000$ ($\$25/MWh \cdot 750MWh + 45\$/MWh \cdot 250MWh$) and sells it for 35000$.

There are at least two different approaches for utilizing the congestion revenue (rent). Either the ISO invests the rent into network reinforcement or the rent is shared among the market participants, where a common way of allocation is the use of financial transmission rights (FTRs).

### Allocation of Congestion Rent through FTRs

The use of financial transmission rights (FTRs) was proposed by William Hogan of Harvard University. FTRs may be seen as an evolution of contracts for differences. Section 3.1.1 showed that CfDs are used to hedge price risks in pool markets. The system is applicable if there is only one pool clearing price for the whole network.[7] In case of nodal pricing, it is very likely that prices differ from node to node, thus, a possible hedging mechanism has to account for these locational differences. FTRs are designed to mitigate the exposure to price risks originating from congestion at different network locations.[36] As all transactions pay congestion charges based on the difference between nodal prices, market

[7]See section 3.3.3 for uniform marginal pricing (UMP).

players may hedge against this payment by buying FTRs along the path from source to sink. "An FTR's economic value is based on the MW reservation level multiplied by the difference between the LMPs of the source and sink points." FTRs are directional, and thus, may be either a benefit (in direction with the congested flow) or a liability (opposite direction as congested flow). The use of FTRs makes a Simultaneous Feasibility Test (SFT) necessary, which ensures that all subscribed FTRs are within the capability of the transmission system.

A congestion management and pricing system based on nodal pricing and the use of FTRs are essential features of FERCs standard market design. The system is in use within the PJM Interconnection, New England and New York.

### Cost Recovery Problem

As stated in section 3.3.1 no congestion in the network result in zero network revenues, which may be not acceptable for a network owning or operating company. To overcome this problem a complementary charge can be defined (equation (3.4)):

$$CC_l = \max\{annual\ cost_l - NR_l\ , 0\} \tag{3.4}$$

with:

| | |
|---|---|
| $NR_l$ | marginal annual revenue line $l$ |
| $CC_l$ | complementary charge line $l$ |
| $annualcost_l$ | annual cost line $l$ |

Without the definition of a complementary charge, spot pricing theory fails to recover the total incurred network cost, in case the installed system capacity is not optimal[35], although "the farther away the network is from the single node ideal situation, the larger is the network revenue"[35]. For the allocation of the complementary charge three methods have been proposed:[37]

**Adjustment of marginal prices** Spot prices are modified according to some criterion(an additive term, a multiplicative term, Ramsey prices, etc. in order to match the marginal network revenues and the total network cost

**Extent of use allocation** The complementary charge is allocated among the agents depending on their "extent of use" of the network.

**Benefit allocation** The complementary charge is assigned among the agents depending on the economic "benefit" that each one of them obtains from each network facility.

Theory and implementation of the above methods are extensively described in [37].

### Nodal Pricing and Generic Market Structures

The above section introduced nodal pricing according to the initial definition by Schweppe et.al. [38]. Nodal prices are the 'outcome' of an optimization process, where the objective is to maximize social welfare according to generation and network constraints. For the implementation of the concept this data has to be known to the central entity concerned with the optimization. The information needs can by easily satisfied in an vertically integrated industry structure, where in a liberalized environment auctions are common way of providing the relevant data. Generators and loads bid their willingness to produce (consume) in an auction supervised by the ISO. The procedure follows the previously outlined spot market rules. The ISO then performs a security constrained unit commitment (SCUC) and dispatch. Thus, nodal (spot) pricing as well as other marginal pricing methods are above all suitable for integrated market structures, such as pool markets. Only in pool market the specific information needs for the optimization process can be satisfied. If there are generation as well as network owning companies, the spot price has to be decomposed in order to allocate the different components to the relevant entities,[39] which may be a complex and strenuous task. Furthermore, in [31] it is stated, that "a mix of bilateral and spot markets creates difficulties in applying methods based solely on nodal transmission pricing [...]."

#### Conclusion

"At a given node $k$ of the transmission network and at an instant of time $t$, the spot price of electricity $\rho_k(t)$ is the derivative of the system operation cost with respect to the demand at node $k$ and time $t$, i.e the short term marginal cost of electricity with spatial discrimination."[35] Marginally network revenues implicitly result from this spatial discrimination of spot prices[40], where in [35] it is shown, that the network costs can only be recovered when the installed capacity is optimal. For full cost recovery the introduction of a complementary charge is proposed.[37] To satisfy the information needs of nodal pricing centralized market designs are required, such as pool-based concepts. Nodal pricing is proposed as FERC standard market design in the US, it is implemented in the PJM-Interconnection, in New York, New England, New Zealand and it is proposed for California and Ireland (see section 4.1).

### 3.3.2 Zonal Pricing

#### Introduction

Zonal pricing[8] - in accordance with nodal pricing - establishes different electricity prices for different locations in the network. In contrast to nodal pricing where prices in the case of congestion might differ for every node, for zonal pricing a group of nodes is aggregated to one zone.[9] These zones are mostly defined *a priori* as the concept focusses on certain flowgates, which might be subject to congestion. An example is the Norwegian system, where the system operator splits the national transmission system into two zones (North and South) in the case of congestion. If the demand for transmission services does not exceed system capabilities, different network zones are not established, and thus, there is only one clearing price for the whole network. In the following the market splitting procedure is described.

#### Market Splitting Procedure

Although, for market splitting a central dispatch or unit commitment is not necessary[26], it "requires organised electricity exchanges on both sides of each congested connection, or an exchange which can serve both sides."[41] Generators and loads in each zone bid into the power exchange(s), the system operator(s) and the market operator(s) are then in charge of coordinating actions for the market splitting procedure, which is explained using the topology in figure 3.7.[10]

Within the network two zones have been identified, as the transmission line (the flowgate) connecting the zones may be subject to congestion. The transmission line has a maximum capacity of $P_{ab}^{max}$. In zone A generation facilities with low marginal cost are located (e.g. hydro plants), whereas in zone B there are major load centers with little excess supply. Generators and load bids in each zone are given by $P_G^A$, $P_D^A$, $P_G^B$ and $P_D^B$. For the first step of the market splitting procedure, the market is cleared as if there was no transmission constraint. Thus, there will be one price $p_u$ for the whole market. If the lineflow in this unconstrained case $P_{ab}^u$ exceeds the maximum lineflow $P_{ab}^{max}$, the market will

[8] Zonal pricing in the Scandinavian context is also referred to as area pricing

[9] A group of nodes might be also be referred to as super-node.[32]

[10] The example is taken from [26].

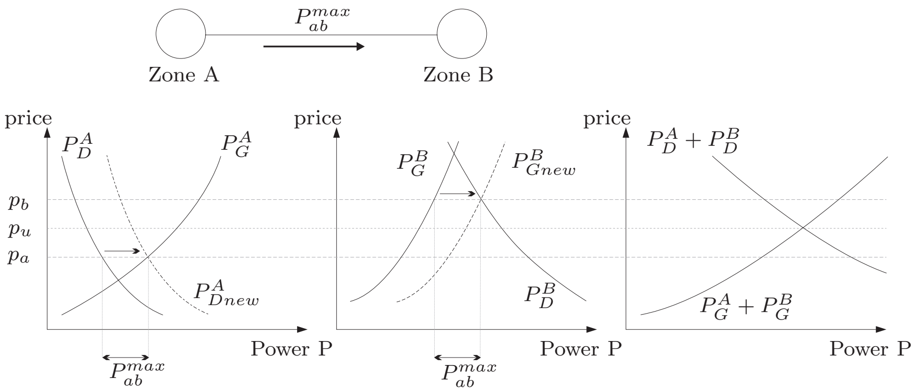


Figure 3.7: Example Market Splitting

be split. The market operator now maximizes arbitrage trade, i.e. utilizes the transmission capacity up to the limit of $P_{ab}^{max}$. Thus, it buys energy within the low-price zone A and sells energy to the high-price zone B. These activities may be regarded as a shift of demand resp. supply curves in zone A and B. The new demand curve in zone A is given by the following horizontal addition (a shift to the right along the x-axis in figure 3.7):

$$P_{Dnew}^A = P_D^A + P_{ab}^{max} \tag{3.5}$$

Hence, the supply curve in zone B is defined through (a shift to the right along the x-axis in figure 3.7):

$$P_{Gnew}^B = P_G^B + P_{ab}^{max} \tag{3.6}$$

The transmission capacity between the two zones is now fully utilized. Due to the arbitrage trade between the zones, the price in zone A increases to $p_a$ and the price in zone B decreases to $p_b$, which corresponds to an increase in overall social welfare.[11] As the market operator (or the system operator) buys in the low-price area and sells in the high-price area, it collects a congestion rent. As in the nodal pricing system, the rent may be used to invest into the grid or may be allocated among the participants. A common way of hedging congestion risk in zonal markets is the use of flow gate transmission rights (FGRs), which are similar to FTRs and entitle the holder to financial compensation.

### Zonal Pricing and Generic Market Structures

The Scandinavian countries give a working example of zonal pricing, emphasizing that no central dispatch and unit commitment is necessary as with nodal pricing. The Nord Pool system comprises of Norway, Sweden, Finland and Denmark. There is one central power exchange and three transmission system operators (the national grid companies). In [26] it is stated that “The fact that scheduling and dispatch is left to the market participants on the basis of individual profit maximization, brings the Nord Pool solution closer to a real free market than other deregulated system.” Nevertheless, in [41] it is stated that market splitting “either requires organised electricity exchanges on both sides of each congested connection, or an exchange which can serve both sides.” Furthermore, there is a need for coordination between transmission system operators and power exchange operators, the latter will be at least in charge of collecting the bids, where the TransCos have to notify the power exchange about available transmission capacity. The shift from nodal pricing as centralized CM approach towards the more decentralized zonal pricing obviously incorporate a higher degree of coordination and transaction among market entities.

[11] A detailed mathematical formulation of market splitting can be found in [42].

**Conclusion**

The above sections introduced zonal or area pricing as CM concept that splits the network in different prices zones in the case of congestion. In the central European context market splitting provided a basis for the evolution of the market coupling approach. The concept is put forward by the forum of the European Transmission System Operators (ETSO).[12] Zonal pricing as nodal pricing is an implicit auctioning concept, as no explicit bids for transmission capacity are made. Capacity is allocated implicitly by the bids of the generators/loads in their respective zones and by the system operator maximizing arbitrage trade.

### 3.3.3 Uniform Pricing

**Introduction**

The sections above have shown that for zonal pricing certain areas in a network are aggregated to predefined price-zones. In these zones, prices are not distinguished node by node, but are unified. Concluding this evolution one may regard the whole network as one price-zone. This concept is referred to as uniform marginal pricing (UMP). It was implemented in the pool-based England and Wales market, in the 1997 PJM market and the phase-1 ISO New England market.[43] The characteristics of UMP are described in the following section. The description follows the structure outlined in [43], where it becomes obvious that uniform marginal pricing is only efficient in the absence of congestion. Otherwise an uplift payment[13] is necessary, which is not regarded to provide economic efficiency. This uplift payment will not be used as market-based signal to relieve congestion, but it is intended to cover the cost of congestion relief. Congestion relief in this model may be achieved by curtailment and redispatch methods.

**Uncongested Network**

For the description of uniform marginal pricing (UMP) figure 3.8 is used. First, we will not impose any transfer limit. According to [42] in a UMP-model two stages can be distinguished: market dispatch (MD) and congestion redispatch (CR). In the MD phase only one zone exists, and thus, no constraint interfaces are considered, whereas in the CR phase generation is redispatched following the adjustment rules of the ISO. This CM approach may also be characterized as capacity alleviation method, as in the MD stage market participants are not notified of congestion, but in a subsequent step the ISO takes remedial actions (such as redispatching) for congestion relief.[14]

For the example given in figure 3.8 in the MD phase, the ISO will purchase all energy from generator 1 at a price of \$10/MW. This conforms with a least cost dispatch. As there is no active line limits, and thus no congestion, a CR phase is not necessary. All participants pay (are paid) the same system marginal price. The system faces no physical difficulties and the dispatch is regarded to be efficient.

**Congested Network**

For the description of UMP in a congested network again figure 3.8 is used, where the transfer limit of the transmission line is set to 100 MW. The outcome of the MD phase for the congested system matches the outcome in the uncongested case. The market clearing will deliver a solution, where all energy is purchased

[12] Whereas market splitting separates different areas, the direction of market coupling is opposite. Different regions (countries), which originally existed as isolated (national) markets will now be linked.

[13] In the England & Wales pool market, the uplift payment also included other components.

[14] In this section only a short example is provided to exemplify UMP. For a detailed description of capacity alleviation methods see section 3.4.

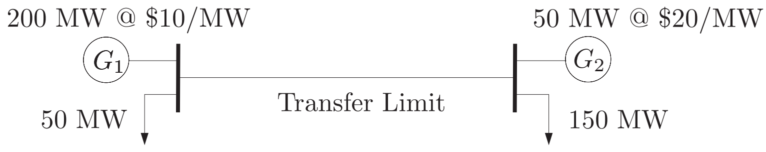


Figure 3.8: Example Uniform Pricing

from generator 1 at a price of $10/MW. This dispatch leads to congestion and makes the CR phase necessary. The ISO may relieve congestion by 'constraining off' generator 1 by 50 MW and 'constraining on' Generator 2 by 50 MW. Due to the difference between the unconstrained and the constrained schedule the ISO faces additional cost of 500$ ($50MW \cdot (\$20/MW - \$10/MW)$). This additional cost (payments) are also referred to as operational outturn [44]. Generally, "stations in an 'export constraint' region will have to produce less, while those in an 'import constrained' region will have to produce more."[44] A unified mathematical framework for both the MD and the CR phase is presented in [42]. The optimization problem is not outlined here as UMP has several shortcomings, which make it less suitable for practical implementation.[15] The drawbacks are presented in the subsequent sections.

#### Uniform Pricing and Generic Market Structures

While the MD phase in the UMP model does not differ from the general operation principles of spot markets, according to [43] the CR phase makes "the frequent exercise of command and control" necessary, where these actions "are regarded to "deprive the choices promised to participate and goes against fundamental principles of competitive markets."[43] A common way of introducing market principles is the use of incremental/decremental bids to resolve congestion. In that case market participants will submit their valuation of being redispatched. An incremental bid represents the participants' valuation to be scheduled up (more power output), a decremental bid represents the valuation to be scheduled down (less output). These principles may also applied to the demand side. According to the submitted bids the ISO will solve the corresponding optimization problem. Nevertheless, the inc/dec bids system is suspected to allow for gaming, as "participants may first over-schedule to create congestion, and then submit incremental and decremental bids for additional benefits [...]"[43]

#### Conclusion

For a network without congestion the UMP model delivers the same results as nodal and zonal pricing. The solution is supposed to be efficient and does not cause physical problems. Nevertheless, in a network where congestion is likely to occur, UMP fails to deliver an efficient solution. The common practice of command and control in UMP models is not compatible with the principles of competitive markets. A modification towards the use of incremental/decremental bids appears problematic.[43]

### 3.3.4 Interarea Capacity Allocation

#### Introduction

In the above sections different CM concepts were presented, which aimed mainly at capacity allocation in a certain region or network. This network may be

[15] For the optimization problem of the CR phase different objective functions are possible, ranging from minimum shifts in power generation to a cost minimization of dispatch activities.

regarded as one control area, with one ISO being responsible for efficient network use, i.e. congestion management and pricing, balancing of the system as well as ancillary services. In the context of the liberalization of European electricity markets the role of the transmission system and particular the role of cross-border interconnections has changed. As networks and markets 'grow' together there is a need for congestion management between certain areas or countries. Especially, the allocation of scarce cross-border transmission capacity has been under discussion recently.[3] In contrast to the above present CM concepts these methods may involve more than one ISO. The following sections summarize the main concepts.

### Explicit Auctioning

For capacity allocation at several European borders explicit auctioning is used. This applies to the tie lines between e.g. Germany and the Netherlands, Germany and Denmark, France and the United Kingdom, the United Kingdom and Ireland.[16] In [45] explicit auctioning is characterized as follows: "The seller (TSO) determines ex ante the available transmission capacity (ATC) considering security analysis, accepts bids from potential buyers and allocates the capacity to the ones that value it most." Thus, explicit auctioning is a market-based concept, which provides economic signals. The main features of the auction can be explained using the example for zonal pricing, with zone A being a low-price area and zone B being a high-price area. Loads from zone B might be interested in settling contracts with generators in zone A to benefit from the price difference between the two regions. Hence, the valuation of, e.g. loads in zone B, corresponds exactly to the energy price difference between the zones. If the loads in zone B (resp. any market participant) bid higher than the energy price difference, the benefit they gain from cross-border trading will not make up for the payment for transmission capacity. Thus, "with perfect foresight, bidders for transmission capacity would predict the electricity market outcome with efficient use of the transmission"[3] - or in other words - "the price reflects the cost of using capacity to the social welfare."[45]

Auctions for capacity may be designed as uniform or discriminatory auctions, where "the price of the interconnector is set equal to the lowest accepted bid."[41] In contrast to implicit auctions, where capacity is implicity allocated by the energy bid at a specific location, explicit auctioning separates the energy from the transmission market. According to [41] this might be considered as advantage as well as disadvantage. The separation reflects the unbundling of energy and transmission networks, but it makes two separate transaction necessary. This increased complexity may hinder trade or complicate trading activities of market participants. Another drawback, outlined in [46] is, that current auctions fail to account for parallel flows in meshed networks. In this context a new method has been proposed called Coordinated Auctioning.

### Coordinated Auctioning

In compliance with explicit auctioning, coordinated auctioning splits electricity trading into two markets, one for transmission capacity and one for energy. Participants have to ensure to 'own' sufficient transmission rights to conclude their energy exchanges. However, coordinated auctioning tries to overcome the problems associated with explicit auctioning, by accounting for the effects of loop flows in the network. A central auctioneer is introduced, which manages capacity allocation at all borders included in the Internal European Market (IEM). The coordinated auction concept was suggested by the Association of European Transmission System Operators (ETSO) in April 2001. For coordinated auctioning three steps can be identified[21]:

[16] All currently used cross-border capacity allocation and CM methods can be found in [45].

1. Each (national) system operator informs the central auctioneer about the available transmission capacity
2. Market participants submit bids to the central auctioneer
3. The auctioneer allocates transmission capacity using a model similar to nodal pricing

Similar to flow-based market coupling, coordinated auctioning tries to link different zones rather than merging them. Market participants may value their willingness to pay for transmission rights by comparing the different zonal prices. Hence, 'rational' bidders for transmission rights will submit bids equal to the zonal difference in energy prices, as the savings for 'cheaper' energy are traded off against the transmission cost. With perfect foresight and all information available a coordinated auction, will lead to the same allocation as the nodal pricing approach. However, in [47] it is pointed out, that this "perfect anticipation assumption" under certain conditions may not seem appropriate. If marginal cost and willingness to pay are not constant, traders can only value their bids with *solving* a full nodal pricing problem and "this is certainly not what ETSO wanted to assume when it submitted its proposal"[47]. For a detailed description of the underlying argumentation the reader is referred to [47], where also the impact of an aggregated network is discussed. For coordinated auctioning several issues remain to be discussed, such as algorithm formulation and the development of an aggregated network model and its influences.

**Flow-based Market Coupling (FMC)**

In section 3.3.2 zonal pricing was explained as CM resp. capacity allocation concept, where the network is split into price-zones in the case of congestion on certain flowgates. The proposal of flow-based market coupling (FMC) by the Association of European Power Exchanges (EuroPex) evolved from this market splitting concept. FMC's objective is to coordinate market operation at the day-ahead stage.[48] Despite the assumption, that with market splitting the establishment of different zones is only necessary in the case of congestion, EuroPEX assumes, that the European system can be operated as a number of single-price regions, which will be *linked* through market coupling. Thus, market splitting and market coupling share to some extend the same principles, only the pre-conditions are different, with the European system being historically 'split' and now evolving towards a coupled system. Nonetheless, from this precondition a crucial difference arises. FMC "does not have an integrated market to start with, but only a set of independent markets [...]"[47]. FMC includes two clearing processes. First, the energy market clearing, where the power exchanges in each zone establish a clearing price dependent on net imports, and second, the import and export trades via the interconnections.[47] Nonetheless, market coupling is an implicit auctioning concept as there is no separate bid for transmission capacity. The characteristics of FMC are outlined in [48]. FMC is designed to be able to coexist with forward energy markets and explicit transmission capacity markets.

Although, ETSO and EuroPEX agreed on FMC as one way of cross-border congestion management, the proposal provides a list of still outstanding issues, such as the development of a simplified transmission model and its consequences, the development of the coordinating algorithms, the definition of performance measure etc.[48]

A discussion on the formulation of algorithms and the adaption of market splitting in the highly meshed European network can be found in [49]. Special attention is paid to the integration of transmission bids into the concept, as "at short term time horizon, day-ahead for instance, energy spot market and bilateral trade compete to use the short term slice of transmission facilities through congested networks."[49] The report concludes, that "Transmission bids can be included in a market splitting process[17]."[49] The report also provides an algorithm formulation of market splitting (coupling) using a centralized optimization routine. The objective is to maximize social welfare, subject to zonal power balance constraints, interface power flows and generation limits. A description can be found in [49]. The algorithm is derived from the assumption of a centralized process with all data being available and one entity being responsible for operation. As in [48] the implementation of the algorithm as distributed process remains an outstanding issue. For the implementation of the concept in continental Europe remain, "a number of physical, structural and market based obstacles"[49], such as a highly meshed network where the location of congested lines may change, the interdependency of net transmission capacities and market participants trading bilaterally (OTC-trade). Furthermore, the general role of power exchanges and transmission system operators has to be clarified.

In [48] the need for a regulatory/contractual framework is pointed out, which includes "multilateral arrangements between power exchanges to govern the use of cross-border capacity", as well as, "multilateral arrangements between TSOs to calculate the capacities and flow distribution factors (including the setting up of any central service providers)". The proposed framework allows the coexistence of power exchanges and transmission system operators, which is different from the restructuring developments of the US East Cost, where a pool operator fulfils both functions. A market design with coexisting power exchange and transmission system operator was to be found in the initial Californian market. Both entities were limited in their interactions to a few iterations "in a more or less ad hoc way"[47]. If the interaction between PXs and TSOs are carried out in a similar manner, "then the same difficulties with congestion management that occurred in California might also happen in Europe."[47] Thus, the authors in [47] conclude: "The vagueness of the current text from EuroPEX [...] make it impossible to conclude. Europeans can still choose to go one or the other direction."

**Conclusion**

The three above presented interarea CM concepts all assume that the electricity markets of the Member States are different in a way that integration is not possible.[47] The proposals try to account for this situation by explicitly considering these structural differences. Nonetheless, to the best knowledge of the author, precise information on implementation, such as algorithm formulation, the specification of market rules, transactions involved and necessary mutual agreements is not available so far.

Explicit auctioning is currently used at several European borders, but is claimed to not incorporate parallel flows in the highly meshed European system. [46] Auction practice is diverse[45] and forces market participants to consider various separate transactions in energy *and* transmission markets.

Coordinate auctions and flow-based market coupling are intended to overcome the drawbacks of explicit auctioning, as both methods head towards a unified CM regime in Europe, and thus, may facilitate the creation of the Internal Electricity Market (IEM). However, the European proposals for CM depart from the nodal pricing concept, which is suggested by FERC as standard market design, and may be considered "as benchmark system in the United States".[47] A detailed assessment of coordinated auctions and flow-based market coupling appears difficult as long as the approaches remain specified in a rather conceptual way. Nonetheless, in [50] it is noted that markets, where energy and transmission markets, such as Texas and California were not integrated congestion cost appeared to be high. This argument may be used in favor of implicit approaches, such as nodal pricing and market coupling (splitting). Future research may incorporate the formalization of the ETSO and EuroPEX proposals,

[17] By the time of publication in 2002, the proposed concept was referred to as market splitting

i.e. the formulation of possible algorithms and the simulation of these algorithms with respect to different network topologies and market structures.

## 3.4 Capacity Alleviation Methods

### 3.4.1 Introduction

In section 3.2 capacity alleviation methods and allocation methods were distinguished. Whereas the latter aim at *ex-ante* capacity allocation in the day-ahead stage, alleviation methods are often used to relieve congestion in real-time and are also referred to as remedial actions. As the focus of this report is rather on allocation methods than on capacity alleviation, the analysis is restricted to redispatching and counter-trading, as considered in [41].

### 3.4.2 Redispatching

Above it was outlined that redispatching may be used in conjunction with uniform marginal pricing. In a first phase, market participants are not notified of congestion and energy is traded as if there were no network constraints. If congestion occurs, the system operator alters the generation (load) pattern in order to relieve congestion. Redispatching is exercised as command and control scheme, i.e. the ISO curtails or increase injections without market-based incentives. Redispatching may also be used among different TSOs, which makes close coordination necessary. As generators have to be reimbursed, the ISO has an incentive to keep redispatch cost low. An algorithm formulation can be found in [42].

### 3.4.3 Countertrade or Buy-Back Procedure

"Countertrading is based upon the same principles as redispatching"[41], but may be considered market-oriented. Rather than applying command and control the ISO will buy and sell electricity at prices determined by a bidding process. "The principle of counter-trading is thus a buy-back principle which consists in replacing the generation of one generator 'ill-placed' on the grid as regards the congestion by the generation of one 'better-placed' producer."[51]. Different from market splitting, within the countertrade or buy-back model the market participants only see one uniform price (apart from the participants involved in the countertrade procedure). Equilibrium points of the day-ahead phase remain unchanged. As the ISO has to buy electricity downstream of the congestion at higher cost and sell it upstream, there is no congestion rent, but congestion cost for the ISO. This cost exposure is also regarded as in incentive for investment into grid capacity.[52] Countertrading is used for real-time congestion relief in the Norwegian system and is used as exclusive CM concept in the Swedish market.

## 3.5 Conclusion

This chapter provided an overview of generic market structures and concepts for congestion management. CM concepts were distinguished into capacity allocation and alleviation concept, where the latter are mainly applied for real-time congestion relief. Allocation methods may be differentiated in several ways[18],

[18]CM concepts may be also grouped into explicit and implicit approaches. Explicit approaches establish two markets, one for energy and one for transmission. Hence, market participants have to take transactions in both markets. Implicit auctions integrate the markets for energy and transmission. Thus, capacity is allocated implicitly by energy bids at a specific location within the network.

above an organization into nodal pricing, zonal (area) pricing and uniform pricing was proposed. The characteristics of the concepts have been outlined together with their possible implementation in conjunction with certain market designs. All CM concepts are currently used in electricity markets worldwide. Thus, the next chapter aims at providing an overview of international electricity markets focussing on congestion management.

# Chapter 4

# Implementation of Congestion Management Concepts in Different Markets

*This chapter aims at providing an overview of congestion management methodologies implemented in various electricity markets worldwide. The structure follows the organization of the previous (conceptual) chapter. At first the implementation of nodal pricing models is discussed followed by a section on zonal pricing systems. A summary of uniform pricing models and auction implementation concludes the survey.*

## 4.1 Nodal Pricing Models

### 4.1.1 Introduction

A prerequisite for the implementation of nodal pricing models is the integration of functions related to market and network operation. Thus, nodal pricing models are connected to market designs derived from the pool concept. A central authority (the ISO) operates day-ahead, real-time and financial markets by obeying network constraints. However, a mandatory pool, where only financial bilateral transactions are allowed is not compulsory. Within the markets of the US East coast it is possible to settle into physical bilateral contracts (self-scheduling) and/or to trade through the pool, as long as the ISO is notified of the agreed physical bilateral transactions. The FERC standard market design is based upon this structure. Currently, the PJM, the New York, the New England and the new Californian market rely on this structure. These markets are described briefly below.

### 4.1.2 Pennsylvania-New-Jersey-Maryland Interconnection (PJM)

#### Structural Data

In [7] it is claimed "that PJM operates the world's largest competitive electricity wholesale market." The PJM market covers all or parts of Pennsylvania (PA), New Jersey (NJ), Maryland (MD), DE, OH, VA, WV and the District of Columbia.[7] According to [36] there are 2400 buses and 4000 branches. More than 140 market participants and 80 transmission service customers trade about 8 TWh per month. Energy is produced by 540 sources, consisting of 31% Gas, 21% Oil, 37% Coal, 21% Nuclear, 5% Hydro - 1% of the energy originates from other sources.[53] The PJM market operates as power pool which offers unit commitment and dispatching services to its members. Nonetheless, bidding into the pool is voluntary. Market participants may also opt for self-scheduling.

#### Historical Development

1956 five signatories agreed to coordinate operations and planning as the PJM (Pennsylvania-New Jersey-Maryland) Interconnection.[18] This organization may be regarded as an early example of a power pool. In 1997 PJM started the "first regional bid-based energy market in the US".[36] At this time a uniform marginal pricing system was introduced, which was soon replaced by a nodal or locational marginal pricing system, which is still operational. In April 2002 PJM West joined the marketplace. Thus, two separate control areas now operate under a single energy market.[7] These areas are the largest centrally dispatched control areas in North America.[36]

#### Market Operation and Congestion Management

PJM operates two markets: a day-ahead market and a real-time balancing market. The day-ahead market is voluntary and offers unit-commitment and dispatching services to its participants. Nonetheless, participants may also opt for self-scheduling, and thus, only notify the pool operator about their physical transactions. Transactions in the day-ahead market are binding. This applies also to bilateral transactions which thus can be scheduled at binding congestion charges[1]. A system of financial transmission rights (FTRs) provides hedging opportunities in order to manage the risk imposed by the volatility of nodal prices.

The real-time market as the day-ahead market relies on nodal prices. LMPs are calculated based on the system operating conditions as described by the PJM state estimator.[7] Since the implementation of the current market structure in 2000 there was a strong connection between day-ahead and real-time prices. In the last years the difference has been constantly narrowing. The convergence between day-ahead and real-time prices may serve to some degree as indicator for an adequate market performance. The average day-ahead LMP in 2001 was U.S. $32.75/MWh and the average real-time LMP was U.S. $32.28/MWh.

#### Conclusion

The PJM market may be claimed as performing adequately since the implementation of the current LMP-based market structure.[7, 36] In [54] it is stated, that "Almost everyone agrees that experiences with LMP-based congestion management, in markets where it has been implemented, have been fairly successful." This performance may have influenced other East Cost markets to implement nodal pricing systems, such as New York and New England. In fact, the standard market design of the Federal Energy Regulatory Commission (FERC)[2]relies to a great extend on the PJM design.

### 4.1.3 FERC Standard Market Design

In 2002 FERC published a white paper on a proposed standard market design (SMD) for electricity markets in the US. This SMD is close to the market design of the PJM interconnection[55], although it features distinct elements. The list below is extracted from [54] and [55] and specifies the most important design elements of the SMD.

[1] The congestion charge is defined by the difference in nodal prices

[2] FERC is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.

- Market participation is voluntary
- Provides ability for self-scheduling
- Mandated day-ahead markets for energy using centralized unit commitment
- Locational marginal pricing (LMP)-based congestion management with financial rights to hedge transmission price risks
- Rules for market power mitigation

All elements listed above can be found in the markets in New York, New England and PJM. Additionally, the following design features are proposed for SMD:

- Spinning reserve market
- Marginal losses included in prices
- Electronic dispatch signals sent every 5 minutes
- Automated market power mitigation procedures

The above design elements may be "viewed as a guide on how to establish a wholesale market mechanism that can bring the benefits of competition to all consumers."[54] Furthermore, "SMD should not be viewed as prescription from FERC but rather a reflection of collective wisdom in the industry based on experiences in real markets that have been operating for some time."[54] This viewpoint on SMD explains why the market design relies on the key elements of the PJM market. Thus, the intention of SMD is rather to use knowledge gained by market operation in the past, than to develop a completely new scheme. The transition of the California market from a zonal to a nodal pricing approach may be viewed as a sign that SMD has been influential for market developments in the US. Additionally, ERCOT - the Texas interconnection formed the so called Texas Nodal Team in order to design a nodal market that adheres to SMD.

### 4.1.4 New York (NYPOOL) and New England (NEPOOL)

The above section outlined the main characteristics of the PJM market and the standard market design (SMD) proposal of FERC which is - in its central elements - build around the PJM concept. This concept was also influential for other US markets, such as New York and New England. As the concepts are very similar, a comparison of the markets is provided in the following , featuring two main sections: a) structural data and b) market design.

#### Structural Data

Table 4.2 provides an overview of the generation mix in different US markets. PJM, NEPOOL, NYPOOL and California (will) operate a market close to the SMD recommendations. The fuel mixes in all four markets differ significantly. In this regard one may conclude that the fuel mix can not be identified as key driver for the introduction of locational marginal pricing.

Table 4.1 summarizes the key facts of the NYPOOL, NEPOOL and PJM. While NEPOOL and NYPOOL are rather similar in size, PJM covers an area with a population twice as large. Furthermore, the number of generation sources, the installed capacity exceeds by far the numbers of NYPOOL and NEPOOL. Thus, it appears difficult to identify key drivers from a structural viewpoint. Market size, i.e. installed capacity as well as the total length of transmission lines vary significantly. Nonetheless, LMP was identified as efficient congestion management scheme in all three markets. From the PJM experience one may conclude that even in a system with 2400 buses and 4000 branches the computational requirements can be met to allow for an efficient market operation.

| | New York | PJM | New England |
|---|---|---|---|
| Population | 19 million | 51 million | 14 million |
| Market Participants | 200+ | 200 | 200+ |
| Generators | 350+ | 1082 | 350+ |
| Installed Capacity | 36 GW | 163 GW | 32 GW |
| Peak Demand | 31 GW | 131 GW | 26 GW |
| Transmission Lines | 11000 miles | 56070 miles | 8000 miles |

Table 4.1: Market Key Facts

| | PJM | NEPOOL | NYPOOL | California |
|---|---|---|---|---|
| Gas | 31% | 32% | 90% | 46% |
| Oil | 21% | 28% | 74% | 1% |
| Coal | 37% | 9% | 0% | 0% |
| Nuclear | 21% | 16% | 0% | 9% |
| Hydro | 5% | 12% | 1% | 23% |
| Other | 1% | 2% | 0% | 21% |

Table 4.2: Fuel Mix in Some NERC Regions [53]

#### Market Operation and Congestion Management

Table 4.3 summarizes the key design elements of NEPOOL, NYPOOL and PJM. As outlined above the markets exhibit similar characteristics as all are built around the SMD proposal. One main difference in congestion management and pricing is that in NEPOOL and NYPOOL loads are aggregated into zones, whereas generators are paid nodal prices. Additionally, in the New York area the ISO operates an hour-ahead market which is not present in the PJM and New England area. However, the differences in market design can - to the best knowledge of the author - not be referred to structural features.

### 4.1.5 California

The Californian electricity market has received worldwide attention, especially the energy crisis in 2000 and 2001 has been subject to numerous publications.(See for example [57, 58, 59, 60, 61, 62, 63]) During the energy crisis prices rose to levels ten times higher than usual, so called ‘rolling blackouts’ were experienced and one major utility filed for bankruptcy. For the energy crisis several factors have been identified which are extensively discussed in [57, 58, 59, 60, 61, 62, 63]. This report focussed on factors related to market design, as “the decentralized and zonal market design was perceived as one of the factors that contributed to the energy crisis.”[58] Although, a zonal CM concept was initially applied, the Californian market is discussed within the nodal pricing models as California is soon to transition from a zonal to a nodal framework.[58] Thus, this section describes the key facts related to market design and development, it provides major structural data and summarizes the efforts for the implementation of a nodal pricing system.

#### Historical Development

The early 1990’s in California are characterized as a period of economic recession with electricity prices being 50 percent higher than the national average.[62] Cal-

| | New York | PJM | New England |
|---|---|---|---|
| Number of Markets | Day-ahead, hour-ahead and real-time | Day-ahead and real-time | Day-ahead and real-time |
| Market Products | Locational energy plus four ancillary services | Locational energy plus regulation and spinning reserve | Locational energy plus regulation and spinning reserve |
| Locational Reserve Pricing | Yes | No | No |
| Energy bids | 3-part | 3-part | 3-part |
| Day-ahead unit commitment | Voluntary, central | Voluntary, central | Voluntary, central |
| Congestion Management | Nodal for generation, zonal for load | Nodal for generation and load | Nodal for generation, zonal for load |
| Losses | Marginal | Average | Marginal |
| Integration of Markets | Yes | Partial | Partial |
| Installed Capacity Requirements | Yes | Yes | Yes |

Table 4.3: Comparison of Markets among Northeastern ISOs [56]

ifornia was lacking new significant generation investment proposals and "large customers were complaining" about price levels.[62] Furthermore, "other sectors of the economy like trucking and telecommunications, appeared to be benefiting from less reliance on traditional regulation in favor of more reliance on market forces.[57] Thus, the state was "looking for opportunities to bolster its competitive climate [...], it seemed eminently sensible to at least consider the idea of electricity restructuring at this time."[57]

In 1992 California initiated a planning period, with the so called Yellow Book and Blue Book phases. The Yellow Book was intended to serve as basis for dialogue between all involved parties and did not specify market implementation issues in detail. The Yellow Book included four different strategies, with one strategy named 'D' proposing a "Restructured Utility Industry". This strategy served as basis for the blue book "to lead to direct access of Californian electricity consumers to generation suppliers, marketers, brokers and other service providers in the competitive marketplace for energy services."[57] Influenced by a commissioners' visit to the UK, the blue-book proposal was favoring a spot-market pool, forcing all generators to sell their power into this pool. The proposal stimulated a strong opposition, with advocates of free markets voting for a more decentralized system relying on bilateral trade. The discussion ended in a compromise with all utilities being forced to sell their power via a central power exchange (PX) and the formation of a Californian Independent System Operator (CAISO) which would operate a market for ancillary services and a balancing market. In contrast with, e.g. the PJM system, CAISO would not be responsible to centrally commit and dispatch units. Spot market operation was the responsibility of the PX, whereas functions related to system operation were carried out by CAISO. This separation of market and system operation may be regarded as key difference of the market design advocated by PJM, NEPOOL and NYPOOL. Although utilities had to bid into the PX, and thus, major generation resources were pooled, the Californian market was not a pool market following the understanding of the structure, e.g. in the PJM market. In order to ensure liquidity of the PX spot-market, utilities were not allowed to hedge into bilateral contracts, neither physical nor financial.

The initial Californian market design may be summarized by the following features:

- Separation of spot-market and system operation resulting into the creation of a power exchange and an independent system operator
- Prohibition of bilateral contracts to force utilities to trade all their energy through the PX
- Implementation of a zonal congestion management concept

The last item will be examined in more detail in the next section.

### Market Operation and Zonal Congestion Management

Essentially, two entities were formed to facilitate electricity trade. The California Power Exchange (PX) and The California Independent System Operator (CAISO). With the separation of service related to market and system operation, the appliance of a nodal pricing concept was not feasible. Generation units would self-dispatch themselves, i.e. scheduling coordinators (SCs) would be responsible for balancing the schedules of a group of market participants. The PX may be seen as operating a 'raw' market for electricity[57], not taking into account that energy has not only to be generated but also delivered. The balancing of generation and demand as well as congestion management and providing ancillary services was the responsibility of CAISO. For congestion management market participants had to provide adjustment bids (inc/dec bids), stating for which price they are willing to increase/decrease generation/demand. These bids - along with the "raw" energy bids where submitted to the PX. After the PX stated the market clearing price and quantities, it forwarded the market results along with the adjustment bids to CAISO. CAISO then run computations on whether the market outcome was feasible within the limits of the transmission network without or with adjustment. In the latter case CASIO would use the submitted adjustment bids to relief congestion by altering the initial generation dispatch.

In the Californian transmission system congestion frequently occured on the tie lines between north and south.[57] Thus, initially two transmission zones were defined in order to relief inter-zonal congestion through a zonal congestion management model. Proponents of the zonal model, claimed this concept to balance equity concerns with efficiency goals.[58] Market participants would not face the complexity of nodal pricing concepts, and thus, energy trade would be facilitated being more transparent while effectively unbundling generation and transmission. In California the congestion charge between the two zones was defined by the adjustment bids used for congestion relief. If there is congestion from north to south, the "cheapest available southern generation would be required to produce more power, and the most expensive running northern generators to produce less."[57] The use of adjustment would determine different zonal prices, with the difference of zonal prices defining the congestion charge to be paid by the scheduling coordinators.

In contrast with inter-zonal congestion management, the cost for intra-zonal congestion relief were covered by an uplift charge. This practice founded on the assumption "that intra-zonal congestion is infrequent and insignificant (in terms of financial consequences)."[58] However, the proportion of intra-zonal and inter-zonal congestion cost shifted significantly from 2002 to 2003 (see table 4.1.5). One cause for the cost-shift is the installation of new generation "outside major load pockets mostly in Southern California coupled with new generation at the California/Arizona/Nevada border." This new load flow pattern with its financial consequences is obviously stimulating the transition process from a zonal to a nodal congestion management concept.

| | 2002 | 2003 |
|---|---|---|
| Inter-Zonal | $24,639,084 | $25,684,132 |
| Intra-Zonal | $4,327,625 | $46,536,772 |

Table 4.4: Congestion Cost Comparison for 2002 and 2003

**Proposed Nodal Pricing Approach**

Already after the energy crisis in 2000 and 2001 CAISO was assigned the functions of day-ahead spot-market *and* system operation, as the former separation was identified to contribute to high electricity prices as well as high price volatility. This merge of functions is now concluded by the introduction of a nodal pricing model together with FTRs. With the integration of market- and system-related services, CAISO has the possibility to carry out a security constrained unit commitment (SCUC) and a subsequent centralized dispatch, which not only schedules generation, but also provides locational marginal prices. Thus, the introduction of a nodal pricing system is not only a change in congestion management but also in market organization. Following the recommendations by FERC and the experience made in the PJM, NEPOOL and NYPOOL systems, California is about to migrate to a more centralized market design build around the pool concept.

**Conclusion**

The example of the California market has shown, that an evolution from a zonal CM concept to a nodal may become necessary if intra-zonal congestion cost rise, and thus, it is no longer possible to provide efficient economic signals and to ensure reliable system operation. Moreover, the change in congestion management occurred together with a change in market design. The initial decentralized design is going to be substituted by a centralized concept. The development of the Californian market seems to have significant impact on the general view of market organization in the US. The Californian market evolution rather than structural key drivers may have driven the proliferation of locational marginal pricing together with a pool-based market design.

### 4.1.6 Singapore and Ireland

Above the key features of several US markets have been characterized. The new Californian market, the PJM interconnection, New England and New York rely on locational marginal pricing for congestion management. All systems are build around a pool-based concept, and thus, integrate functions related to market and system operation. The current electricity market in Singapore and the upcoming Irish market follow the same design principles, only exhibiting one major difference: physical bilateral contracts are not allowed. Market participants may only settle into financial hedging contracts. Thus, the Singapore market[64] and the planned Irish market[65] may be seen as mandatory pool-markets, where all energy has to be traded through the pool. Subsequently, the ISO is in charge of clearing the market by obeying network constraints. From an implementation viewpoint, this design reduces transaction complexity for the ISO as no physical bilateral contracts have to be taken into account for the unit commitment and dispatch, but market participants are still able to hedge risk by settling into financial contracts. In both markets locational marginal prices are/will be used for congestion management. The implementation is straightforward and follows the principles outlined for nodal pricing and its appliance, e.g. in the US East Cost markets.

The Singapore market is claimed to perform solidly,[66] and has helped consumers through lower electricity tariffs resulting from efficiency gains in generation and transmission companies.[66]

### 4.1.7 Conclusion

Above international electricity markets have been characterized, which are all build around the concept of pool markets. Nodal pricing is strongly connected to this concept, as locational marginal prices require at a certain time stage the use of a central optimization routine. Nonetheless, pool markets relying on nodal pricing do not necessarily exclude physical bilateral trading. The US East Cost markets and the proposed FERC standard marked design explicitly allow for physical bilateral transactions by using nodal prices and financial transmission rights. As market participants have to notify the pool operator about their physical transactions, the operator is able to take the physical portfolios into account while committing and dispatching generation. In compliance with general market rules, bilateral transactions pay the difference in nodal prices as transmission charge.

In the US the integration of functions relating to market operation and the transmission system may have been stimulated by the collapse of the Californian market, where both functions were assigned to separate entities. The integration is (among others) advocated by Hogan, who claims the pool dispatch and the transmission wires to be distinct essential facilities.[28] From a structural viewpoint, i.e. network topology and generation mix, it appears difficult to identify key drivers for the introduction of nodal pricing. The generation mix in the areas of PJM, New England, New York and California are very heterogeneous.

However, the Californian case has shown, that a market may develop from a zonal to a nodal system, if intra-zonal congestion cost rise during market operation, i.e. cost for intra-zonal congestion relief exceed the cost for inter-zonal congestion relief. Thus, in a topology where congestion is likely to occur at different locations within the network a nodal pricing system may perform more efficient than a zonal system as one prerequisite for a zonal system is an *a priori* definition of the zones which intra-zonal price differences being neglectable.

## 4.2 Zonal Pricing Models

### 4.2.1 Introduction

Section 3.3.2 introduced the principles of zonal pricing which is also known as area pricing, where in case of congestion the market is split in different price zones (areas). In contrast with nodal pricing, zonal pricing does not require a centralized dispatch, market participants may self-schedule themselves. Proponents of zonal pricing, claim the system to balance equity concerns with efficiency goals.[58] Market participants would not face the complexity of nodal pricing concepts, and thus, energy trade would be facilitated being more transparent while effectively unbundling transmission and generation. The next sections focus on two implementation examples: Norway and Nord Pool and Australia.

### 4.2.2 Norway and Nord Pool

The Scandinavian countries share a long history of collaboration in the power systems sector. In January 1996, Norway and Sweden, formed a common electricity market. Finland joined in 1998 and western and eastern Denmark in 1999 and 2000. The central Scandinavian market place is Nord Pool, where day-ahead, real-time and financial markets are operated. Within Norway and Denmark as well as between border interconnection market splitting is used as congestion management concept. In case of congestion different prices apply to the different countries or to the different areas within the countries. The price areas in Norway are called NO1 and NO2, basically they divide the Norwegian power system into a northern and southern part. The splitting involves Nord Pool as responsible spot-market operator and the respective national system operators. In Norway for instance, Nord Pool passes the day-ahead clearing information to Statnett (the Norwegian transmission system operator). Statnett than decides if market splitting is necessary.[67] The process follows the general principles outlined in section 3.3.2.

"Bilateral contracts that span price areas must sell the energy in the supply area and purchase energy in the load area to account for the contribution to congestion, and to expose the contracts to the financial consequences of congestion. It is the only instance of mandatory spot market participation."[67]

To hedge the risk implied by different area prices, contracts for differences are used, where the CfDs[3] used in the Scandinavian market explicitly consider the spatial differentiation of prices. The Scandinavian CfD is defined by the difference between the system price and the respective area price multiplied by the contract volume. In [67] it is outlined that CfDs have similarities with financial transmission rights. While FTRs are used e.g. in the US markets to redistribute the congestion rent collected by the system operator, the Scandinavian CfDs "have no connection to the congestion rent [...]."[67]

Market splitting in the Scandinavian market is used in the day-ahead phase. For congestion relief at real-time counter trading is applied. The implementation of counter trading in Sweden is described in section 4.3.3.

### 4.2.3 Australia

Australias national electricity market started in December 1998. For market operation The National Electricity Market Management Company Limited (NEMMCO) was founded. NEMMCO's responsibility is market operation and power system's management according to the National Electricity Code.[68] The performance of NEMMCO is supervised by the National Electricity Code Administrator (NECA). The Code requires NEMMCO to operate a wholesale spot market, where "NEMMCO must operate a central dispatch process to dispatch scheduled generating units, scheduled loads, scheduled network services and market ancillary services in order to balance power system supply and demand".[68] In that, the Australian market is similar to the pool concept of US markets, Singapore and New Zealand. NEMMCO operates the market in five minute intervals. For every interval a dispatch is carried out, taking into account "any constraints on [...] scheduled generating units, scheduled network services, scheduled loads, ancillary service generating units or ancillary service loads which may result from planned network outages."[68] Furthermore, "NEMMCO must represent intra-regional network constraints and inter-regional network constraints as inputs to the dispatch process." Thus, it would be theoretically possible to apply a nodal pricing system. However, the Australian market is run as zonal system. "For the purpose of conducting the spot market, the market is to be divided into regions recommended by NEMMCO and approved by NECA"[68] Instead of differentiating prices for every node in the system, regional reference nodes are defined. This reference nodes represent five pre-defined zones, being The Queensland, New South Wales, Victoria and South Australia. The rent NEMMCO collects through the difference in zonal prices is called inter-regional settlement residue and is distributed among market participants by the conduct of an auction. "The auction process provides a mechanism for establishing the market value of the residue, and encourages inter-regional trade by providing registered generators, market customers and traders with a mechanism to manage the risk associated with different price

[3] Generally, contracts for differences may hedge temporal risks (as in the UK) or spatial risks (as in Scandinavia).

outcomes between trade regions."[69].

Although Australia and Scandinavia both rely on zonal prices, the system applied in Australia differs significantly from the market splitting procedure of Scandinavia. Zonal prices in the Australian market are the outcome of a central dispatch procedure, where regional reference nodes are defined to represent five zones within the network. In contrast to this centralized computation procedure, zonal prices in Scandinavia are not the outcome of a dispatch process. Thus, Australia and the Nordel System may be seen as two contrasting solutions to zonal pricing. The Australian system relies on the advantages of a centralized market design, while aggregating the transmission system into reference nodes. This simplification may be beneficial for transparent trading. Nonetheless, the Scandinavian system benefits from a more decentralized market organization, which provides more freedom to market participants.

### 4.2.4 Conclusions

Zonal pricing is efficiently applied for the Australian as well as for the Scandinavian electricity market. In Scandinavia in case of congestion the market is split into different price areas, while through arbitrage trading the interconnection capacity is utilized up to its maximum. Although, zonal pricing does not require centralized unit commitment and dispatch, Australia follows an approach were zonal prices are the outcome of a central dispatch procedure. Both systems perform adequately, where the different market design options provide different opportunities for market participants. Nonetheless, considering a zonal pricing system in Europe would require spot-markets within every market area or one coordinated spot market for whole Europe regardless of the chosen implementation scheme.

## 4.3 Uniform Pricing Models

### 4.3.1 Introduction

Uniform pricing models are in place in Sweden and Finland, UMP was also implemented in the electricity Pool of England and Wales. UMP models seem to attract less research as several drawbacks are associated with the pricing system as outlined in section 3.3.3. Generally, UMP appears only appropriate in models with insignificant congestion problems. Implementation issues of UMP are described in the sections below, focussing on England and Wales and Sweden.

### 4.3.2 England and Wales (Pool Design)

The UK electricity market was liberalized in 1990 in an effort to privatize the electricity industry and to introduce competition. The model was often referred to as pool-market, as all energy was 'pooled' in a single market place. Generators bid to the Pool and a scheduling algorithm would perform a merit-order dispatch. The algorithm did not take into account network constraints. The market was treated as one price area. Thus, the UK pool market was based upon uniform marginal pricing as described in section 3.3.3. In the market dispatch phase (day-ahead) market participants are not notified of congestion, congestion is relieved in the so called congestion relief (CR) phase. The cost of congestion relief were recovered through an uplift payment, which in [44] is claimed to be "the least sophisticated part of the Pool's pricing arrangements." This assessment is based on the general drawbacks of uniform marginal pricing models as outlined in section 3.3.3. UMP fails to set locational incentives for generation investment. Furthermore, the cost of congestion relief are rolled-in into a flat-rate (the uplift), and thus, do not differentiate between the contribution of individual generators. A detailed treatment of the uplift, focussing on the components, its calculation and cost developments can be found in [44]. To overcome the problems associated with congestion management and pricing as well as with general market design, the Pool design was replaced in March 2001 by the New Electricity Trading Arrangements (NETA).[70]

### 4.3.3 Sweden

Section 4.2.2 introduced market splitting as day-ahead congestion management concept in Norway and the Nord Pool market. Nonetheless, for intra-zonal congestion relief and real-time operation Norway relies on the counter trading principle, which may seen as market-oriented form of redispatching as described in conjunction with the uniform pricing model. In contrast to Norway, Sweden is solely relying on the counter-trade principle as CM concept. The system operator purchases up- or down-regulation according to the bids in the regulating market. In the market dispatch phase (day-ahead) market participants are not notified of congestion, congestion is relieved in the so called congestion relief (CR) phase. The same system is applied in Finland. In both countries the concept has proven to be adequate.[67] Nonetheless, uniform marginal pricing exhibits several drawbacks as outlined in section 3.3.3. UMP fails to provide locational signals for investment into generation. In Sweden these incentives are provided by a connection charge to the grid which is differentiated geographically. As major load centers are in the South of Sweden, connection charges for loads in the south are higher than in the North, whereas charges for generation in the South are lower to set an incentive for investment.

### 4.3.4 Conclusion

UMP is used only by a few countries worldwide, which have no substantial congestion problems within the transmission system, and thus, the system operator can limit its action to congestion relief through counter trading. In Sweden the lack of incentives is compensated by geographically differentiated connection charges. For networks, where congestion is likely to occur a locational marginal pricing system appears more suitable. In that case cost for congestion relief can be allocated more efficiently, as they are not rolled-in in an general uplift charge but are computed according to congestion contribution. The imprecision in cost attribution may have influenced the UK market to introduce a new market design.

## 4.4 Auctioning of Transmission Capacity

Explicit Auctioning of transmission capacity as described in section 3.3.4 is currently used in several European countries for allocation of transmission capacity on interconnectors. [45] provides a comprehensive overview on specific implementations for several European borders, such as the tie lines between Germany and the Netherlands, Germany and Denmark, France and the United Kingdom, the United Kingdom and Ireland. The diverse use of explicit auctions suffers from several problems, such as increased transaction complexity for market participants, increased complexity for trade involving several interconnections as well as the insufficient consideration of loop flows within the European network. These drawbacks initiated research by ETSO and EuroPEX to propose a comprehensive and unified method for the advancement of a truly internal European electricity market. Coordinated auctioning and market coupling have been characterized in section 3.3.4. These methods have not been applied so far. Thus, implementation examples can not be provided.

## 4.5 Conclusion

The above chapter provided an overview on the implementation of CM schemes in several international markets. It has been outlined that CM exhibits a strong dependence on overall market design. Pool concepts with an integrated entity being in charge for market as well as network operation mostly use nodal pricing schemes for capacity allocation and alleviation. However, the Australian market has shown that with a pool market design zonal pricing is as well possible. In contrast to locational marginal pricing, market splitting does not require a centralized dispatch. Thus, it facilitates to a larger extend the idea of free trade. Nevertheless, a common spot market is needed for the implementation. A prerequisite for zonal pricing is an *a priori* definition of transmission zones. In case of locational changes in the congestion pattern, nodal pricing may perform more efficiently.

# Chapter 5

# Comparison of Congestion Management Concepts

*This chapter concludes the report by briefly summarizing the main characteristics of CM concepts. The comparison aims at showing the dependency of market design and congestion management.*

The preceding chapters have shown that congestion management concepts are strongly connected to overall market design. Generally, markets may be structured ranging from centralized approaches (e.g. pool-based designs) to more decentralized structures, relying more on self-commitment and bilateral trade. Figure 5.1 depicts the scope of organizational solutions for congestion management. Nodal pricing schemes require a centralized dispatch, and thus, are applicable in pool-based markets. Market splitting ranges in between nodal and auctioning concepts. It does not require a centralized dispatch, although a spot market is necessary for implementation. Decentralized concepts such as explicit auctions for transmission capacity allow diverse solutions such as the auction at European interconnectors.

| nodal pricing | zonal concepts | auctioning concepts |
|---|---|---|
| ← | | → |
| centralized design | | decentralized design |

Figure 5.1: Market Design and Congestion Management

The theoretical discussion as well as the description of international electricity markets has revealed, that no general recommendations for congestion management can be given. Certain network topologies, demographic factors and political dialogues influence the implementation of CM concepts in conjunction with overall market design. Key drivers for the implementation of specific concepts could not be identified. The US markets show that nodal pricing can be successfully applied to markets with heterogenous structural features. Other markets relying on nodal pricing are New Zealand, Singapore and Ireland. Zonal pricing schemes are implemented at the moment in Australia, the Nordel area, Texas and California. The latter two will soon migrate to nodal pricing as proposed in the FERC standard market design. Middle Europe with its diverse market structures and explicit auctioning of transmission capacity has followed a different path. Nonetheless, a need for more efficient and effective CM concepts is indicated in [3], where there seems to be a trend towards more centralization and standardization in electricity market products. Table 5.1 summarizes the information related to CM concept, market design and implementation.

| | Main Characteristics | Auctioning | International Implementation Examples |
|---|---|---|---|
| Nodal Pricing | requires a centralized dispatch, often implemented in pool-based markets, high degree of centralization, FTR market for hedging | implicit | PJM, New England, New York, Singapore, Ireland, upcoming market design of Texas and California |
| Zonal Pricing | may be implemented using a centralized dispatch (Australia) or using market splitting (Nordel), in any case zones defined a priori, Cfds for hedging possible | implicit | Australia, Nord Pool |
| Uniform Pricing | congestion not taken into account in the day-ahead phase, redispatch or countertrading for congestion relief | na | Finland, Sweden[1], former England and Wales Pool |
| Explicit Auctioning | decentralized auctioning of transmission capacity | explicit | some European interconnections |

Table 5.1: Summary of Congestion Management Concepts

[1]Although Sweden uses an UMP system, incentives are provided by the geographical differentiation of connection charges as described in section 4.3.3.

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