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Eidgenössische Technische Hochschule Zürich
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Evaluation of Transmission Pricing Methods for Liberalized Markets - A Literature Survey

Internal Report

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Abstract

The report evaluates transmission pricing methods under liberalized market conditions. Several concepts are being discussed, whereas three main categories can be distinguished: rolled-in transmission pricing, incremental transmission pricing and embedded/incremental transmission pricing. In order to clarify the general framework in which electricity trading and therefore transmission takes place, the basic principles of electricity markets are explained in an introductory section.

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1 Introduction

By looking at current publications on electricity markets and liberalization it becomes obvious, that the question is no longer if competition should be introduced but how to organize markets in order to achieve an optimum performance. Power delivery is nowadays a bundle of many services including mainly generation, transmission and distribution. While the former vertically integrated utilities charged one price for power delivery today every single service has to be priced separately.

This report focusses on problems related to energy transmission and its pricing in open electricity markets. Chapter 2 provides general information on the economical principles of electricity markets. It determines the framework in which electricity trading takes places. Chapter 3 explains the main ideas for all discussed transmission pricing methods. Chapter 4 is the main part of the report. Its objective is to give an overview about current methods of transmission pricing, where there are mainly three classes: rolled-in transmission pricing, incremental transmission pricing and embedded/incremental transmission pricing. Chapter 5 summarizes the report and gives a brief outlook on issues not covered within the report.

2 Basic Principles of Electricity Markets

2.1 General remarks

That a countries' electricity market has been liberalized is a very common but likewise unspecific proposition. "Delivered power is a bundle of many services. These include transmission, distribution, frequency control and voltage support, as well as generation. [...] Each service requires a separate market, and some require several markets."[1] Liberalization does not necessarily mean perfect competition and it does not necessarily include all markets reaching from generation to ancillary services. It is obvious, that in reality a clear distinction between the different markets does not exist. But, in order to clarify structures, this report mainly follows the theoretical approach of distinguishing and analyzing single markets.

2.2 Perfect Competition

In [2] it is stated that the theory of perfect competition is well developed but not applicable to the "real" world. The concept is claimed to be an idealized fiction, useful mainly for the conceptual development of ideas.

In this report the theory of perfect competition is used to evaluate the different electricity markets in order to work out how 'close' the real markets are to the optimal (theoretical) structure. The estimation forms the baseline of the further market assessments.[1] The following two questions will be briefly discussed in this section:

- Why is perfect competition favorable?
- Which rules promote perfect competition?

Why is perfect competition favorable?

Perfectly competitive markets are referred to be efficient, where "efficiency means (1) the output is produced by the cheapest suppliers, (2) it is consumed by those most willing to pay for it, and (3) the right amount is produced[1]. Another formulation of efficiency is, that the social welfare has been maximized. A basic example should be suitable to discuss this assertion in more detail.
Elementary microeconomics state that the intersection of the supply and demand curve determine a stable equilibrium in perfectly competitive markets (see figure 1). The demand curve represents the aggregated preferences of the consumers. It defines how much the consumers are willing to consume at a certain price. In contrast, the supply curve shows how much output the suppliers are willing to produce at a given price. From the crossing of both curves the competitive price (or market price) and the competitive quantity can be read.

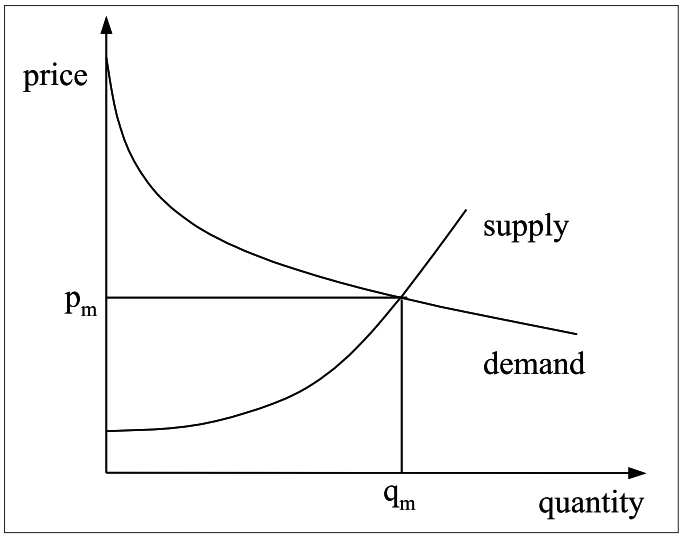

Figure 1: Equilibrium price and quantity in competitive markets

As seen in figure 1 there are consumer who are willing to pay significantly more than the current market price p_m. That difference between the consumers' willingness to pay and their real expenditures is referred to consumers' rent or surplus CS. The same considerations apply to the suppliers side. A number of suppliers had been producing even at a significantly lower price, but, in fact, they are paid the higher market price. The difference on the production side is called producers rent or surplus PS. The sum of both, the consumers' and the producers' surplus is referred to

[1] A similar market assessment is proposed in [3]

total surplus TS. Figure 2 depicts a graphical definition of the terms.

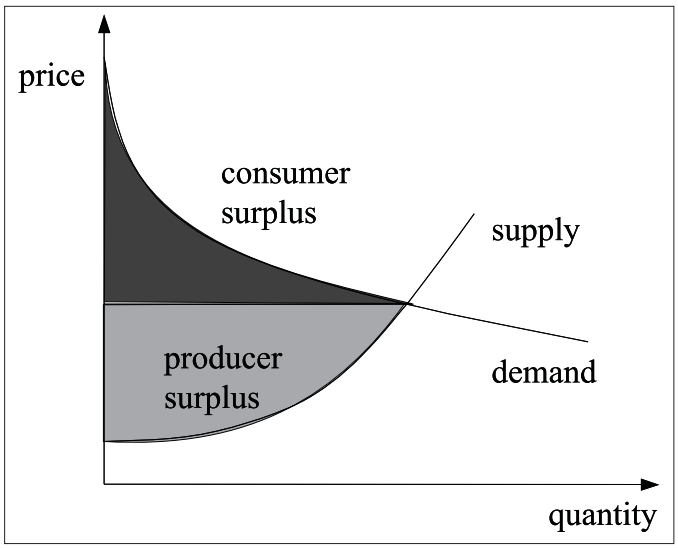

Figure 2: Graphical Definition of Surplus

In perfectly competitive markets the total surplus is maximal, whereas in all other situations (e.g. monopoly or oligopoly) the total surplus is decreasing.[2] Therefore, when competition is introduced to markets, structures close to perfect competition should be implemented.

What rules promote perfect competition?

The following suppositions define the framework for perfect competition:

1 Consumers as well as producers are price takers.

2 Perfect information.

3 Free entry and exit to the market.

4 A homogenous product is produced.

The suppositions will be explained in more detail in conjunction with the markets for energy and transmission (see section 2.3 et seq).

2.3 Energy markets

This section considers a market for the 'direct' trading of electricity. Issues concerning transmission, distribution, voltage support and ancillary services are neglected. It is assumed that loads and generators meet at an ideal marketplace for electricity, whereas generators simply sell and loads buy energy (MWh). How do the rules of perfect competition apply to such an energy market?

[2]A detailed description of the underlying theory can be found in [4].

ad 1) Under 2.2 it has been stated that consumers and producers should be price takers. For the consumer side this supposition is applicable. Usually no consumer has the market power to influence prices. On the production side the situation is different. At least two problems have to be discussed.

- Optimal Plant Sizes
- Market Power

Optimal Plant Sizes

As most production processes, the generation of electricity exhibits large economies of scale. Greater capacities allow to produce output cheaper. From the 1930's thermal plant sizes were increasing constantly while generating cost, were falling. Around 1990 the situation changed with the introduction of Combined Cycle Gas Turbines (CCGT). Generating cost dropped significantly while the efficient plant size plunged to approximately 100 MW (see figure 3).

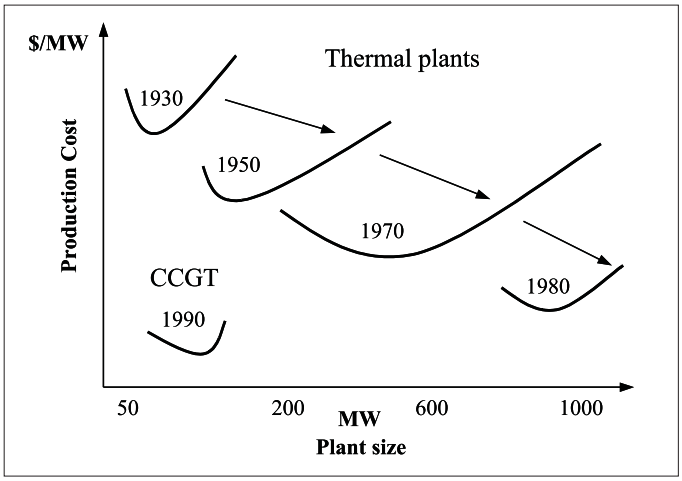

Figure 3: Development of Generation Costs [5]

As a result of this development there will be smaller but more power plants in the generation market. This conclusion can be supported by figure 4.

The trends towards distributed generation supports competition by increasing the number of involved market players and therefore reducing the market power[3] of each single player (see the following paragraph).

Market Power

To assess the feasibility of competition in generation markets, optimal plant sizes are only one integral part. A mathematical measure of market power and the influence on competition is the Herfindahl-Hirschmann-Index (HHI), defined in equation (1).

[3]Market power can be defined as as "the concentration of resources in the hands of a single producer or an insufficient number of producers."[6]

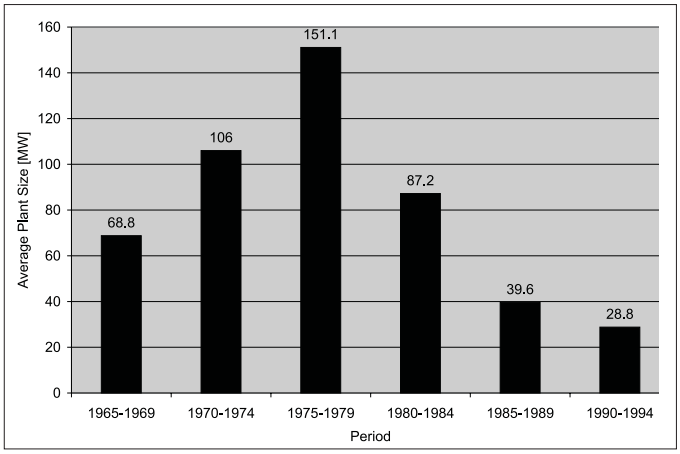

Figure 4: Installed Generation plants average size in the USA

[5]

$$H = \sum_{i=1}^{N} s_i^2 \tag{1}$$

The summation is done over all N market participants. S_i stands for the market share of producer i. Usually the market share is expressed in percent. That leads to a maximum value of 10000 for H. Federal agencies handling antitrust issues consider a market having an HHI of 1800 or more to be highly concentrated. A practical example of the concentration measure is the Scandinavian (Nordpool) market. Taken the Swedish market on its own it is considered to be critically concentrated (HHI=3300). Seen in conjunction with Finland, Norway and the east of Denmark (which form Nordpool) the situation changes. The Nordpool market has a HHI of 1300 and therefore can be seen as sufficient to assure competition.

When putting the two pieces optimal plant sizes and market power together it can be concluded that the introduction of the CCGT technology and the creation of vast interconnected networks have a positive influence on competition by increasing the number of market players and therefore decreasing the market power of each player. Nevertheless no general statement can be made whether generators are in overall price takers (as claimed in supposition (1) for perfectly competitive market) or price adjusters. Every national or international market has to be assessed differently in order to ensure that competition can be promoted.

ad 2) "Perfect information" is a theoretical term. In practice no market participant is able to gather all possible information, but it is been agreed that "the information revolution is the principal reason that competition in energy displacement oligopolies is feasible. Communication control and processing technology have allowed for the dissolution of the vertical structure of the network commodity markets."[2]

ad 3) Through governmental proposals and laws free access to energy trading markets can be promoted. One example is the latest developments in the national European markets (see [7]). Supposition 3 is therefore fulfilled.

ad 4) Electricity can be assumed as a homogenous product. Differences are only possible in terms of additional service agreements (e.g. firm transactions), but those are not considered here. Supposition 4 is fulfilled.

From the above explanations it can be concluded that although limitations exist several national or international energy markets may be suitable for deregulation. Competition can be promoted, as seen in a number of member states of the European Union. Nevertheless, it has to be mentioned that perfectly competitive markets are mainly fiction, as already concluded in [2]. One challenge is how to organize those imperfect markets. Thus, the following sections discuss questions concerning how energy markets should be structured to achieve best for all market players. At least two approaches are conceivable: (1) direct or bilateral electricity trading (2) centralized electricity trading via a power exchange or a pool (see sections 2.3.1 and 2.3.2).[4]

2.3.1 Bilateral Electricity Trading

According to the bilateral trading of electricity suppliers and consumers independently arrange power transaction with each other according to their own financial terms. Economic efficiency is promoted by consumers choosing the least expensive generators.[8] 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'.[9] Figure 5 depicts the bilateral trading approach. As seen several constellations are possible. Generators may only have one load to supply as well as loads may only have one supplying generator.[5] It is presumable that loads settle in contracts with more than one generator and generators deliver electricity to several loads in order to optimize their performance (cp. section 2.5.1).

2.3.2 Centralized Electricity Trading

Within the centralized electricity trading approach no direct transactions between producers and customers are possible. All trading is done via a centralized marketplace (the pool). The method relies on a closed-order-book auctioning system. A central marketplace (pool) operator receives

[4] Direct or bilateral electricity trading is an integral part of the bilateral market model, where centralized electricity trading via a power pool is part of the pool market model. The complete models (including transmission services) are to be found in section 2.5.

[5] "In this case, the generator would schedule its output to follow the customer's load. In all likelihood, this would result in inefficient use of the generator."[10]

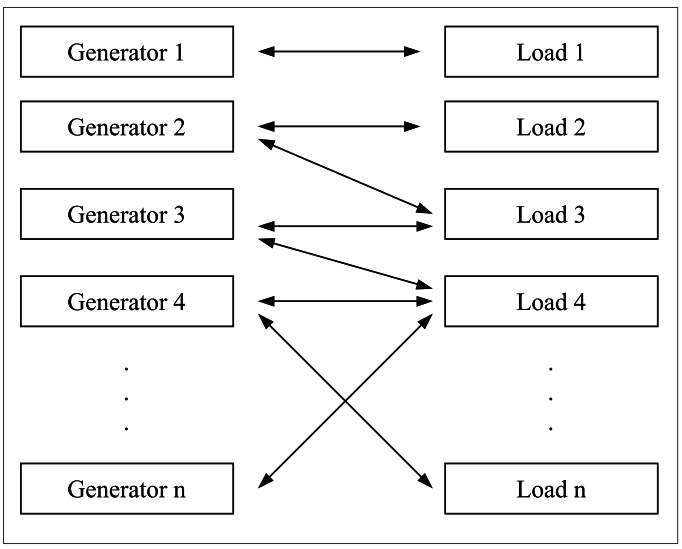

Figure 5: Bilateral Electricity Trading

price and quantity bids for generation and consumption whereas the equilibrium point of supply and demand determines the market clearing price (figure 6). For this model four single stages can be figured out:[11]

1. Bidding
2. Production Planning and Pricing
3. Physical delivery
4. Financial Transactions (Payoffs)

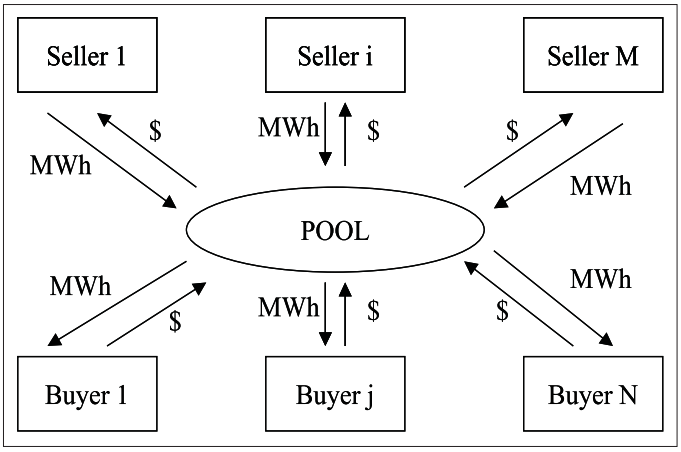

Figure 6: Centralized Electricity Trading [8]

ad 1) Every bidding is made for the day ahead. The day is scheduled in hour or half-hour sections.[6] For every section bids can be transferred to the operator until a fixed deadline. Generators place their production offers in terms of price and quantity for the scheduled sections. Consumers submit their bids relating to the demanded load (resp. energy) and the maximum price they are willing to pay.

[6]In the Netherlands the bidding intervals are set to 15 min.

ad 2) When the orderbook is closed the pool operator calculates the market clearing price (p_m) and the market clearing quantity (q_m) for every scheduled section (hour or half-hour) the day ahead. The market solution or equilibrium is set by the intersection of the supply and demand curves. Whereas the last unit produced sets the market clearing price also referred to the system marginal price (SMP), which is applied to every generated unit (figure 7).

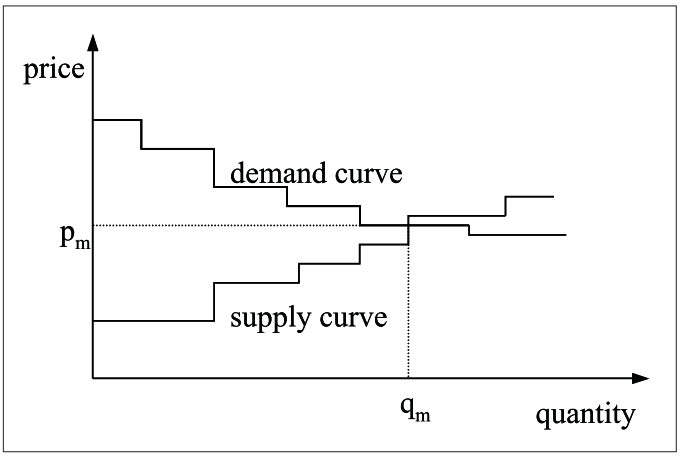

Figure 7: Pricing in a Pool Market [12]

ad 3) After all trade has been settled for day $(n-1)$ the physical delivery takes place on day (n). The delivery contracts are fulfilled according to the before agreed terms concerning scheduled times, peak power and quantities.

ad 4) The last stage of the pool model process refers to financial transactions. The buyers pay the Pool Operator the consumed energy, whereas the Pool Operator pays the generators the injected energy. To all participants the system marginal price is applied.

2.3.3 Conclusions

The above sections provided information on energy markets. Transmission, distribution as well as ancillary services have been neglected. It was stated that energy markets are suitable for deregulation, while there are different approaches of organizing the market. Solutions range from direct, bilateral settlements between generators and loads to the trading of energy via a supervised pool. A system were both approaches coexist was introduced in the UK in 2001. The New Electricity Trading Arrangements (NETA) allow for bilateral contracts as well as energy trading via a power exchange.

2.4 Transmission Markets

When looking at current structures in several countries, it is obvious that transmission markets of electrical energy

are still regulated. In the US as well as in Scandinavia and Germany a System Operator exists which is (among other duties) in charge of aligning the whole network transmission services.[7] At least two questions arise. What is so special about electricity transmission that it is still regulated? Why is a supervising organization, such as a System Operator, needed?

2.4.1 Transmission Markets and Competition

In supposition 3 for perfect competition it was stated (see section 2.2), that free market access should be guaranteed. When looking at transmission markets that prerequisite is not fulfilled. Due to historically developed structures in the utilities industries vast transmission and distribution grids belong to one company. In Germany six companies own the complete transmission network.[13] For potential market participants it is not possible to enter the transmission market due to infrastructural as well as financial barriers. The start-up costs would be extraordinary. That situation can not be referred to a competitive structure. Why did such conditions developed?

In section 2.2 prerequisites for perfectly competitive markets were outlined. One supposition has to be added:

5 No large economies of scale.

In the following paragraphs it will be explained what economies of scale are and how they influence market structures.

Economies of Scale

Economies of scale are strongly connected to a company's or industry's cost structure. To deliver a consistent explanation, it is necessary to have a closer look on cost types and functions first. When a firm manufactures a product, it is, in the short run, usually faced with two different cost types: variable cost $c_v(y)$ and fixed cost F. They both make up for the total cost. Only the variable cost change with the output y, while fixed costs can, in the short run, not be influenced by the company. They have to be assumed as given through certain factors and circumstances regarding to existing production facilities (see equation 2).

$$c(y) = c_v(y) + F \tag{2}$$

The cost of producing one unit of output are referred to average cost AC (see equation (3) and (4).

$$AC(y) = \frac{c(y)}{y} = \frac{c_v(y)}{y} + \frac{F}{y} \tag{3}$$

$$AC(y) = AVC(y) + AFC(y) \tag{4}$$

with:

$AVC(y)$	average variable cost
$AFC(y)$	average fixed costs

Figure 8 shows how the AC behave depending on the output. AFC are falling with an increase in production, while AVC may at first be constant or even drop (not displayed in figure 8) due to possible organizational improvements, but in the long run AVC will escalate because of factor limitations.

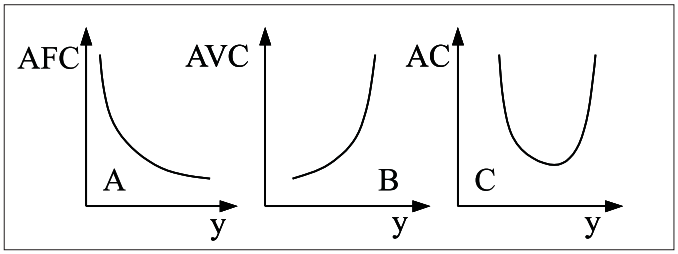

Figure 8: Average Cost Functions [4]

One way of characterizing economies of scale is with decreasing average cost over the output. As seen in figure 8 it is somewhat 'natural' that economies of scale will occur. Average Cost will decrease to a certain point with the output increasing (To be seen in the first part of the u-curve). The more important question is to what extend economies of scale can be gained. From part A of figure 8 it can be read that AFC are falling constantly with higher production levels. When there are large fixed cost and relatively small variable cost, they effect of decreasing AFC will outweigh the effect of increasing AVC to a much higher level. The minimum of the AC curve is "travelling" to the right. This structure results in large economies of scale, given the opportunity to adjust the production at the minimum of the cost function.

Minimum Efficient Scale (MES)

In the above paragraph it was stated that economies of scale can be characterized with decreasing average cost over the output. When making long run decisions, a company will build production facilities adjusting the level of output where the average cost are minimal. This is referred to the minimum efficient scale (MES). In case of small economies of scale the MES will be rather small, whereas large economies of scale favor larger production facilities. In figure 9 two different structures regarding possible MES and market sized are displayed. In part A of figure 9 the MES is rather small so many firms are able to operate in the market in order to serve demand. Part B depicts a situation where the MES is larger than the total market demand. Geometrically, this means that the minimum point of the average cost curve is to the right of the demand curve.[14] This structure is called a natural monopoly.

Conclusions

By looking at the market for the transmission of elec-

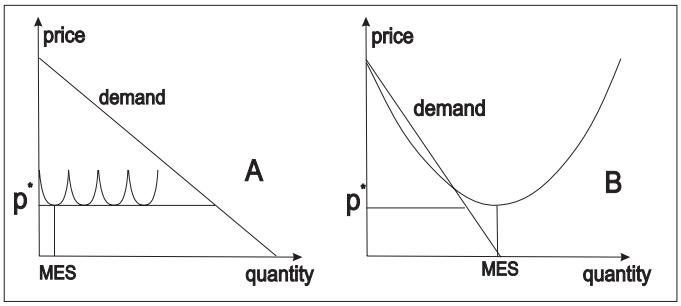

Figure 9: MES and market size
[14]

trical energy it can be concluded that it is a natural monopoly.[1] Fixed costs are high while variable costs are comparably low. Monopolies transmit energy at significantly lower total cost than the best 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."[15] Under such conditions, conventional wisdom suggests that government regulation must substitute for competition to discipline the behavior of firms. Deregulation would not be suitable.

2.4.2 Approaches for Regulating Natural Monopolies

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.

ad 1) The idea here is that suppliers recover their costs (including a specified rate of return) but nothing more. "Perfect COS regulation holds prices down to long-run costs but takes away all incentives to minimize cost." Saved money from innovations is taken away by the regulator and directly given to the customer.[1]

ad 2) Price-cap regulation sets a cap on the supplier's price according to some formula that takes account of inflation and technical progress.[1] This formula or rate is often referred to rate-x. The method sets better incentives than COS. Money saved from innovation or improving of production efficiency is kept by the supplier.

2.4.3 The System Operator Service

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."[1] 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.

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.

It has to be mentioned that different countries follow different approaches in organizing the transmission market. Above it has been stated that there is generally one network-owning monopolist in a national transmission market offering transmission and ancillary services as well as fulfilling objectives as a System Operator. That would be called a nationwide TransCo. This structure can be found in the Swedish and Norwegian market but not in the US or Germany. A country may be split into certain, historically developed regions. For each area there is a regulated transmission monopolist (TransCo), owning the network and coordinating its local market while the countrywide coordination is done by an Independent System Operator.

Although the structure of transmission markets may differ from country to country, there are four core objectives in order to keep the market functioning.

1 provide a non-discriminatory access to the grid

2 offer a reliable, efficient and environmentally adapted transmission of power on the grid

3 keep the system in balance

4 provide ancillary services (reserves, black start possibility, voltage and frequency control)

This report does not focus on point 4. Regarding point 2 only one aspect is covered: possible methods for the pricing of the transmission service (see section 4). Keeping the system in balance (point 3) creates another market: the regulating or balancing market. The System Operator has to buy energy from suppliers when demand exceeds generation or has to schedule loads for compensating when generation exceeds demand. A comprehensive treatment of the regulatory or balancing market can be found in [16].

2.5 Practical Market Models

In a vertically integrated industry delivered power was a bundle of several functions. Under liberalized conditions the former functions (or services) appear to be separate markets. An essential question arises in how to practically organize the different markets to continue the high-quality power supply.[17] Potential market models must be defined to meet the following tasks:[17]

Task 1 Meet the given predicted time-varying demand at minimum operation cost.

Task 2 Compensate for transmission losses (real and reactive) that occur in the system as the predicted demand is supplied.

Task 3 Meet various operating constraints (such as thermal or stability constraints on transmission lines, voltages at both demand and supply buses).

Task 4 Provide flexible generation in real-time to balance deviations from the anticipated demand, as they occur

Task 5 Provide stand-by networks resources (active and reactive power) in case any single outage occurs on the system (n-1 security criterion)

The following sections provide examples on proposed models for the arrangement of generation and transmission markets considering the above tasks.

2.5.1 The Bilateral Model

Figure 5 depicted the process of bilateral electricity trading. In order to include the transmission service the model can be extended as seen in figure 10:

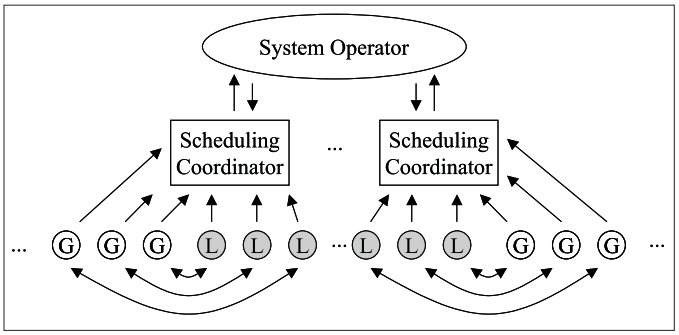

Figure 10: Bilateral Model

In [10] it is stated that the further development of the bilateral trading model is a 'logical evolution'. Scheduling coordinators "'pool" a variety of generating resources to meet the combined loads of multiple customers.[10] Additionally, they are in charge of balancing generation and demand of market participants in a certain area and submitting the preferred schedules to the System Operator. Employing Coordinators for a number of loads and generators means improving efficiency of the regional network usage, whereas the System Operator is responsible for optimizing the grid as a whole. Thus, both entities are directly associated with the coordinating of the transmission services.

2.5.2 The Pool Model

Figure 6 depicts the process of centralized electricity trading. No direct transactions between sellers and customers are possible. All energy is traded via the Pool. 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

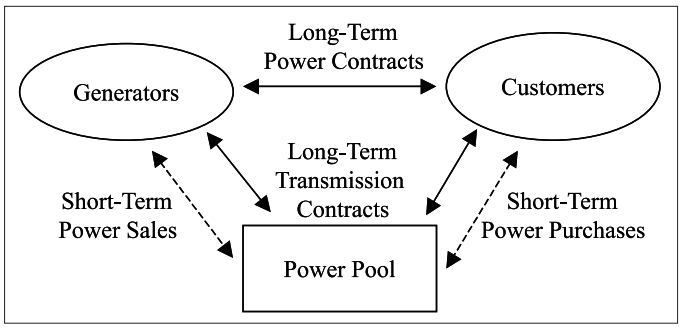

Figure 11: Coexisting Pool and Bilateral Model [19]

essential facilities.[18] Thus, the Pool Operator carries out all functions relating to the centralized marketplace (the pool) and beyond fulfills objectives as a System Operator (see section 2.4.3).

2.5.3 Coexisting Bilateral and Pool Structures

The above sections provided an overview about the pool and the bilateral model as two implementations for electricity markets. To some extend both models may coexist. Suppliers and customers settle in long-term mutual contracts to hedge price risks whereas the remaining generation and transmission capacity is traded at short-term markets (figure 11).

As seen in figure 11 customers and generators write long-term power contracts which each other, while they subsequently have to settle in long-term transmission contracts with the power pool.[7] The pricing mechanism of the pool market would then be modified as depicted in figure 12. The inflexible area results from the existing bilateral contracts.

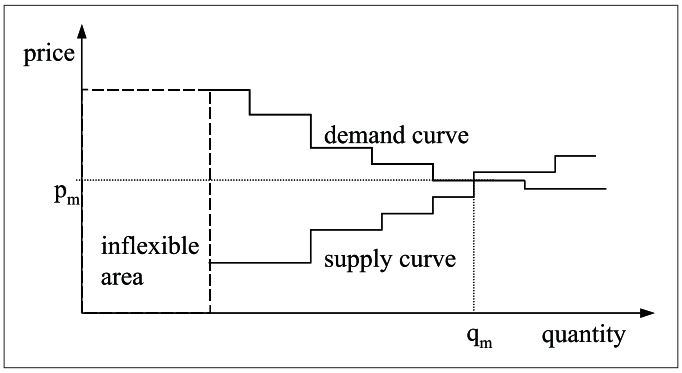

Figure 12: Modified Pricing Mechanism in Pool Markets

When there are no physical, bilateral transactions 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

[7] Here the underlying assumption is, that the power pool fulfills the role of an ISO.

at a price p at some future time, they may enter into a CFD." [20] 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 13 shows the financial transactions between the buyer, the seller and the Pool Operator. Crucial to CFDs is the underlying spot market, where the purpose is to eliminate uncertainty in temporal spot price variations.[20]

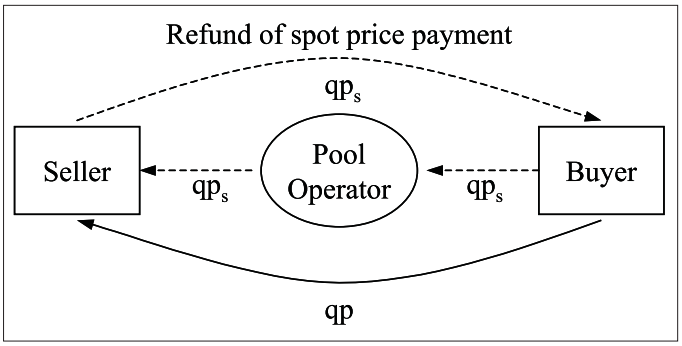

Figure 13: Contracts for differences [20]

2.5.4 Bilateral Structures and Power Exchanges

The structures in sections 2.5.2 and 2.5.3 premised the existence of a pool operator who's main objectives are to make the pool market work and to ensure the reliability of the transmission network by scheduling all network services. Although both functions are strongly connected and Hogan concludes in [18] that they are very likely to be carried out by one entity a different approach is conceivable. The customers may settle in long- and medium-term bilateral contracts while in the short-term energy is traded via spot markets at power exchanges[8] (figure 14).

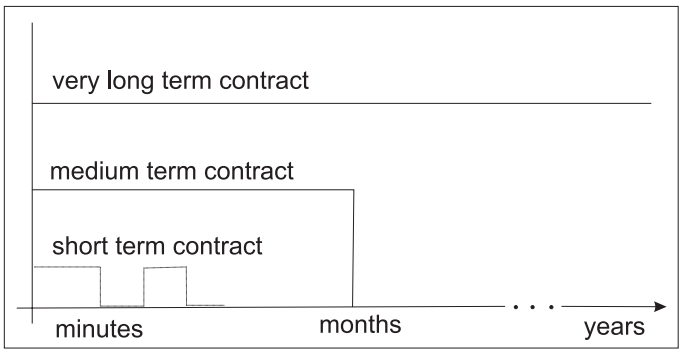

Figure 14: Contractual Processes of Interest [17]

The pricing mechanism of the power exchange's spot market is similar to the one applied in a pool market (see section 2.3.2). Generators and loads place their bids one day ahead, while the exchange operator calculates the system price on an hour- or a half-hour basis. The key difference to a pool market is the amount of energy traded. When the market focus is on bilateral competition the proportion of traded energy at the power exchange may be rather small compared with the market volume. The exchange operator does not 'see' the whole network's generation or load schedules. In that case it is insufficient to assign the functions of an ISO to the exchange operator. The spot market may here just be seen as market supplement to make competition work.[9]Hence, the network is managed introducing the same mechanism as in the bilateral model. Scheduling Coordinators submit the generation and load forecasts of their assigned areas to the ISO. This procedure also applies to the power exchange. In Germany the above approach is implemented. The market relies on decentralized trading structures (bilateral competition), where scheduling coordinators (Bilanzkreisverantwortliche) and an ISO are employed. The power exchange is situated in Leipzig (LPX - Leipzig Power Exchange).

2.5.5 Conclusions

The above explained models may be seen as specific implementations of four general design principles for electricity markets:[17]

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.

As stated in [17] the principles may serve as approved competitive structures for the trading of electricity.

2.6 Conclusions

The above sections delivered the basic principles of electricity markets. It was stated that delivered power is a bundle of many service, including at least generation, transmission, distribution and ancillary services. For each service a separate market exists. Common market models as the pool and the bilateral model do not cover all aspects of power delivery. Very little information on the transmission

[8]Here the term power exchange is used only in connection with its spot market. This does not include the financial market (futures, forwards, etc.)

[9]In [15] it is emphasized that a spot market is crucial for promoting competition. Even for market participants only willing to write bilateral contracts the pricing structure at the power exchange may serve as information basis.

of electricity is given, while power transmission forms another market that appears to be a natural monopoly. In order to promote efficiency the monopoly has to be regulated either using perfect cost of service regulation (COS) or price cap regulation. Whereas the degree of regulation depends on the monopolist legal form (non-profit or for-profit-entities). The monopolist fulfills crucial tasks for the functioning of the electricity market as a whole. One objective is to offer a reliable, efficient and environmentally-adapted transmission of power on the grid. Thus, section 3 and 4 put emphasis on the pricing of the transmission service.

3 Introduction to Transmission Pricing

When discussing transmission pricing, it is necessary to define what is meant by or included in the transmission service. In [21] the following definition is given: "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." For cost recovery the customers (generators and/or loads) have to be charged a price, which has to be defined clearly to allow correct economic and engineering decisions on upgrading and expanding generation, transmission and distribution facilities. Thus, the pricing of the transmission service must meet the following requirements:[22]

1 Promote economic efficiency

2 Compensate grid companies fairly for providing transmission services

3 Allocate transmission costs reasonably among all transmission users, both native load and third party

4 Maintain the reliability of the transmission grid

Contradictory to the above statements about transmission pricing in [15] it is claimed that "there is no separate transmission service in an integrated locational energy market and hence there is no separate price for such a service. Ruff states that the price for moving energy from point X to point Y is simply the difference in energy prices between the two points. Section 4.2.2 explains the concepts behind this idea (spot pricing theory). Apart from that viewpoint the methods in section 4.1 premise the existence of a separate transmission service and therefore the need for transmission pricing. To promote a better understanding of the different pricing methodologies section 3.1 makes some general amendments regarding costs and prices in structural inefficient markets such as natural monopolies.

3.1 Pricing and Market Structures

In section 2.4.1 it was outlined that the transmission market exhibits many characteristics of a natural monopoly. This structure differs from perfectly competitive markets, which are often taken as base case when discussing market structures. Thus, in section 3.1.1 the pricing mechanism in perfectly competitive markets will be explained as basis for the assessment of natural monopolies (see section 3.1.1).

3.1.1 Pricing in Perfectly Competitive Markets

Figure 2.2 depicted the equilibrium solution in perfectly competitive markets. It is given by the intersection of the supply and demand curve. What else can be said about the market clearing price p_m and quantity q_m? One crucial supposition for perfectly competitive markets states that producers as well as consumers should be price takers. No action either from producers or consumers will influence the market price. The market participants assume the price as given. When talking about profit-maximizing producers the only choice to influence their profit π is to adjust the level of output[10] Where the profit is defined as follows:

$$Profit = Revenue - Cost \tag{5}$$

$$\pi = pq - c(q)^{11} \tag{6}$$

The producers' profit maximizing problem is defined in equation (7).

$$\max\{pq - c(q)\} \tag{7}$$

Equation (8) states the first order condition for the maximization in respect to q.

$$p = \frac{dc(q)}{dq} \tag{8}$$

The right side of equation (8) represents by definition the marginal cost[12]. Thus, at the equilibrium point the price equals the producers' marginal cost.[13] In addition to the mathematical approach, the first order condition can also be gained by analyzing the producers behavior. The problem to solve is, which output level to choose for maximal profit. It is obvious that the producer will operate at the point where the additional revenue from selling one more unit (also referred to marginal revenue) equals the marginal cost. At any other point the producer would be able to increase his profit by selling additional products. On perfectly competitive markets the equilibrium

[10] When talking about production for the output level the variable y is used, while in connection with markets for the quantity the variable q is common. In the following sections q and y will be used in parallel.

[11] see section 2.4.1 for a detailed explaination of the cost function

[12] The marginal cost $MC(q)$ measure the change of the total cost $c(q)$ for a given change in the output q.

$$MC(y) = \frac{dc(q)}{dq} \tag{9}$$

Often the increase of the output is set to one unit, in that case the marginal cost will reflect the cost of producing an additional unit.

[13] see [4] for a detailed description of the underlying microeconomic theory.

price equals the producers' marginal revenue. This can easily be gained from another consideration. Equation (10) shows how much additional revenue dR the producers is able to collect when marginally changing the output q.

$$dR = p \cdot dq \tag{10}$$

Though the price is assumed given, it is defined as:

$$p = \frac{dR}{dq} \tag{11}$$

The right side of equation (11) is by definition the marginal revenue. The equilibrium point is then characterized by:

$$p = \frac{dR}{dq} = \frac{dc(q)}{dq} \tag{12}$$

Adding the information from section 3.1.1 the following conclusions can be drawn:

- the intersection of the supply and demand curve sets an equilibrium
- the equilibrium price equals the producers' marginal cost and the producers' marginal revenue
- the total surplus in perfectly competitive markets is maximal

The above considerations are valid for perfectly competitive markets, but can not be applied to natural monopolies. In contrast, section 3.1.2 describes the pricing mechanism in natural monopolies.

3.1.2 Pricing in Natural Monopolies

A crucial measure for natural monopolies is the minimum efficient scale (MES). It is defined by the average cost curve (see figure 9). As seen in section 3.1.1 at the equilibrium in perfectly competitive markets the price equals the marginal cost, but how are marginal cost and average cost related? From figure 15 it can be read that the marginal cost curves crosses the average cost curve at its minimum. This can be mathematically supported as follows:

$$MC(q) = \frac{dc(q)}{dq} \tag{13}$$

$$AC(q) = \frac{c(q)}{q} \tag{14}$$

The minimum of the average cost curve is calculated as seen in equation (15) (first order condition):

$$\frac{dAC(q)}{dq} = \frac{q\frac{dc(q)}{dq} - c(q)}{q^2} = 0 \tag{15}$$

After substituting the relevant terms with the definitions in equations (13) and (14) we get:

$$\frac{MC}{q} - \frac{AC}{q} = 0 \tag{16}$$

which leads in the end to:

$$MC = AC \tag{17}$$

Figure 15 depicts a natural monopoly situation including the different cost curves.[14]

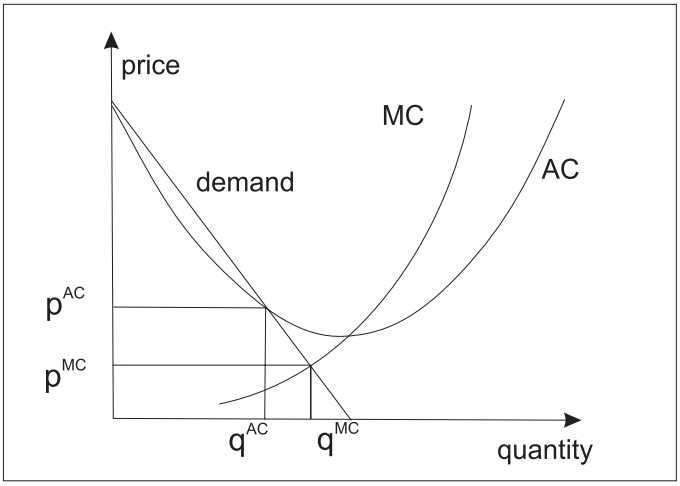

Figure 15: Pricing in a Natural Monopoly [14]

"Producing the output q^{mc} at price p^{mc} would be efficient, but the profit is negative."[14] The monopolist would recover its costs at point (q^{ac}, p^{ac}) but in that case the produced quantity q^{ac} is not sufficient to satisfy the market. In any case there will be a loss of social welfare. Common wisdom suggests that this market has to be regulated, where one approach is to allow the producer to produce at (q^{ac}, p^{ac}) to cover its costs with having the disadvantage of a production deficit. The second approach is to let the government operate the natural monopoly at point (q^{mc}, p^{mc}) where the negative profit is subsidized by a lump sum subsidy. "The problem in both cases is to determine the true cost of operation."[14] Hence, several pricing paradigms have been proposed, where "transmission pricing paradigms are the overall process of translating transmission costs into overall transmission charges. The goal of these pricing schemes is to allocate and/or assign all or part of the existing and the new cost of transmission to the [...] customers."[23]

3.2 Transmission Pricing Paradigms

The report follows the paradigm structure proposed in [24]. Three main paradigms are distinguished:

1. Rolled-In Transmission Pricing Paradigm
2. Incremental Transmission Pricing Paradigm
3. Composite Embedded/Incremental Paradigm

[14] For visibility reasons the demand curve in figure 15 is assumed to be linear

3.2.1 Rolled-In Transmission Pricing Paradigm

In the Rolled-In Pricing Paradigm all cost are summed up (rolled-in) into a single number. Cost types are not distinguished. All cost components are included. The sum of cost is allocated to the various system users. Therefore it is necessary to define the "extend of use" of the transmission system by every user. Several methods have been proposed:

1. Postage Stamp
2. Contract Path
3. Distance based MW-Mile concept
4. Power flow based MW-Mile concept

The methods are being discussed in section 4.1 Figure 16 provides a schematic of the rolled-in paradigm, whereas embedded costs are defined as the revenue requirements needed to pay for all existing facilities plus any new facilities added to the power system during the life of the contract of the transmission service.[25]

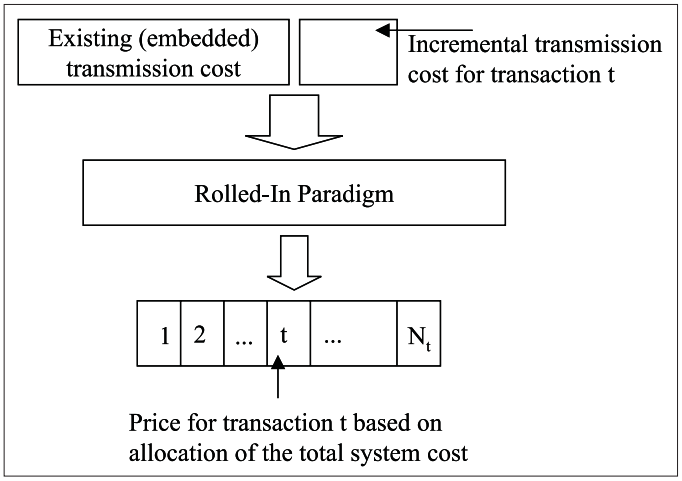

Figure 16: Rolled-In Pricing Paradigm [23]

Albeit the rolled-in transmission pricing paradigm is popular among the grid companies it is considered to be economically inefficient since it ignores transmission resources scarcity.[24] More details are given in the specific method sections (see section 4).

3.2.2 Incremental Transmission Pricing Paradigm

To get an understanding of the Incremental Transmission Pricing Paradigm it is necessary to define incremental costs. They are referred to the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer.[25] According to the paradigm the customer pays the full cost for any new facilities that the transaction requires, i.e. the incremental cost. To calculate incremental transmission prices the following methods have been proposed:

1. Short-run incremental cost pricing (SRIC)
2. Long-run incremental cost pricing (LRIC)
3. Short-run marginal cost pricing (SRMC)
4. Long-run marginal cost pricing (LRMC)

The concepts are described in chapter 4.2. Figure 17 shows a schematic of the incremental transmission pricing paradigm, where the existing system costs are still to be covered by the present (old) customers.

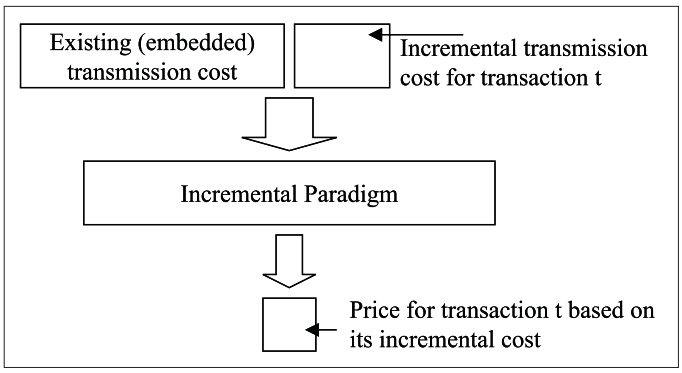

Figure 17: Incremental Pricing Paradigm [23]

In contrast to the rolled-in pricing paradigm the incremental pricing paradigm is considered to promote economic efficiency, although it is a complex to implement.[23]

3.2.3 Composite Embedded/Incremental Transmission Pricing Paradigms

The composite pricing paradigm includes the existing system costs and the incremental costs of transmission transactions. The two components of the charge are calculated throughout the methods described in sections 4.1 and 4.2. Figure 18 shows the concept. The composite transmission pricing paradigm may eliminate most of the problems of the rolled-in and the incremental pricing paradigm.

3.2.4 Conclusions

The above sections provided an introduction to cost based transmission pricing paradigms. The objective of the different paradigms is to "translate" transmission costs into prices.

4 Transmission Pricing Methods

This section describes the specific transmission pricing methods, whereas the methods are to be seen as implementations of the paradigms. In general transmission pricing methodologies determine transmission prices for individual transmission customers. Two main categories according to the paradigms can be distinguished: rolled-in pricing methods and incremental pricing methods.

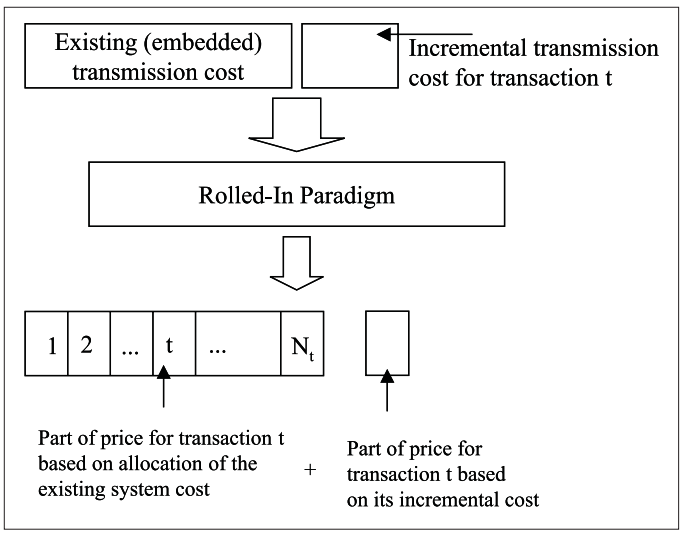

Figure 18: Composite Embedded/Incremental Pricing Paradigm [23]

4.1 Rolled-In Pricing Methods

Rolled-in methodologies refer to the rolled-in transmission pricing paradigm. The total costs are allocated to the system users. Five different methods are described below.

4.1.1 Postage Stamp Methodology

"A postage stamp rate of transmission service may be calculated by summing up all transmission cost and divide it by system peak demand thus producing a flat amount per MW"[26]. The customer transmission charge is given by the peak demand involved in the customer transaction multiplied with the postage stamp rate (see equation (18)).

$$R_t = TC \cdot \frac{P_t}{P_{Peak}} \tag{18}$$

with:

R_t	transmission price for transaction t
TC	total transmission charges
P_t	power of transaction
P_{Peak}	system peak power

Transmission losses are treated separately and born by the purchaser of the transmission service.[27] In [28] a modified postage stamp tariff is proposed, where four components are distinguished:

1 individual cost component: covering connection cost, metering and billing

2 demand component: covering maintenance, general improvement of the grid, black start capability

3 energy component: covering reserve and reactive power

4 marginal loss component: covering the cost of compensating for grid losses

A comprehensive treatment of the proposed method can be found in [28]. In general, the postage stamp method is considered sending incorrect economic signals.[15] A transaction with generation and load in short electrical distance would cross-subsidize a transaction with heavy system usage (long electrical distance between injection and receipt). Besides, the customer pays a fixed price independent from the specific network situation. Constraints or bottlenecks are not taken into account. However, the calculation is very easy and therefore often used throughout the utilities industries.[13]

4.1.2 Contract Path Methodology

Within the contract path method the transmission service provider and the customer agree on a fictitious path (contract path) for the transmission service. The contract path interconnects the points of injection and receipt, although it is defined "virtually" without power flow studies. Once the contract path has been determined all or a part of the transmission cost related to the specified path are assigned to the transaction. To do so the grid operator has to know all concluded bilateral contracts to determine the extend of usage of the single transactions.

Compared with the postage stamp method the contract path concept takes the distance between injection and consumption into account. Nevertheless the method is likely to provide wrong economic signals since the contract path is fictitious and not dependent on the real network situation. The "real" path may differ in terms of distance and affected lines. Transaction cost may strongly vary and therefore cause cost as well as network inefficiencies.

4.1.3 Distance based MW-Mile methodology

According to the distance based MW-Mile methodology the embedded transmission charges are assigned to the customer[16] based on the airline distance (mile distance) between injection and receipt and the magnitude of transmitted power (MW).

$$R_t = TC \cdot \frac{PX_t}{\sum_i PX_i} \tag{19}$$

with:

$$PX_t = DT \cdot PM \tag{20}$$

where:

[15] A detailed case studies showing the instability of the postage stamp method is done in [29].

[16] Customers are referred to generators or loads. Thus, it has to be decided who has to pay the transmission charges. Three characteristics are possible: (1) all charges are assigned to the generator (2) all charges are assigned to the load (3) the transmission charges are shared between the generator and the load.

PX_t	MW-Mile Value
DT	airline distance
PM	power magnitude
TC	total transmission charges

To this method in general all drawbacks of the above concepts apply. The actual network conditions are neglected. The airline distance as well as the contract path do not account for the "real" transaction path. Wrong economic signals are most often be provided.

4.1.4 Power Flow Based MW-Mile Methodologies

The power-flow based MW-Mile method is the first concept to consider the real network conditions using power flow analysis, forecasted loads and the generation configuration. The cost allocated to the customer is calculated on the basis of the "extend of use" of each network facility. Several sub-concepts have been proposed:[29]

MW-mile (MWM)

Equation (21) shows the cost allocation principle of the MW-mile methodology.

$$R(u) = \sum_{allk} C_k \frac{|f_k(u)|}{\bar{f}_k} \tag{21}$$

$R(u)$	allocated cost to customer u
C_k	cost of circuit k
$f_k(u)$	k-circuit flow caused by customer u
$\bar{f}_k$	k-circuit capacity

In a first step the flow on each circuit (line) caused by the generation/load pattern of each customer has to be calculated based on a power flow model. Cost are then allocated in proportion to the ratio of power flow and circuit capacity.[29]

Since this method allocates transmission cost through a ratio of the power flows caused by the customers and the line capacity not all embedded cost may be recovered. The total power flows are usually smaller than the line capacities. The method does not cover the cost for holding reserve capacities. Only the 'base case' is evaluated. Additionally, the method is said to be not solidly grounded on economic theory.[29]

Modulus Method (MM)

Relating to the Modulus Method the line capacities are replaced by the absolute power flows caused by all customers in order to fully recover the embedded cost. Equation (22) shows the substitution.

$$R(u) = \sum_{allk} C_k \frac{|f_k(u)|}{\sum_{alls} |f_k(s)|} \tag{22}$$

The concept is also called usage method. Through the substitution of the line capacities by the sum of the absolute power flows the customers pay for the actual capacity and for additional reserves.

Zero-Counterflow-Method (ZCM)

In the Zero-Counterflow-Method (ZCM) customers whose power flow is in opposite direction of the net flow are not being charged. It is assumed that a net flow reduction is beneficial to system[17]

4.1.5 Relay Method

The name of this method relates to the general principle how transmission charges are calculated. The idea is to pass on transmission costs from node to node. This is considered a relay. For calculation purposes the power flow as well as the annual cost of each transmission facility (lines, transformer stations etc.) have to be known. Within this method two steps can be figured out:

1 Determination of cost rates for each facility

2 Calculation of transmission charges according to the 'relay principle'

ad 1) A transmission line causes annual costs due to operation, reinforcements and capital services. First, the idea is to define a cost rate per line. Two inputs are needed: the annual cost and the annual load duration curve. The curve determines how the peak power demand varies over time. Figure 9 shows an example of an annual load duration curve.

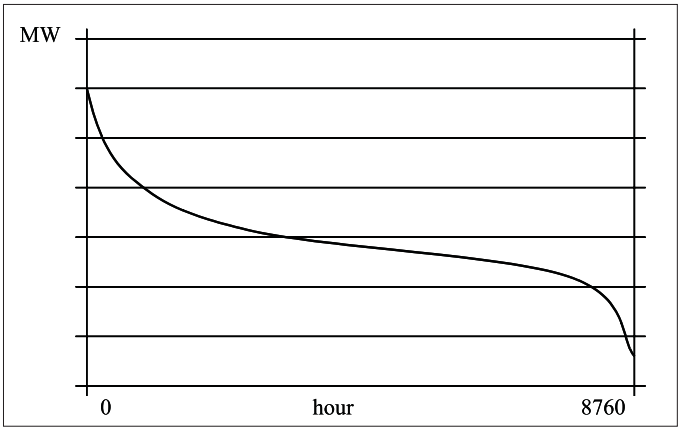

Figure 19: Example of an Annual Load Duration Curve

For determining cost rates two approaches are possible: a cost rate on basis of the peak load or a cost rate on basis of the transmitted energy. In [30] a cost rate based on the transmitted energy per line and year is proposed. The needed information can be derived from the annual load

[17] see [29] for a detailed description of the concept.

duration curve. The annually transmitted energy is calculated as product of an average power value and 8760 hours. The cost rate resp. utilization fee per line is then defined as:

$$n_{ji} = \frac{AC_i}{E_i} \tag{23}$$

with:

n_{ji}	utilization fee for line i
AC	annual cost line i
E	annually transmitted energy line i

After determining specific cost rates for each line, stage 2 can be carried.

ad 2) The main idea is to charge transmission fees in direction of the power flow from node to node. Whenever parallel flows occur average cost are calculated at the node where the flows rejoin. From every node out-bound flows take along charges, whereas costs are summed over the whole transmission distance. The method can be described as follows:[18][11]

- Find the starting node(s). At starting nodes their is no inbound load flow, although generators may inject into the node. Starting nodes are not charged transmission cost.
- The total cost for all nodes (except the starting nodes) are calculated according to equation (24). The algorithm "travels" from node to node. Precedent nodes pass on costs to their successors (equation (24)).

$$NG_i = \sum_{j \epsilon \alpha_j^{in}} P_{ji}(n_{ji} \cdot l_{ji} + ng_j) \tag{24}$$

with:

α_i^{in}	set of nodes, feeding energy directly into node i
P_{ij}	flow of active power from node i to node j
n_{ji}	specific transmission cost for line $i-j$
l_{ji}	line length $i-j$
ng_j	specific cost at node j

The specific cost at each node i is given by:

$$ng_i = \frac{NG_i}{\sum\limits_{j \epsilon \alpha_j^{in}} P_{ji}} \tag{25}$$

As the algorithm proceeds from node to node. The specific cost for precedent nodes serve as input for succeeding nodes.

[18]Here it is assumed, that the costs are assigned to the loads. Alternatively the generators may cover the costs.

- When all node specific costs are defined, the loads at the buses are charged according to equation (26), where P_{Li} represents the active power consumption of each load i.

$$NG_{Li} = ng_i \cdot P_{Li} \tag{26}$$

An illustrative example is to be found in [11]. As the method does not consider transmission resources scarcity, no incentives will be set for curing congestions. This drawback can be overcome by the introduction of flow depended cost functions. The specific line cost will increase as the actual flow approaches the capacity limitation.

The main advantage of this method results from the fact, that contractual agreements do not have to be known to the system operator. The assignment of the transmission cost is defined by the actual flow in the network.

4.1.6 Conclusions

In the above sections five embedded transmission pricing methods have been briefly described. The overall idea is to allocate the total system cost to the various users by determining their extend of use of the facilities. As the methods are only cost-based, no incentives are set for the reinforcement of the network. Nevertheless, the methods are widely used throughout the industry.

4.2 Incremental Pricing Methodologies

4.2.1 Introductory Remarks

Incremental pricing methodologies refer to the incremental pricing paradigm. In contrast to the above explained concepts not the embedded cost (the overall cost) are taken into account but the new resp. the additional transmission cost a transaction causes. In this respect two major viewpoints have to be differentiated.

1. considered period
2. type of cost

ad 1) The considered period is not specified in terms of a pre-defined time interval. The distinction refers to a common economical approach for cost evaluation. For short-run considerations the transmission capacity is fixed, where for long-run pricing schemes it is assumed that new capacities can be build. Thus, long-run incremental or marginal cost include (among others) the reinforcement and expansion cost as well as the operating cost. Short-run incremental or marginal cost only reflect the operating cost of the existing facilities.

ad 2) Within the paradigm two cost types can be distinguished: incremental cost and marginal cost. Both differ in the way they are evaluated. Marginal cost MC can be defined as the additional cost incurred by an additional transmission of one unit (e.g. one MWh),

whereas incremental cost IC are calculated by reviewing the transmission system costs with and without the entire transmission transaction.[23]

Equations (28) and (27) give the mathematical expressions. Both approaches will be explained in more detail in the sections 4.2.2 to 4.2.5.

$$MC_i = \frac{dC(P)}{dP_i} \tag{27}$$

$$IC_i = C(P + \triangle P_i) - C(P) \tag{28}$$

4.2.2 Short-Run Marginal Cost Pricing

In section 3.1.1 the pricing mechanism for perfectly competitive markets was briefly described. Schweppe was the first to transfer the marginal pricing scheme to electricity markets. The general idea 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 account of transmission constraints and electrical losses.

Mathematical Formulation of the Optimization Model

The optimization problem is formulated in equation 29.

$$maximise = \sum_k B(d_k) - \sum_j C(g_j) \tag{29}$$

subject to:

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

$$|z_i| \leq z_i^{max} \tag{b}$$

$$g_j \leq g_j^{max} \tag{c}$$

$$\sum_j g_j \leq g_{crit} \tag{d}$$

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}	amount of generation capacity at node j
z_i	flow along line i
z_i^{max}	maximum flow along line i

As seen in the first part of equation 29 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 29b gives the line flow constraints and equation 29c and d the total and the individual generation constraints. For the optimization problem the Lagrangean with the Langrangean multipliers μ_e, μ_i^{QS}, μ_j^{max} and γ can be formulated as follows:[19]

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

From the Langrangean the following expression for the nodal price can be derived:[20]

$$p_k = (\lambda + \gamma) \left[1 + \frac{\delta losses}{\delta d_k} \right] + \sum_i \mu_i^{QS} \frac{\delta z_i}{\delta d_k} \tag{30}$$

The first two Langragean multipliers λ and γ refer only to the generation side of the problem. For evaluating transmission pricing it is not necessary to deliver a detailed explanation.[21] The scarcity of transmission capacity is solely reflected by the multiplier μ_i^{QS}. General optimization theory states, that the Langrangean multipliers define, how the 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 shadow price. In the above context μ_i^{QS} reflects the market participants' valuation of

[19] For a detailed description on optimization methods see []:

[20] A stepwise description of the nodal price derivation can be found in [31]. In this paper only the implications for transmission pricing are relevant.

[21] see [31].

an 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 the affected bus.

Implications for Transmission Pricing

With no transmission constraints and losses neglected there will be one "system lambda" resp. one system price for the whole network (market).[32] As the "market" in this case does not consider the transmission resources scarce, no network revenues will be collected. The situation changes when at least one line is congested, resulting in different nodal prices as at least one μ_i^{QS} will be non-zero. The difference in nodal prices then gives the marginal network revenues[22] (equation (31)).

$$NR = \sum_{i \neq j} (\rho_i - \rho_j) \mid P_{ij} \mid \tag{31}$$

with:

ρ_i	price at node i
ρ_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[23]

For a simple discussion of the nodal pricing mechanism the network in figure 20 is considered.

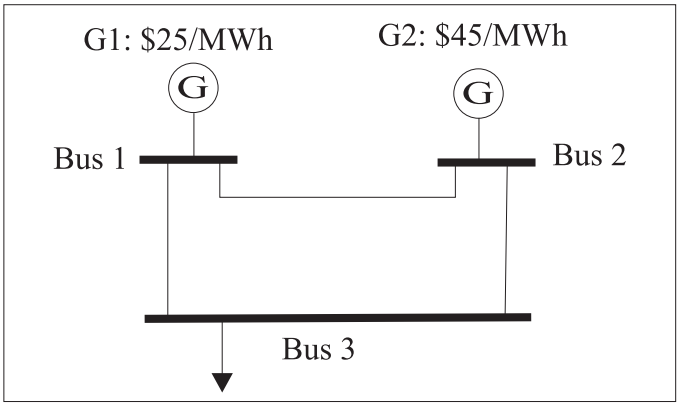

Figure 20: Example I: Nodal Pricing

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. Without constraint the spot pricing scheme reflects a least cost dispatch. As all nodal prices are $25/MWh no network revenues will be collected (see equation (31)).[24]

The situation shall 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 of 750 MW and generator 2 supplies the remaining output. This will result in an overall energy price of $30 per MWh. No network revenues will be collected.

Considering a last situation, the line from bus 1 to bus 2 shall be congested, where all lines shall 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. 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 can be collected according to equation (31).

The Cost Recovery Problem

As stated in paragraph *Implications for Transmission Pricing* no constraints in the network result in zero network revenues, which is not acceptable for a network owning or operating company. To overcome this problem a complementary charge can be defined (equation (32)):

$$CC_l = \max\{annual\ cost_l - NR_l\ , 0\} \tag{32}$$

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[32], although "the farther away the network is from the single node ideal situation, the larger is the network revenue"[32]. For the further appliance of spot pricing for transmission pricing the introduction of the complementary charge is mandatory. Where for the allocation of the complementary charge three methods have been proposed:[33]

[22] losses neglected

[23] For the following example network losses will be neglected

[24] It has to be mentioned, that, when the cost situation persists, generator 2 will in the long-run go out of business.

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 [33].

Conclusions

"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."[32] Marginally network revenues implicitly result from this spatial discrimination of spot prices[34], where in [32] 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.[33]

4.2.3 Long-Run Marginal Cost Pricing

In section 4.2.2 the short-run marginal pricing scheme was briefly described. It was stated, that for short-run considerations the transmission capacity is assumed to be fix. For long-run approaches this supposition is removed, the transmission capacity is allowed to change. This approach bases on the general economic theory on long-run marginal pricing. A comprehensive treatment of the theory can be found in [4]. Generally, for long-run considerations there are by definition no fixed cost. In the long-run all production factors are variable, where the optimization problem above all consists of finding the right plant size, i.e. the cost optimal transmission capacity. Briefly defined, LMC are the costs of increasing the production one unit, allowing changes in the overall system capacity, i.e. reinforcing or suspension (of parts) of the system. For the optimal capacity the LMC and the SMC are equal. Figure 21 gives a graphical problem description.

Case A depicts a situation, where the installed capacity is sufficient to meet the market demand. Here the SMC will equal the LMC. An expansion is not valuated. Thus, there is no incentive to reinforce the capacity. In case B the installed capacity is fully utilized. The price has to rise in order to limit market demand, subsequently a capacity charge is introduced. The capacity charge is to be seen as the customers valuation of a possible increase of transmission capacity. If the capacity charge plus the SMC is higher

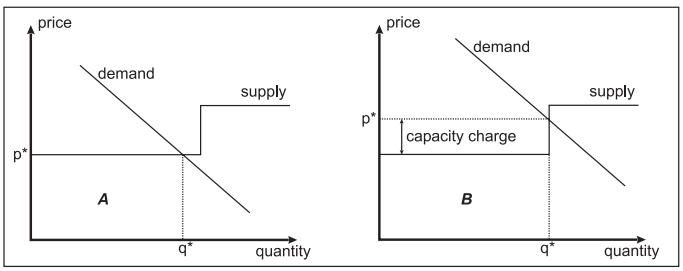

Figure 21: Short Run Marginal Cost and Capacity Charges [14]

then the LMC, it is in the long-run beneficial to increase the system capacity. In [14] it is stated that, if by definition the SMC include the capacity charge the following relation is applicable:

$$optimal\ capacity \Leftrightarrow SMC = LMC \tag{33}$$

In [23] the following approach for computing the marginal expansion (or reinforcement cost) is proposed: "Over a long time horizon of several years, all transmission expansion projects are identified and costed. This cost is then divided over the total power magnitude of all new planned transactions to calculate the marginal reinforcement cost."

The long-run marginal pricing scheme serves as approach for the evaluation of capacity reinforcements of the transmission system. Despite of the solid economical grounding of the theory, expansion plans are mostly driven by the system-operators' objectives to improve bulk system's reliability and to reduce short-term operating problems. In [35] a detailed analysis of Modeling Competition in Transmission Expansion is provided.

4.2.4 Short-Run Incremental Pricing

During the literature survey only one paper could be found, dealing roughly with incremental pricing schemes. In [23] a brief introduction is given, while most of the concept remains unexplained. This especially applies to the implementation problem. Generally, incremental pricing methodologies differ from marginal pricing schemes in terms of the cost definition. While under marginal pricing, the cost for a marginal increase of transmitted power is computed, within the incremental pricing methodology an "incremental" transaction is evaluated. In [23] it is stated, that regarding to SRIC all incremental (new) operating costs are assigned to a transmission transaction. Revenues collected compensate only for the short-run costs incurred by this specific transmission transaction. For estimating costs an optimal power flow model (OPF), determining all transmission and generation constraints as well as dynamic and static stability, can be used. Equation (28) gives a mathematical definition of incremental costs, although the definition could not be verified in the relevant literature.
Mainly there are two drawbacks of the incremental pricing method. Since more than one customer may be responsi-

ble for incremental costs an allocation method has to be outlined. Second, short-run transmission prices may be subject to high volatility.

It has to be mentioned, that from the outline given in [23] it could not be read, in which situation incremental pricing is explicitly favored over marginal pricing. Although the concept is theoretically defined, it lacks the clarity of the previously discussed methods.

4.2.5 Long-Run Incremental Pricing

The concerns of SRIC (see 4.2.4) also apply to the long-run marginal pricing scheme. There are no major modifications within the method, except that - with the introduction of the long-run view - also reinforcements of the network are considered. In [23] the reinforcement cost are determined as change in costs between long-term transaction plans and the current transaction cost.

4.3 Transmission Pricing Methods and Market Structures

In sections 4.1 and 4.2 the focus of the discussion was mainly on theoretical issues of transmission pricing methods. Information and implementation needs have been neglected. In [36] a systematization reaching from integrated to decentralized transmission pricing systems is proposed (see figure 22), which will be briefly explained below.

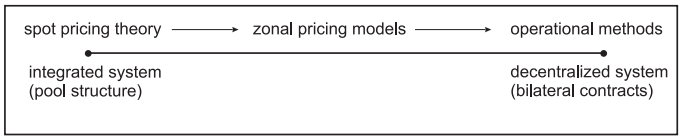

Figure 22: Transmission Pricing and Market Structures [36]

Figure 22 depicts the scope of organizational solutions for transmission pricing. On the one hand, absolutely centralized approaches are conceivable, where, on the other hand a completely decentralized system may be introduced. Which scheme is to be implemented depends - among other conditions - on the market structure. Sections 4.3.1 and 4.3.2 briefly discuss the two approaches at the outermost points of the spectrum. In the literature, the topic is rarely reflected. Only a few authors especially develop transmission pricing methods with respect to market structures (see [35] and [37]).

4.3.1 Centralized Transmission Pricing Approaches

For centralized structures spot pricing of energy is applicable. Spot prices reflect the system operation cost with respect to the demand at a certain node and a given instant of time. Thus, spot prices are to be seen as an integrated pricing approach consisting of several components referring to generation and transmission capacities' scarcity as well as losses in the system. The overall method to obtain spot prices is an optimization procedure of the social welfare (see 4.2.4)

For the implementation of this method data requirements are crucial. For both, demand and supply side, reliable functions have to be defined in order to model the generators' cost curves as well as the load elasticity. In a liberalized environment with a number of generating companies problems concerning the publishing of internal data are likely to occur. In order to optimize social welfare, generation has to be dispatched. The generation pattern may hereby favor certain generators, where others will be discriminated in their sales.[8] Another disadvantage draws from the integrated character of the spot price. 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.[38]

Thus, spot pricing as well as other marginal pricing methods are above all suitable for integrated market structures, such as pool markets.

4.3.2 Decentralized Transmission Pricing Approaches

For decentralized market structures focussing on bilateral contracts[25] operational approaches to transmission pricing are suggested. Market operating entities (ISOs or TransCos) are unlikely to know all settled contracts, although the network operator has to assign the grid costs to the various customers according to a reliable allocation principle. Operational approaches are based on the actual power-flow situation in the network. Physical Contracts are not considered as the power-flow[26] or only the transmitted energy[27] serve as calculation basis.

Alternatively in [36] a lump sum connection charge is proposed. Despite the practicability, introducing a "flat" charge for network access is considered to be economically inefficient since it causes a lack of incentives either to invest or deinvest in generation capacity. A modified system is used in Sweden, where connection charges are among other aspects[28] discriminated according to the geographical latitude of the specific customer. Installing generation facilities in high-demand areas is encouraged by lower tariffs, while loads in high-demand areas are forced to pay higher charges.

4.4 Conclusions

Sections 3 and 4 provided an introduction to transmission pricing in liberalized electricity markets. It was stated,

[25] Bilateral Contracts are also referred to Over The Counter Trade.

[26] See sections 4.1.4 and 4.1.5 for a brief description of the underlying methods

[27] See section 4.1.1

[28] Geographical discrimination is only one element of the pricing scheme. A comprehensive treatment of the system is to be found in [14].

that the pricing scheme of perfect competitive markets is not applicable to transmission markets, since they exhibit characteristics of natural monopolies. Thus, three pricing paradigms have been proposed: embedded or rolled-in transmission pricing, incremental pricing and a composite embedded/incremental approach. While the rolled-in paradigm has clear advantages in terms of practicability and cost recovery, it fails to set incentives for the reinforcement of the network. Incremental pricing methods are considered to have a profound economical basis, setting incentives for the installation of generation and transmission capacity, but in [32] it is shown, that they fail to recover the total system cost.

Alternatively to the cost-based paradigms auction-based methods for transmission pricing have been developed. Auction-based methods have not been reviewed within this report, since profound studies of bidding strategies and gaming theory would have been necessary. An introduction to the auctioning of transmission rights is to be found in [39].

For the implementation of the various methodologies market structures are setting a crucial framework. The scope reaches from completely centralized to decentralized approaches. Further effort has to be put into studying the connection between the organizational framework of markets and transmission pricing. It is agreed, that there is no overall solution for transmission pricing applicable to all conceivable market structures.

5 Summary

The report gave an introduction to the basic principles of electricity markets especially focussing on issues concerning transmission markets. While within energy markets competition may be introduced, the transmission grid remains a natural monopoly under regulation. As the pricing principles valid in competitive markets can not be applied to transmission markets, it is still discussed which pricing scheme should be implemented in order to ensure[40]:

1. economic efficiency
2. non-discrimination
3. transparency
4. cost recovery
5. congestion avoidance

It is agreed, that marginal pricing schemes promote economic efficiency by setting incentives a) for the momentary use of existing transmission facilities and b) for the reinforcement of the network. Despite of its advantages the marginal pricing scheme is likely to fail in recovering the total system costs and - as transmission revenues increase the further the system is away from an optimal state - the ISO may also have an incentive to withhold transmission capacity. In contrast to marginal pricing embedded methods recover total system costs. They are widely used throughout the industry, but fail to set incentives for either the efficient use of the system and for further expansion. Thus, it is obvious that embedded methods are no applicable to comply with point 5 'congestion avoidance' as they give no short-run price signals for the efficient despatch and in the long-run for the siting of generation capacity. For congestion management one implication from transport economics is crucial: "Demand for transport is derived from supply and demand in product markets."[41] As the 'product' in electricity markets is electrical energy in [41] it is emphasized, that only composite pricing mechanisms taking into account the generation configuration as well as the specifications of the transmission network will promote efficiently working markets. Congestion avoidance or management has not been studied within this report, although it plays an essential role in market operation and optimization. Several congestion management methods have been proposed. A structured overview with numeric examples is to be found in [42], where it is outlined, that "considerable research" is going on this field. The objective in transmission pricing as well as in congestion management is to find methods which promote the efficient use of the actual system while ensuring the stability of the system in the long-run. As reflected in the recent literature there will be no generally applicable method, but for every national resp. international market manifold studies have to be carried out in order to make competition work.

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