OPENING OF THE EUROPEAN MARKET FOR ELECTRICITY

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FOR ELECTRICITY

P. Van Roy
R. Belmans
G. Pepermans
S. Proost
B. Willems
L. Conings

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University of Leuven Energy Institute

C/o Applied Mechanics and Energy Conversion
B-3001 Leuven (Heverlee)
Belgium

Preface

The K.U.Leuven Energy Institute started its research activities for the K.U.Leuven Energy Foundation Industry-University in 1997. For its medium-term generic research, it concentrates on two major subjects: the Kyoto protocol for greenhouse-gas reduction and its consequences and the effects of the liberalisation of the European market for electricity. The first report, formally published on May 31, 1999, dealt with the Kyoto protocol. This second report deals with the liberalisation of the electricity market.

After a year-long process of negotiations between the European Member States, the Directive 96/92/EC on common rules of the internal market in electricity was adopted on December 19, 1996. It entered into force two months later, and gave Member States two years to comply.

Although there was a delay in some Member States, all have now implemented the Directive. However, strong harmonisation efforts are still needed, particularly on cross-border transmission and congestion management issues, before the 15 separate countries form one European wide internal market.

Belgium is located at the very heart of the European electricity network. This also means the Belgian network is particularly influenced and on occasion even threatened by the growing number of, sometimes unannounced, international transactions. In order to ensure a safe and reliable system operation, and in order to prevent a system-wide black-out, it is essential that proper agreements are made between the European system operators and regulators. In this process, Belgium could play a central role.

The liberalisation in Belgium is moving ahead, although a lot of decisions are still awaiting the advice of the regulator. Some major industrial companies have switched producers, and for the not-yet eligible SME and households, tariffs drops are promised.

In this context, it is interesting to provide an overview of both European and local developments. The first part of the report deals with the European background, describing the Directive and the harmonisation efforts, as well as the state of the implementation in the most relevant and neighbouring European countries. The report also describes the fundamentals of trading and price setting.

The second part of the report focuses on Belgium. Starting from the pre-liberalisation situation, the present state of the implementation is described, with some attention to the various calendars that have been proposed for opening up the market.

The report continues with the results of two studies that have been performed by the K.U.Leuven research groups that make up the Energy Institute. The first deals with the issue of stranded costs, and more specifically stranded costs in Belgium. The second deals with transmission pricing. It presents general pricing criteria, applied to electricity transmission, and the modified postage stamp transmission tariff for Belgium, as proposed by the K.U.Leuven.

For the moment, distribution is only touched upon slightly. In future, the impact of the liberalisation on a distribution level will be studied in more detail.

The report was ready in draft form in December 1999, and presented to the members of the Energy Foundation. We gratefully acknowledge their comments, and have taken them into account for the present version.

June 28, 2000

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European Directive

Introduction

Directive 96/92/EC concerning common rules of the internal market in electricity was adopted by the Council of Ministers on December 19, 1996. It entered into force two months later on February 19, 1997.

Basically, the Directive provides for:

- free competition for generation, with either an authorisation or a tendering procedure for building new generation capacity;
- a market on the consumers' side, that is open to a minimum degree; countries may choose to open their market more than this minimum degree;
- free access to the transmission network, with Third Party Access, or through a Single Buyer, or a mix of these;
- unbundling of accounts between generation, transmission, distribution and other non-electric activities, if these are present within one company; the accounts must be open to the competent authorities;
- public service obligations that may relate to security, including security of supply, regularity, quality and price of supplies and environmental protection.

Member States had two years to bring into force the laws, regulations and administrative provisions necessary to comply with this Directive.

Generation

For the construction of new generating capacity, Member States may choose between authorisation or tendering, or a mixture of both. Whatever procedure chosen, it must be conducted in accordance with objective, transparent and non-discriminatory criteria.

Transmission

Member States designate, or require undertakings owning transmission systems to designate, a system operator responsible for operating, ensuring the maintenance and if necessary developing the transmission system in a given area and its interconnections with other systems in order to guarantee security of supply.

Access to the network

Member States can choose between *negotiated or regulated third party access* (n-TPA and r-TPA) or the *single buyer procedure* (SB) when organising the access to the transmission and the distribution network. Whatever option chosen, both sets of procedure shall operate in accordance with objective, transparent and non-discriminatory criteria.

Negotiated TPA is characterised by the fact that producers and consumers of electricity can contract supplies directly with each other, but that they have to negotiate access to the network with its operator. Such negotiations deal with transport tariffs and other conditions.

In case of *regulated TPA*, producers and consumers also contract directly with each other for supply. The price for the use of the transmission and distribution systems can, however, not be negotiated. The eligible consumers have a right of access on the basis of published tariffs. In the case of r-TPA, Member States shall also designate a competent body to settle disputes.

The *single buyer* is defined in the Directive as a legal person responsible for the unified management of the transmission system and/or for centralised electricity purchasing and selling.

Market opening

The Directive provides for a gradual market opening in three steps: 1st step on February 19, 1999, 2nd step on February 19, 2000, and 3rd step on February 19, 2003. The minimum market opening corresponding to the 1st step is calculated as the share of the overall consumption in Europe consumed by final consumers with an annual consumption exceeding 40 GWh per year. This implies that about 26.48% of each national market is opening for competition. In the 2nd step, the threshold is reduced to 20 GWh per year, increasing the minimum market opening to about 28%. In the 3rd step the threshold is further reduced to 9 GWh per year, equalling a market opening of about 33%.

Harmonisation Process

The EU recognises that the implementation of the Directive in each Member State is only the first step. For the completion of an internal energy market, trade between the Member States has to be facilitated. Major existing or expected obstacles were outlined in the Second report to the council and the European parliament on the harmonisation requirements, dating from April 1999.

Obstacles for cross-border trade of electricity

Main obstacles for cross-border trade of electricity are:

- the definition, calculation and maximisation of available interconnector capacity (ATC);
- the management of insufficient ATC;
- the adoption of a harmonised cross-border tarification, without pancaking and based on physical flows.

Regulation of the electricity network at European level

The existence of a European liberalised electricity market requires some kind of regulation and a tarification system, supervised on the national as well as on the European level, in order to avoid discrimination and excessive pricing and to support reinforcements in the network.

Ensuring a level playing field in the European electricity market.

There are three specific areas that could lead to possible distortions of competition within the internal market as a result of diverging legal standards, mainly affecting the cost of electricity generation:

- Environmental standards, mainly those focussing on air pollution, influence the choice of generation technology and therefore the cost of electricity generation.
- Diverging standards for nuclear decommissioning and different regulatory approaches to the management of decommissioning funds may cause market distortions.
- Indirect and direct taxation.

ERF Meeting in Florence

It had already been agreed that each TSO's network costs would mainly be recovered through the G and L charges. It is now also accepted that cross-border trade (CBT) may lead to extra costs. Inter TSO payments will be used to compensate for the cost of physical transit or loop flows. An initial system for one year should start on October 1, 2000, while a refinement process is going on.

On the issue of congestion management, more progress is expected at the next ERF meeting.

Implementation in Europe

Most attention is given to Germany, The Netherlands, France, the UK and the Scandinavian countries.

Germany

Germany is going through a process of price war, with declining profits, combined with mergers and acquisitions. VEBA and VIAG, the mother-holdings of PreussenElektra and Bayernwerk, are merging into EON. RWE and VEW are merging as well. Both the German and the European anti-trust authorities will accept these mergers only under some strict conditions. RWE, PreussenElektra and Bayernwerk have to withdraw from the suffering VEAG in the former East-Germany. The 0.25 pf/kWh transit fee between the North and South trade zones within Germany, as planned in the new Verbändevereinbarung, has to be abolished.

The Netherlands

The situation in The Netherlands is described in some detail, as an example of a country with clear legislation and a fully active regulator. Noticeable is the fact that most of the relatively small Dutch utilities have been taken over by or have merged with foreign utilities. Furthermore, The Netherlands is importing as much power as is permitted by the limited import capacity. Extension of the interconnector capacity through upgrading of the lines in Germany is underway, as are discussions for a new allocation mechanism for the limited capacity.

France

The French electricity act was finally accepted in February 2000. The degree of opening will be the minimum required.

UK

In the UK and Wales, the reform of the pool has led to the NETA, the New Electricity Trade Arrangements, to be started in Autumn 2000.

Trading and Price Setting

Physical Market

As a first approximation the market for electricity is not fundamentally different from any other market. The price and the quantity of electricity produced and consumed are determined by the willingness to pay of the consumers and the costs of the generators.

In practice, two technical problems prevent electricity to be traded as any other good. The first problem, the *balancing problem,* is that the demand and the supply of electricity have to be equal each second. The market can not respond that fast to changing electricity flows. The second problem, the *constraints problem,* is that grid constraints can reduce the possible trades.

The System Operator solves these problems by splitting up the market in the *energy market* and the *regulating market*. He transfers both problems to the regulating market. The System Operators will contract the generators and the consumers, who are able to change their quantities relatively fast and in a controllable way, to provide regulating power.

In the energy market generators and consumers are free to negotiate transactions up to one day before actual delivery. These transactions are organised with bilateral contracts between the generator and the consumer or with pool contracts concluded on an anonymous market for electricity (the pool).

Financial Markets

A cash contract is an agreement to trade a fixed quantity of electricity at a fixed date in the future at the then prevailing spot price. It ensures the exchange of electricity. Since this future spot price is unpredictable, the uncertainty about the cash flow of this cash contract is large. Financial instruments such as forward contracts and futures contracts can be used to remove this price uncertainty.

In a forward contract players agree upon a fixed price for the future trade. Hence, the cash flow of this contract is fixed in advance. The forward contract thus provides two services: the exchange of electricity and an insurance against price changes.

We can separate these two services: a cash contract ensures the exchange of electricity, and a futures contract provides the insurance against future price deviations.

Implementation in Belgium

Pre-liberalisation Situation

The existing power system in Belgium is dominated by the private company Electrabel. Electrabel controls 88% of production and 80% of distribution, through the mixed intermunicipalities. Electrabel also has the major share in CPTE, the Company for the Co-ordination of Production and Transmission of Electricity.

Transmission

The 380, 220 and 150 kV transmission network is owned by the CPTE. The CPTE controls the grid from their national dispatching centre in Linkebeek. The technical competence of the CPTE as network operator is not disputed.

Distribution

Municipalities have the legal monopoly on local distribution. Most of them work together with Electrabel in the so-called mixed intermunicipals, resulting in Electrabel participating in 80% of the distribution. The other municipalities control the distribution themselves in the so-called pure intermunicipals.

Consumers

Consumers directly connected to the high voltage grid and with an annual use of more than 100 GWh, make up 33% in 65 sites.

Tariffs

There is continuing debate about the reasons for the high electricity tariffs in Belgium. A group of experts quotes the depreciation rate of the nuclear power plants as the main reason. Given the fact these power plants are now depreciated, they feel significant tariff reductions of 15 to 20% are possible.

Last year already, in September 1999, the CCEG decided on important tariff reductions. In April 2000, the federal government decided there should be an average tariff reduction of 15 to 20% for households and SME in the next two years.

In May 2000, the results of the tariff comparison study ordered by the CCEG from Wefa were made public. It compares tariffs with France, The Netherlands, Germany and the UK. Only the largest industrial consumers, the largest residential consumers and consumers benefiting from the social tariff have lower prices than in neighbouring countries. Others pay up to 19% more. On top of this, the Belgian VAT is higher than in the neighbouring countries.

Other actors

CCEG

The electricity and gas monitoring committee (ControleComité voor de Elektriciteit en het Gas, CCEG) has been the regulator for 40 years. This autonomous, public utility organisation is composed of controlling instances and controlled parties. The CCEG is responsible for ensuring that tariffs and economical and technical developments comply with general energy policy. They set plant depreciation rates, decide the contribution the sector makes to sustainable energy programmes and are responsible for a fund set aside for decommissioning nuclear power plants. In future, their competence will be limited to the non-eligible market.

State of the Implementation

The federal law on implementing the Directive has been accepted the 29th of April, 1999. Most of the royal decrees for the detailed implementation and the nomination of the system operator are awaiting the advice of the regulator, who was nominated the 3rd of December, 1999.

Regulator

The General board consists of representatives of all interested parties, i.e. the federal and regional governments, trade unions, employers, producers, distributors and consumers.

The Executive Committee consists of a chairman and 5 other members, responsible for market contention, technical operation of the electricity and gas market, price control of the electricity and gas market, and administrative matters. Members are appointed for 6 years, except for two of the initial members, who are appointed for three years.

Production

Every three years the Regulator presents an indicative program for generating facilities covering a period of ten years. Belgium opts for the authorisation procedure (i.e. licenses) for the construction of new generation plants. The criteria for this authorisation will be periodically adapted, taking into account the indicative generation program.

Transmission

The owner(s) of the transmission grid appoint, after approval by the government, a Transmission System Operator (TSO) for a renewable period of 20 years. The TSO has to be independent. The TSO has not yet been appointed, and possibly the acting system operator CPTE will be appointed as temporary system operator, for a period of two years, before a final decision is taken by the government.

Grid access

Grid access is based on regulated Third Party Access (TPA), except for transits and large volumes that have a negotiated TPA. CPTE has published temporary transmission tariffs as acting system operator.

Opening of the market

Consumers connected to the transmission-grid.

Different proposals for a faster opening than the minimum required by the Directive exist. In most proposals, consumers of more than 20 GWh/year would be free from July 2000 on, consumers of more than 10 GWh from 2002 and consumers of more than 1 GWh from 2003.

Consumers connected to the distribution grid.

The distribution companies are eligible for the consumption of the eligible end-users of their distribution-grid, the responsibility to free the end-users of the distribution companies lying with the regional authorities.

Flemish draft decree

The Flemish government agreed on a draft decree. Major characteristics are:

- the immediate opening of the market for all consumers of more than 20 GWh/year;
- a progressive but fast lowering of this limit in the following years;
- a forced unbundling of distribution companies in a distribution system operator and a supply company;
- a system of green certificates from 2001 on, aiming at 3% of supply in 2004[1]. If a supply company does not achieve the 3% limit, they will be heavily penalised.

[1] The decree imposes the production of electricity from renewable sources to take place within Flanders. The EU would accept a minimum percentage of green electricity to be produced in each country separately, despite the fundamental rules of the open market.

Stranded Costs in Belgium

Stranded costs have to do with the transition from a regulated to a more competitive market.

Definition of Stranded Costs

A distinction is made between strandable costs and stranded costs. In this chapter, strandable costs are fixed or sunk costs imposed by the regulator. Fixed and sunk costs are costs that in the short term do not vary with the level of production and can therefore not be avoided.

These costs become stranded costs when they cannot be recovered when the market is opened up for competition. The following table illustrates the difference between the concepts of strandable and stranded costs.

		SUNK COSTS IMPOSED BY THE REGULATOR?	
		Yes ↓ ***Strandable***	***No*** ↓ ***Not strandable***
RECOVERABLE VIA THE MARKET?	***Full recovery***	Not stranded	Not stranded
	Partial recovery	Non-recoverable part is stranded	Not stranded
	No	Stranded	Not stranded

Table 1: **The definition of strandable and stranded costs.**

Are Allowances for Recovery of Stranded Costs Necessary?

When one is concerned about economic efficiency, allowing for stranded costs recovery is not necessary. On the other hand, if financial support for stranded cost recovery is given, then it should be organised in a competitively neutral way and with a minimum of welfare loss[2]. Moreover, there is an upper limit to the size of the support, i.e. it may not be larger than the strandable costs.

Of course, if there is no recovery of stranded costs, the firm will make a loss on the home market but this does not result in inefficiencies.

Effect of Alternative Mechanisms to Recover Stranded Costs

A simple economic model was used to test what could be the welfare effects of alternative mechanisms to recover stranded costs. These exercises can illustrate orders of magnitude. In this exercise, two markets are distinguished: the open market of big industrial consumers (35% of total) and the market of smaller consumers that

[2] From the point of view of efficiency, any distortion (e.g. a tax) introduced to implement the recovery mechanism will make society worse off compared to the situation where no recovery is allowed, since in the latter case Pareto-efficiency is reached anyway.

are supplied via the distribution companies. It has been assumed that the profit margins in the distribution sector remain constant at their 1996 level.

The effect on welfare of opening the electricity market for the big industrial consumers depends on the supply price of the foreign producers and on the ease with which the big consumers switch to another supplier.

When the supply price of the foreign producer is only slightly lower than the marginal cost of the home producer, opening the market could give higher profits for the home firm if he succeeds in charging a higher price in his market segment.

If the supply price of the foreign producer is much lower than the marginal cost of the home producer, welfare gains through import substitution are possible. This gives net benefits for the industrial consumers and the profit of the home producer decreases. This total profit will not be strongly affected by these imports, because the largest share of his profits comes from the small consumers market. In most sensitivity studies, the opening of the market leads to lower profits, but the profits decrease remains limited, so that there are no stranded costs.

Transmission Pricing for Belgium

General Pricing Criteria

In general, an ideal pricing mechanism should satisfy four criteria.

Provide incentives to the market participants

In general, prices are the instrument used in the economy by market participants to communicate with each other. Prices convey important economic information. Price changes should give incentives to consumers or producers to change their behaviour, i.e. to increase or decrease their demand or supply.

Applied to the electricity transmission market, economic efficiency implies that the transmission prices should provide the electricity consumers and suppliers with the correct economic incentives in at least three ways:

- encourage an efficient location of new generation capacity and new consumers;
- encourage an efficient use of the existing network;
- encourage efficient investments in network expansion and maintenance.

Prices must allow system operators to cover their costs

This may seem to be an obvious criterion. If, in any kind of market, a provider is not able to recover his costs at the prevailing market price, then he has to adapt output and/or costs. If this is not possible, there is no reason to stay in the market.

It can be shown that in the case of a *natural monopoly* the ‘cost recovery’ criterion is incompatible with the first criterion. Marginal cost pricing implies that the price is below the average cost, i.e. the company makes a loss. Of course, this is not a viable situation in the long run.

Prices should be non-discriminating

Prices are non-discriminating if identical consumers, buying a good at the same place and the same time, pay the same price or in general receive the same treatment. This criterion does not imply that the market price must remain unchanged over a period of time, or that there can be no place dependency.

Prices should be transparent

It is desirable that the pricing mechanism applied by the regulator is transparent in the sense that all the parties involved (consumers and producers) understand the price structure and can take the structure into account in their decisions.

Matching Efficiency and Cost Recovery

In general, these four criteria are satisfied if the market structure is perfectly competitive, i.e. if no individual consumer or supplier of transmission facilities can influence the market outcome through his own behaviour. However, it has been mentioned before that this condition is not satisfied in the transmission of electricity, being a natural monopoly.

In that case, there is a role for a benevolent regulator wishing to maximise economic welfare. If the regulator imposes a price equal to the marginal cost, the resulting outcome will be the same as in the perfect competition case, satisfying the allocative efficiency criterion.

However, implementing marginal cost pricing results in a loss for the monopolist and in the long run, there is no reason why the monopolist would stay in the market.

One solution might be to subsidise the monopolist's financial loss. Of course, this subsidy would have to be paid by the taxpayers and it is known from taxation literature that this creates distortions in the economy and thus lowers economic welfare. The trade-off between allocative efficiency and cost recovery has led to alternative pricing rules satisfying a revenue requirement for the monopolist but having prices closer to marginal cost than simple average cost pricing. Examples are *Ramsey pricing, two-part tariffs* and *peak-load pricing*.

Typical Issues for Electricity Transmission Pricing

Electricity must not only be generated, but it must also be delivered at a given node, accounting for transmission constraints (congestion) and transmission losses. Both elements should be reflected in the transmission prices. Some other elements that affect transmission prices are ancillary services and market power at the supply side.

Implementation for Belgium

Given the characteristics of the firmly linked Belgian grid, we propose a pricing scheme starting from a postage stamp method, with improvements to give the required incentives. The postage stamp is applicable to both producers and consumers.

Postage stamp for cost coverage and non-discrimination

The annual postage stamp tariff should allow the transmission company to recover its costs for running the system while treating all grid customers, using the grid at the same time and place, in a similar way. Starting from the existing situation, these costs should include all functions the system operator has to provide. Next to the actual costs, a fair return on investments should be part of the basic postage stamp rate.

Individual cost component

Costs that can clearly be identified as being due to a particular customer, such as (new) connection, metering and billing costs, are charged to this customer.

Demand component

Fixed costs, i.e. maintenance, general improvement, increasing reliability and keeping the system in line with the present state of technology, black-start capability and personnel cost plus the fair return on investment, are charged per kVA peak demand.

Energy component

Variable costs, i.e. the costs of losses, reserve and reactive power, are charged per kWh.

The tariff as defined until this stage, does not give any incentive towards efficient use of the grid, siting of new generation or demand, congestion avoidance or future investments, except for a voltage level dependence and a penalty for reactive power outlyers.

Incentive for dispatching generation and for the siting of new generation or demand

The TSO should provide incentives for both dispatch of generation and for future investments in generation and new demand nodes to be located at those places where they best support the overall system regarding congestion, losses (including those under peak conditions), voltage stability, reliability and safety. A certain generator may be at a point in the grid where its presence is essential to maintain voltage stability. Therefore, the value of that generator should be higher than that of a generator at a very stable node. This differentiation would be expressed in the Grid Quality Charge (GQC).

Transparency

Clearly all tariffs should be published for transparency and in order to allow the clients to take the necessary actions to use the system in an optimal and efficient way. This includes the node dependent Grid Quality Charge.

Incentive for efficient operation and network investment

Maintenance and operation

The system operator should be rewarded or penalised for the quality of his operation, including maintenance, switching of lines, voltage regulation, ... The quality could be compared with neighbouring systems.

Investment and network expansion

By investing, the network operator can improve the quality and reliability of the power system, thereby reducing penalties. Furthermore, included in the total cost leading to the basic postage stamp rate, is a fair return on investment and capital cost.

However, all this may lead to over-investment and a gold plated network. Therefore, an incentive for overall cost reduction is needed.

Incentive for cost reduction

This is a fundamental problem in any monopoly system. The best solution is a system of benchmarking, through comparison with similar power systems in other countries.

In function of the quality of the system operation and the cost reduction, compared to neighbouring countries, the basic postage stamp rate is modified.

International Context

Import, export and transit

For transactions between producer and consumer within one control area, the relative position of both is irrelevant. What matters is the position of generator and load, and their local impact on the grid. The generator would be charged G and the load L. The relative importance of these two components needs to be harmonised on a European level.

For international transmission, there is a clear physical flow, resulting from the net generation-demand mismatch in the different countries. This implies that, in our view, some kind of transmission element in the tariff is justified.

According to the most recent evolution on a European level, countries would only receive a compensation for cross-border exchanges in the case of transit, and not for import or export separately. This may lead to inequalities, depending on the degree of import and export.

A further and more detailed study of the impact of the latest ETSO and ERF proposals is needed. In our proposal, import and export are treated similarly as local generation and demand. Each TSO only charges for costs in his network, avoiding pancaking.

Import should be treated similarly as locally generated power, with the border node(s) as generation node.

The Grid Quality Charge for G_{import} is calculated for the border node(s), taking due account of the benefits of opposing flows.

An export node should be treated as a load, but the transmission costs are charged to the generator in Belgium.

The treatment of import and export in this way makes it transparent for the TSO: whether the power is produced within its control area or not is of no importance.

The last point is transit power. This should be treated as in the import/export discussion above. The same postage stamp tariff with all surpluses has to be used, charged to the TSO's of the involved neighbouring areas. Reactive power is one of the major concerns here.

Uncontracted power flows

Until now, contracted power flows were discussed. The real problem is caused by so-called loop flows.

Basically, an improved international co-operation between the system operators should prevent the existence of unannounced loop flows. If this is impossible and loop-flows cause severe problems with extra costs, these have to be recovered from the neighbouring system operators who were not willing to divulge the relevant information.

The need for abandoning the contract path fiction and using measured flows instead is recognised in the latest ERF meetings in Florence.

List of Abbreviations and Acronyms

AC	Average Cost
AFC	Average Fixed Cost
APX	Amsterdam Power Exchange
ARE	“Arbeitsgemeinschaft regionaler Energieversorgungsunternehmen”, representing the regional companies in Germany, part of VDEW
ATC	Available Transmission Capacity
ATSOI	Association of Transmission System Operators in Ireland
AVC	Average Variable Cost
BATNEEC	Best Available Technology, Not Entailing Excessive Cost
BCEO	“BeheersComité der ElektriciteitsOndernemingen”, co-operation of Electrabel and SPE in Belgium
BDI	“Bundesverband der Deutschen Industrie”, representing the industrial consumers in Germany
BEWAG	German power utility, see page 21
CCEG	“ControleComité voor de Elektriciteit en het Gas”, regulator for the non-eligible electricity and gas market in Belgium
CFD	Contract for Difference
CHP	Combined Heat and Power plant
COM	European Commission
CP	Capacity Payment, in UK
CPTE	Company for the Co-ordination of Production and Transmission of Electricity, TSO in Belgium
CREG	“Commisie voor de Regulering van Elektriciteit en Gas”, new regulator for the eligible electricity and gas market in Belgium
DTe	“Dienst Uitvoering en Toezicht Elektriciteitswet”, Dutch regulator
DVG	“Deutsche Verbundgesellschaft”, representing the eight Verbund generating companies in Germany, part of VDEW
E	Entrant, new company in the market
EC	European Community; since 1993: European Union or EU
EC	Energy Component, in Belgian transmission tariff proposal
EdF	“Electricité de France”, French utility
EEX	European Energy Exchange, Frankfurt
EL-EX	Finnish Electricity Exchange
EnBW	German power utility, see page 21
ENEL	“Energia elettrica”, Italian power utility
EPON	Dutch utility

EPZ	Dutch utility
ERF	European Regulatory Forum
ETSO	European Transmission System Operators, an association of ATSOI, UKTSOA, NORDEL and UCTE. Members are the 15 countries of the EU plus Norway and Switzerland.
EU	European Union; before 1993: European Community or EC
EZH	"Elektriciteitsbedrijf Zuid-Holland", Dutch utility
F	Fixed cost
FACTS	Flexible Alternating Current Transmission Systems
G	Generator connection component of transmission tariff
GATT	General Agreement on Tariffs and Trade
GOAL	Generating Ordering and Loading, in UK
GQC	Grid Quality Charge
γ_{VL}	voltage level dependent multiplication factor, in Belgian transmission tariff proposal
HEW	German power utility, see page 21
I	Incumbent, existing company in newly opened market
ICC	Individual Cost Component, in Belgian transmission tariff proposal
IEM	Internal Electricity Market
ind	industrial
IPPC	Integrated Pollution Prevention and Control
k	country participation factor in transmission tariff
L	Load connection component of transmission tariff
LCPD	EU Directive on controlling emissions from Large Combustion Plants
LPX	Leipzig Power Exchange
LUP	"Landelijk Uniform Producenten transmissietarief", transmission tariff for generators in The Netherlands
MC	Marginal Cost
Mln	Million
MWt	MW-thermal: thermal capacity of a power plant as opposed to electric capacity
NGC	National Grid Company, TSO in UK/Wales
NLG	Dutch guilders
NORDEL	Nordic Transmission System Operators: Denmark, Finland, Iceland, Norway and Sweden
NTC	Net Transfer Capacity, i.e. TTC-TRM
n-TPA	negotiated TPA
NVE	Norwegian Water Resources and Energy Directorate , regulator in Norway

Offer	Office for Electricity Regulation, UK
Ofgas	Office for Gas Regulation, UK
Ofgem	Office for Gas and Electricity Market, UK
p	price, also P
PCM	Price Control Mechanism, in UK
PD	Peak Demand
PPP	Pool Purchase Price, in UK
PSA	Pooling and Settlement Agreement, in UK
PSO	Public Service Obligations
PSP	Pool Selling Price, in UK
q	demand, also Q
REC	Regional Electricity Company, in UK
res	residential
RETA	Reform of Electricity Trading Arrangements, in UK
RPI	Retail Price Index
r-TPA	regulated TPA
RWE	German power utility, see page 21
SB	Single Buyer
SEP	“Samenwerkende Elektriciteitsproducenten”, co-operation between UNA, EPZ, EPON and EZH, The Netherlands
SME	Small and Medium size Entreprises
SMP	System Marginal Price, in UK
SPE	“Samenwerkende vennootschap voor de Productie van Elektriciteit”, public utility in Belgium
STAG	Steam And Gas power plant
T	Transit component of transmission tariff
TFC	Total Fixed Cost, in Belgian transmission tariff proposal
TPA	Third Party Access
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TT	Transmission Tariff
TTC	Total Transfer Capacity, also ATC
TVC	Total Variable Cost, in Belgian transmission tariff proposal
UCTE	Union for the Coordination of Transmission of Electricity, former UCPTE
UKTSOA	United Kingdom TSO Association
UNA	Dutch utility

VAR	reactive power
VAT	Value Added Tax
VBO	"Verbond der Belgische Ondernemingen", represents Belgian entreprises
VC	Variable Cost
VDEW	"Vereinigung Deutscher Elektrizitätswerke", representing the generating utilities in Germany
VEAG	German power utility, see page 21
VEW	German power utility, see page 21
VIK	"Vereinigung der Industriellen Energie- und Kraftwirtschaft", representing the autogenerators in Germany
VKU	"Verbund kommunaler Unternehmen", representing the municipal companies in Germany, part of VDEW
WTP	Willingness To Pay
X	Efficiency incentive for TSO, in RPI-X formula

Electrical Units

A	Ampere, unit of current
V	Volt, unit of voltage
W	Watt, unit of (active) power
VA	Volt-Ampere, unit of apparent power
VAr	Volt-Ampere-reactif, unit of reactive power
Wh	Watt-hour, unit of (electrical) energy, 1 W during 1 hour
VArh	Volt-Ampere-reactif-hour, unit of reactive power consumption

Practical units are multiples of these:

k: 10^3 M: 10^6 G: 10^9 T: 10^{12}

as in kV, MW, kWh, MWh, GWh, TWh, …

Remarks

- Numbers are given as "1 000 000.00", i.e. "." to indicate decimals and space to indicate thousands and millions.
- Transmission line or interconnection line capacity is normally given in MVA. However, some sources give capacity in MW.
- Throughout the report, the term "customer" is used as customer of the transmission network, i.e. producers and consumers, and any other market player when dealing with the transmission system operator, such as traders and suppliers. The term consumer is reserved for a market player consuming electricity.

I. INTRODUCTION AND OBJECTIVES

In December 1996, the European Council of Ministers adopted the European Directive concerning common rules for the internal market for electricity. The transformation of the European electric industry, from having been regulated, towards a market-based philosophy, leads to a major revolution regarding the way demand and supply of electricity are met. Indeed, a major characteristic of electric energy – distinguishing it from other commodities – is, that at any moment in time supply must balance demand (including system losses), without intermediate storage facilities.

In the regulated, often centralised system, the technical requirements for matching supply and demand were considered first; the cost and the sales price were "merely" derivatives. Generally speaking, this resulted in a high degree of reliability of supply, but at fairly high prices. In a liberalised market, matters are the other way around. The driving force is the market, whereby economic transactions dominate the scene. The electro-technical aspects (related to the reliability of supply) are now de facto considered as the derivatives. As a matter of fact, the electric power system is challenged considerably to meet the requirements imposed by the market forces.

It is of utmost importance for all the actors involved (on the supply as well as the demand side) to understand the consequences and implications of this dramatic change. In order to have a clear grasp of the overall issue, it is mandatory to confront the electro-technical boundary conditions with the market desires. On the other hand, the thrust created by the market may induce new ideas concerning the structure and the way of operating the electric grid.

This report aims at presenting an overview on developments in Europe and Belgium. After this introduction, the report focuses on the institutional developments as a consequence of the European Directive and the harmonisation requirements (Section II). Consecutively, the implementation in Europe, focussing on the most relevant countries, is discussed (Section III). Trading and price setting in the liberalised market are studied in Section IV.

The remaining three sections focus on Belgium: the implementation in Belgium in Section V, the problem of stranded costs in Section VI and finally transmission pricing in Section VII. The implementation of a transmission tariff for Belgium - including import, export and transit – is based on our own proposal, in a study for the Federal ministry of Economy, made in the first half of 1999.

Distribution is only touched upon slightly, in the sections on tariffs in Belgium and in the Flemish draft decree.

The report closes with conclusions and suggestions for further study.

II. EUROPEAN INSTITUTIONAL DEVELOPMENTS

A. European Directive

1. Introduction

Directive 96/92/EC [1] concerning common rules of the internal market in electricity was adopted by the Council of Ministers on December 19, 1996. It entered into force two months later on February 19, 1997.

Basically, the Directive provides for:

- free competition for generation, with either an authorisation or a tendering procedure for building new generation capacity;
- a market on the consumers' side, that is open to a minimum degree[3]; countries may choose to open their market more than this minimum degree;
- free access[4] to the transmission network, with Third Party Access, or through a Single Buyer, or a mix of these;
- unbundling of accounts between generation, transmission, distribution and other non-electric activities, if these are present within one company; the accounts must be open to the competent authorities;
- public service obligations that may relate to security, including security of supply, regularity, quality and price of supplies and environmental protection.

Chapter VIII
Article 27

Member States[5] had two years to bring into force the laws, regulations and administrative provisions necessary to comply with this Directive. However, Belgium and Ireland had the option to delay the transposition of the Directive by an additional year. Greece has two additional years at its disposal. Member States have to inform the Commission about their implementation before the end of the transposition period.

Consid. 4

The Directive starts with a list of considerations that have led to the Directive. These are important for a clear understanding of the background of the Directive and its overall aims. The ultimate goal is "*to increase efficiency in the production, transmission and distribution of electricity, while reinforcing security of supply and the competitiveness of the European economy and respecting environmental protection.*" Recurrent themes are:

- environmental protection;
- a need for objective and non-discriminatory criteria between the various utilities;
- a natural transmission monopoly and the technical aspects of transmission.

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[3] Certain consumers are defined as "eligible". These consumers only can move on the open market.

[4] Between generators and eligible consumers.

[5] The Directive is a general guideline, to be transposed with a large degree of freedom in national legislation.

2. Generation

Chapter III

For the construction of new generating capacity, Member States may choose between two different procedures or a mixture of both:

- authorisation;
- tendering.

Whatever procedure chosen, it must be conducted in accordance with objective, transparent and non-discriminatory criteria.

a) Authorisation procedure

Under this procedure, any interested person may apply at any time for authorisation (i.e. a license) to construct and operate a power plant. Member States set up criteria for granting authorisations. The criteria, being public, may relate to safety and security of the electricity system installation and associated equipment, protection of the environment, land use and siting, use of public ground, *energy efficiency*, the *nature of primary sources*, characteristics particular to the applicant such as technical, economic and financial capabilities and public service obligations. Applications for investments in new capacity, conform to the criteria for granting an authorisation, must be accepted. The guideline to the Directive [2] clearly states that *lack of demand is not a valid reason for refusal.*[6]

If authorisation is refused, the applicant shall be informed of the reasons, which must be objective and non-discriminatory. The reasons have to be well founded and duly substantiated in the criteria for granting authorisation. The Commission has to be informed about the refusals. Appeal procedures must be available to the applicant.

b) Tendering procedure

The tendering procedure allows Member States to plan the construction of new capacity. The Member State or a competent body appointed by the State draws up an inventory of new capacity to be constructed, including replacement of old capacity. Specifications are published in the Official Journal of the European Communities at least six months before the closing date for tenders. These contain a detailed description of the contract specifications. An exhaustive list of criteria governing the selection of tenders and the award of the contract is also included.

The organisation, monitoring and control of the tendering procedure is carried out by an authority fully independent of electricity generation, transmission and distribution. This ensures objective and non-discriminatory decisions.

Also, even when applying a tendering procedure, certain categories of generators (self-producers, independent power producers) are always able to invest according to the authorisation procedure if they fulfil the criteria.

[6] A lack of demand - or surplus of generation capacity - is indeed not mentioned among the criteria for granting authorisation.

3. Transmission

Chapter IV

Transmission is defined as the transport of electricity by a high-voltage interconnected system with a view to its delivery to final consumers or distribution companies.[7]

The chapter on transmission system operation in the Directive concentrates on technical issues for the transmission system operator. The organisation of the access to the transmission network is discussed in section II.A.6.

Member States designate, or require undertakings owning transmission systems to designate, a *system operator* responsible for *operating, ensuring the maintenance* and if necessary *developing the transmission system* in a given area *and its interconnections* with other systems in order to guarantee security of supply.

The transmission system operator (TSO) is responsible for dispatching[8] the generating units in his area and for controlling the use of interconnections with other systems. The criteria for the dispatching must be objective, published and applied in a non-discriminatory manner. This implies that the TSO is not allowed to favour generating facilities belonging to the same company or shareholders of the company in case the TSO is not totally separated from production. The criteria must take into account the economic precedence[9] of electricity from available generating installations or interconnection transfers and the technical constraints of the system.

For environmental reasons, a Member State may, however, require the TSO to give priority in the dispatching to electricity produced from renewables, waste and from combined heat and power. This is important, as this allows Member States to ensure the sale of environmentally friendly electricity even in cases where its costs exceed the cost of traditionally produced electricity.

Priority in the dispatching can also be given to electricity produced using indigenous fuels but only up to 15% per year of the overall primary energy necessary to produce the electricity consumed in the Member State.

The transmission system operator is obliged to preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its business.

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7 The Directive distinguishes between high voltage transmission, and medium and low voltage distribution. A separation voltage level is not specified, and may be different in different countries, depending on the grid characteristics.

8 Dispatching refers to the process of determining the order in which power plants are called upon to deliver the required power. Economic dispatching refers to an order based on economic criteria, technical dispatching is based on technical requirements (line congestion, voltage and frequency control,…). The Directive does not clarify whether it refers to economic or technical dispatching.

It is also not clear from the Directive to what extend the production utilities can independently decide on the dispatching. In Belgium, the main producer, Electrabel, and other producers submit their proposed dispatching schedule to the system operator, who can accept this or ask for modifications, based on technical grounds such as congestion.

9 The economic precedence is defined as the ranking of sources of electricity supply in accordance with economic criteria. This means the cheapest power plants are the first to be called upon to provide the required electricity, taking into account extra costs such as start-up costs.

4. Distribution

Chapter V

Distribution is defined as the transport of electricity using medium- and low-voltage interconnected systems. Most requirements are similar to those for transmission.

A Member State may also impose an obligation on distribution companies to supply consumers located in its area[10]. The tariffs may be regulated, e.g. a requirement to sell electricity to all private consumers at equal prices per kWh in its area via the imposition of a public service obligation.

5. Unbundling

Chapter VI

The aim of unbundling is to avoid discrimination, cross-subsidisation and distortion of competition. Therefore, integrated electricity undertakings must, in their internal accounting, keep separate accounts for generation, transmission, distribution and retail activities. If they undertake other non-electricity activities, these other activities must be accounted for separately just as if these were carried out by separate undertakings. Member States or any competent authority must have right of access to these unbundled accounts. The annual accounts have to be published.

The separation of activities can be based on management unbundling, legal or ownership separation. Management unbundling requires the establishment of a separate profit centre, managerial independence and the availability of human, financial and physical resources to maintain and develop the network.

6. Access to the network

Chapter VII

Member States can choose between *negotiated or regulated third party access* (n-TPA and r-TPA) or the *single buyer procedure* (SB) when organising the access to the transmission and the distribution network. The single buyer procedures can be with a repurchasing obligation, or with TPA. Whatever option chosen, both sets of procedure shall operate in accordance with objective, transparent and non-discriminatory criteria. Both in case of third party access or single buyer, Member States take measures to enable producers to supply through a direct line (see section II.A.6.d).

a) Negotiated Third Party Access (n-TPA)

Chapter VII
Article 17,
par. 1 to 3

Negotiated TPA is characterised by the fact that producers and consumers of electricity can contract supplies directly with each other, but that they have to negotiate access to the network with its operator. Such negotiations deal with transport tariffs and other conditions.

Chapter VII
Article 17,
par. 5

The system operator may refuse access in case of lack of capacity. The Directive contains no provision that obliges the system operator to construct new capacity in case of lack of

[10] This is part of the public service obligations.

capacity.[11] In case of refusal duly substantiated reasons must be given, in particular with regard to public service obligations.

Negotiations are subject to a dispute-settlement procedure. Member States designate a competent authority, independent of the parties, to settle disputes relating to contracts and contract negotiations, including refusal of access. It is also ensured that none of the parties abuses a possible dominant position.

To promote transparency and facilitate negotiations for system access, system operators must publish indicative prices (average prices over 1 year) for using the transmission and distribution systems. The Commission also publishes, in the interest of increased transparency, the available prices for all Member States on its Internet site.

b) Regulated Third Party Access (r-TPA)

Chapter VII Article 17, par. 4

In case of *regulated TPA*, producers and consumers also contract directly with each other for supply. The price for the use of the transmission and distribution systems can, however, not be negotiated. The eligible consumers have a right of access on the basis of published tariffs. In the case of r-TPA, Member States shall also designate a competent body to settle disputes.

c) Single buyer with repurchasing obligation

Chapter VII Article 18, par. 1 and 2

The *single buyer* is defined in the Directive as a legal person responsible for the unified management of the transmission system and/or for centralised electricity purchasing and selling. This means that the single buyer would normally also be the transmission system operator but not necessarily. The single buyer is not discussed further, as no Member State has opted for this mechanism.

d) Direct lines

Chapter VII Article 21

All electricity producers and electricity suppliers have a right to supply their own premises, subsidiaries and eligible consumers through a direct line[12], when the suppliers have the necessary authorisation. The authorisation criteria for constructing a direct line (to be granted by the Member States involved) must be objective and non-discriminatory. Member States may, however, make authorisation subject to the refusal of system access by the TSO (for reason of lack of capacity of the transmission and/or distribution network) or to the opening of a dispute settlement procedure. Member States may refuse to authorise the construction of a new direct line, if the line obstructs the public service obligations.

7. Market opening

Chapter VII Article 19

The Directive provides for a gradual market opening in three steps: 1st step on February 19, 1999, 2nd step on February 19, 2000, and 3rd step on February 19, 2003. Each Member State

[11] On the other hand, Article 7 of the Directive states that the development of the transmission system in order to guarantee security of supply is one of the duties of the TSO. Supposedly this means the TSO is not obliged to invest in new transmission capacity, if the customer can easily obtain a secure supply from a geographically better located producer. In case the refused contract is financially much more interesting, the producer and customer could request authorisation for investing in a direct line.

[12] A direct line is a line not linked to the interconnected system.

opens the market to such an extend that it respects at least this minimum market opening. The Member States are allowed to go for a further opening, including a complete liberalisation.

The minimum market opening corresponding to the 1st step is calculated as the share of the overall consumption in Europe consumed by final consumers with an annual consumption exceeding 40 GWh per year. This implies that about 26.48% of each national market is opening for competition[13]. In the 2nd step, the threshold is reduced to 20 GWh per year, increasing the minimum market opening to about 28%. In the 3rd step the threshold is further reduced to 9 GWh per year, equalling a market opening of about 33%.

Member States themselves define the eligible consumers to participate in the market opening. The requirement is that the overall consumption of the eligible consumers in a Member State makes up 26.48% of the national consumption in that Member State. However, very large final consumers of over 100 GWh per year must be included in the definition of eligible consumers. Distribution companies supplying eligible consumers are themselves eligible for the share of these eligible consumers. The criteria for the definition of the eligible consumers are published by Member States by the 31st of January each year in the Official Journal of the European Community.

8. Public service obligations

Chapter II Article 3, par. 2

The electricity market and all areas regulated in the Directive are subject to public service obligations, which Member States may impose in the general economic interest, on electricity undertakings in their market. These obligations are defined by the Member States individually. The Member States define these obligations in detail. They must be transparent, non-discriminatory, verifiable and published. The obligations must be notified to the Commission, that will check them against Community law. The obligations have to fall into one of the following four categories: security and security of supply, regularity, quality and price of supplies and environmental protection. Obligations that cannot be categorised among one of these four categories are unacceptable.

The public service obligations allow Member States to balance competition with public services, where this is deemed necessary in the general interest of society. Examples could be an obligation for a distributor to supply all consumers in its area at equal price per kWh or an obligation for the consumers to purchase a certain percentage of their electricity from renewables. It is, however, important that these obligations respect the Community framework, as they by no means should be used to favour domestic electricity producers at the expense of producers in other Member States.

9. Reciprocity

Chapter VII Article 19, par. 5

To avoid imbalance in the rights and obligations of electricity companies due to the differences in market opening, the Directive contains some possibilities for a Member State to

[13] The figure is based on consumption in 1998.

refuse access to suppliers from other Member States, as a transitional measure of reasonable duration. The two conditions that have to be fulfilled are:

- the first Member State, say Member State A, opens a larger *percentage*[14] of the market than the other Member State, B;
- a consumer, eligible in Member State A, wants to contract electricity from a supplier in Member State B, but because of the different opening, the consumer would not be eligible in Member State B.

In this case, Member State A may refuse access to the supplier from Member State B.

10. Regulation

Chapter VII
Article 22

The Member States must set up an independent dispute settlement authority, to ensure equal and fair application of the new market rules, and to avoid abuse of a possible dominant position of market players. Most Member States have set up independent regulatory bodies.

B. Harmonisation process

The EU recognises that the implementation of the Directive in each Member State is only the first step. For the completion of an internal energy market, trade between the Member States has to be facilitated [3].

Major existing or expected obstacles were outlined in the Second report to the council and the European parliament on the harmonisation requirements [4], dating from April 1999.

Three issues were covered in the report.

- The concern to create one common electricity market and not 15 liberalised but separated markets. The cross-border transmission tariff problem is the main obstacle.
- The need for a pan-European regulation in order to address the cross-border issues.
- The necessity to ensure a level playing field on the European market, for the success of the liberalisation process.

The report intended to draw the attention to the complexity of this matter and the possible problems attendant upon it. The following paragraphs summarise the most relevant points in the report.

During the last year, a lot of progress was made, particularly concerning cross-border transmission. In the final paragraph of this section, results of the fifth European Regulation Forum meeting in Florence, in March 2000 [10], are discussed.

[14] The percentage must be different, not the energy consumption threshold level in GWh/year. Reciprocity may not be applied in case both Member States are for example 28% open, but the threshold for this opening is different. Member State A could be open for consumers of more than 20 GWh/year, and Member State B for consumers of more than 30 GWh/year. A 25 GWh/year customer in Member State A can be supplied from Member State B, even if he would not eligible in Member State B.

1. Obstacles for cross-border trade of electricity

The complexity of the cross-border trade is not a new topic. In a preliminary phase, the Commission created the European Regulation Forum (ERF), meeting regularly in Florence. The ERF consists of representatives of the Commission, the Member States, the national Regulatory authorities and TSO's, in close contact with representatives of producers, consumers, traders and market operators. They identified available connector capacity and cross-border tarification as key issues. Under impulse of the ERF, the independent European System Operators, organised under ETSO, worked out a paper on their proposal for rules on international exchange of electricity [5][15]. In parallel, the Commission launched an independent study to evaluate the different proposals. However, the cross-border problems do not only concern Member States but must also be seen in the light of the trade with third countries.

a) Available interconnector capacity

Interconnectors, providing transmission capacity between 2 TSO's, can form a critical point in the single electricity market. Will, after liberalisation, their transmission capacity suffice for the expected increase of power trade? To guarantee the double scope of optimal usage of and fair access to the interconnection capacity, the TSO's must co-ordinate their activities on an overall level. This demands not only a good management of today's available transmission capacity (ATC), i.e. maximisation of the ATC and dealing with long and short term requests, but also a correct expansion policy in proportion with the evolving electricity market.

To maximise the ATC, the TSOs have the duty to use the interconnections in the most efficient way. If not, the refusal of access is not justified. One way to optimise the ATC is the superposition of counterdirected flows[16], which can be done without additional cost. Redispatching, countertrading[17] or market splitting[18] can also be applied to free up remaining bottlenecks. The additional cost can be passed on to the network users.

The above measures should lead to avoiding refusal of access. But, at the short-term market, bottlenecks will never be completely excluded. To regulate the short-term requests, a rationing or auctioning mechanism will be necessary. Because of the multiple regulation possibilities, some kind of harmonisation will be necessary in order to avoid unjustified allocation between the TSOs.

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[15] The more recent ETSO documents are discussed in section II.B.4.

[16] Contractual flows of e.g. 100 MW in one direction and 60 MW in the opposite direction, lead to an actual physical flow of only 40 MW. In this way, the contractual capacity of an interconnection can be larger than the physical capacity.

[17] Countertrading is a system whereby the system operator purchases or sells electricity from generators, or even consumers, that are willing to increase or decrease generation/consumption, in order to create counterdirected flows. Redispatching is an alternative to resolve an existing bottleneck. The system operators of the concerned areas change the dispatching order of the power plants to create overall electricity flows that remain within the limits of the transport line constraints. In either case, there is an extra cost, as the market had tried to achieve a minimum cost situation.

[18] Market splitting is another alternative to deal with a bottleneck, usually applicable in systems which already have a common spotmarket. As a reaction to the occurrence of a congestion, the market operators provide for the possibility that there are different spotmarket prices on either side of the bottleneck. Thus, electricity in the area which is oversupplied becomes cheaper than electricity in the undersupplied area. Consequently less market participants are interested to purchase from the area which becomes more expensive and the resulting flow over the bottleneck is reduced.

Long term capacity reservation can lead to the exclusion of other market participants. Therefore, it is recommendable to avoid such agreements. The Commission will examine individually to what extent the contracts restrict competition while staying fully aware of the fact that the conclusion of capacity reservation agreements may be indispensable in certain cases, e.g. construction of new lines. The Commission, at the time of writing the Second Report, did not intend to set out precise guidelines for potential solutions. However, it could already be said the reservation of transmission capacity must be coupled with the principle: ‘use it or loose it’, unused capacity being offered to the short-term market. The application of this rule needs a transparent policy of the different TSOs permitting the remaining market participants to react in an appropriate way to the instant market situation. An information system could announce the available transmission capacity accessible for all the market participants.

Next to the management of the ATC, the further development of the existing transmission capacity is important. In the free market, new lines must be fully subject to the principle of third party access.

b) Cross-border tarification and settlement

At the moment, no adequate tariff framework for cross-border electricity transactions is operational. This results in a cumulative effect of the national fees when transmitting over several TSO areas, referred to as pancaking. Therefore, it is often cheaper for the consumer to continue with the local supplier instead of choosing a supplier in another Member State, benefiting fully of the liberalised energy market. One of the key issues is to work out a simple tariff framework and a settlement system among the TSOs, allowing them to redistribute the tariff revenues.

General pricing principles

Both parties, customers and TSOs, in an open market have their own demands in the pricing system. Customers ask a simple and non-transaction based system, while TSOs need a cost reflective system. Therefore, an ex ante defined postage stamp tarification is set up for the customers, while the TSOs operate an inter TSO settlement system on the basis of ex post measurements. Clearly, this double approach needs regular feedback and flexible adaptation of the ex ante tariffs. Furthermore, the pricing system needs to respect the unbundling principle. Only the real transmission cost may be taken into account.

Non-transaction based pricing

Physical flows resulting from input to and output from a closely meshed grid bear little or no relation to distance. This can be compared with a lake, where it is irrelevant in terms of cost whether the one who takes water from the lake is situated close to his contractual counterparty who puts water in, or is situated on the other side of the lake. It is the overall position of all inputs and outputs, together with the grid lay-out, that determines the flow pattern, not the individual contracts between producers and consumers.

The correlation between the contract path between producer and consumer and the actual physical flow being very low, the pricing system will be non-transaction based. Rather, a point-of-access charge will be used. This also has the advantage to be simple and it becomes easy for consumers to change from supplier as this system recovers the network costs only through an access charge independent of supplier. Transaction-based systems would require the network users to notify feed in and consumption point for each concluded transaction. Changing supplier implicates in this case a whole new cost calculation.

Transit without pancaking

According to the draft proposal from the European TSOs [5], the total transaction cost T_{tot} can be seen as the sum of a cost G, representing the generator connection cost, a cost L, representing the consumer connection cost and a transit cost T, a weighted sum of the postage stamp tariffs of the crossed TSOs. Index 1 represents the exporting, n the importing and i the transited countries[19].

$$T_{tot} = G_1 + \sum_{i=1}^{n} (k_i \cdot T_i) + L_n$$

As each transit element T_i would contribute to the total fee and would by consequence introduce pancaking, this method of charging transit has been rejected. The G_1 and L_n component would give access to the complete interconnected European network[20].

Congestion pricing

Refusing access in case of congestion can lead to discriminatory allocation of capacity. Therefore, an adequate pricing system must be set up. In fact, the exact cost can only be calculated ex-post but an ex ante estimation, based on the published ATC information, can be made, permitting the customer to accept refusal or to pay the extra costs for access. As the possible solutions in case of congestion are multiple, some kind of harmonisation is needed.

Conclusion

The conclusion is that a non-transaction-based tarification for customers coupled with a settlement between TSOs seems the most adequate solution. A special pricing system to deal with congestion will be necessary.

c) Need for a common commercial policy towards third countries

Due to legal (opening of the market) and technical (links towards third countries) developments in the energy market, the possibility of electricity trade with third countries increases. However, the risk is that non-European member states might claim access to the European customer while having the possibility to maintain monopoly rights in their own area. This leads to unfair competition. To what extent is this acceptable?

If the principle of equivalent market opening and reciprocity is accepted between Member States, it appears logical to equally apply it to third countries and therefore refuse access on

[19] In the proposal, a T-element would also be charged in the generator and consumer control area. The weighting coefficient reflects the extent to which the transit takes place over the considered control area. E.g., a transit from France to The Netherlands, with an 80% flow through Belgium and a 20 % flow through Germany, would lead to $k_{France} = k_{Netherlands} = 1$, $k_{Belgium} = 0.8$, $k_{Germany} = 0.2$.

[20] The method of charging cross-border trade, as partially agreed upon in the fifth ERF meeting, is discussed in section II.B.4.

the basis of this principle. Reciprocity corresponds to an equivalent market opening, equivalent market access conditions and equivalent environmental standards in electricity production. The GATT regulation is unclear about this issue but it is always possible to conclude bilateral agreements between European Member states and third countries based on the reciprocity principles. Those agreements will stimulate a faster market opening, new investment opportunity, modernisation and a consistent environmental policy.

2. Regulation of the electricity network at European level

The existence of a European liberalised electricity market requires some kind of regulation and a tarification system, supervised on the national as well as on the European level, in order to avoid discrimination and excessive pricing and to support reinforcements in the network.

At national level, this task is reserved for the Regulator and Competition authorities. At European level, the role of the Commission is to stimulate the exchange of information between those authorities. In case of disputes at national or European level, EC law and the competition rules of the EU Treaty are applicable.

Concerning cross-border transmission tarification, neither national regulatory action, leading to 15 conflicting opinions, nor the Commission applying the competition rules is fully able to address the issues concerned. In order to deal with this issue a European Regulator can be established, or, it can be tried to reach a consensus between the different TSOs, via the ERF[21].

3. Ensuring a level playing field in the European electricity market.

The third part of the report examines possible distortions of competition within the internal market as a result of diverging legal standards, mainly affecting the cost of electricity generation. This chapter focuses on three specific areas. First, environmental standards, second, accounting standards for nuclear decommissioning and third, taxation.

a) Environmental standards in electricity production

Environmental standards, mainly those focussing on air pollution, influence the choice of generation technology and therefore the cost of electricity generation. This chapter discusses the existing secondary EU legislation as well as new developments on environmental policy.

Actually, there exist three main directives dealing with large combustion plants. Directive 84/360 sets a framework for dealing with air pollutants from industrial plants and introduced principles as prior authorisation of construction of industrial processes and use of Best Available Technologies Not Entailing Excessive Cost (BATNEEC). LCPD, the Directive on controlling Emissions from Large Combustion Plants sets out emission standards for particulates, SO_2 and NO_x, and emission ceilings for SO_2 and NO_x. Finally, Directive 96/61/EC concerning Integrated Pollution Prevention and Control (IPPC) requires the introduction of an integrated environmental licensing system, which will apply to a range of industrial processes, including power stations larger than 50 MWt.

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[21] Results from the latest ERF meeting are discussed in section II.B.4.

The following developments will affect pollution control for power plants in the EC:

Air Quality	Stringent national caps for SO_2 and NO_x and particulates and lead
Acidification	Reducing SO_2 emissions across the EC by placing restrictions on the sulphur content of certain liquid fuel products
Revision of LCPD	Overall update, promotion of CHP (Combined Heat and Power)
Water	A special Directive on water would set standards and mechanisms for ensuring that limit values under the IPPC Directive are observed.
Waste	Will be covered by the IPPC Directive and by the EC's existing legislation on waste.
Kyoto Protocol	Under the Kyoto Protocol, the EC is committed to reducing greenhouse gases emissions by 8% by 2008-2012. In relation to 1990 levels.

The Commission is examining the measures that need to be taken at Community level to ensure equivalent competitive conditions as a result of environmental requirements to meet the above-formulated requirements.

b) Standards for nuclear decommissioning

Unlike other types of generation, nuclear power plants must include in their cost a factor for the storage of nuclear waste and future decommissioning of the plant. Diverging regulatory approaches to the management of decommissioning funds may cause market distortions.

At the moment, there is no specific EC legislation on the decommissioning of power plants, but, within the single market, a common approach will be needed, also leading to a better protection of population and environment, to a reduction of waste,… .

According to the Commission, decommissioning costs must be seen as part of the electricity production and may not be cross-subsidised from the transmission activity nor directly subsidised via state aid. To identify the decommissioning cost, a detailed preliminary study must be executed taking into account all the relevant factors such as safety, environmental and financial issues,…. . The fund must be secured and controlled by the mandated authorities and only dedicated to decommissioning. The full fund must be available at the foreseen time.

c) Taxation

Indirect taxation

There are two systems of indirect taxation, which apply to electricity. The first is VAT, harmonised at community level, and the second is a series of national single stage taxes not yet regulated at Community level.

According to the VAT directive, the standard VAT rate of 15% to 25% applies to electricity. Only exceptionally, a reduced rate of no less than 5% applies if no distortion of competition exists. It is not allowed to apply different VAT rates according to the production process of electricity.

In its proposal for a Directive restructuring the Community framework for the taxation of energy products (COM(97)30) the Commission is proposing to harmonise taxation to all kinds of energy sources.

Concerning electricity, the Commission has decided to tax it at output level, meaning that the electricity is taxed in the country where it is consumed. Therefore, it is not permitted to differentiate taxation on the basis of the quality of fuel used but it is allowed to differentiate on the type of user. In the light of a possible certification system of renewable based electricity producers, a differentiated taxing of electricity from such certified renewable based generators could be possible. Under the proposal, Member States can, for environmental purpose, apply additional taxation to inputs, while respecting the competition rules.

Direct taxation

In the field of corporation tax there is no harmonisation of tax bases on which corporation tax is levied.

4. ERF Meeting in Florence

In the fifth ERF meeting in Florence, on the 30th and 31st of March, 2000 [10], some common views on cross-border tarification mechanisms and congestion management have been produced, based on the ETSO proposals [7], [8], [9].

a) Cross-border tarification mechanism

It had already been agreed, at the fourth ERF meeting on the 25th and 26th of December 1999 [6], that each TSO's network costs would mainly be recovered through the G and L charges imposed on local network users. However, "cross-border transactions (CBTs) cause individual power systems to incur extra costs, and this fact justifies that some additional network charges could be recognised due to the existence of CBTs". It was equally recognised that any approach [to a cross-border tarification mechanism] put forward by ETSO should "meet the basic principles of non-discrimination, cost-reflectiveness, simplicity and transparency". Furthermore, " an approach based on a factor of the level of losses and an element to take account of relevant and necessary investment to be incurred/incurred in each transmission system network due to international trade, should in principle form the basis of the final approach in this area."

The general philosophy of the ETSO proposal on cross-border tariffs [8] relies on six main phases:

- Within the overall costs incurred by a TSO, allocation of costs related to national transmission services and to cross-border exchanges.
- Computation of the total revenue needed at the European level to cover the costs related to cross-border exchanges.
- Computation of the value of the European fee by dividing the required total revenue by the sum of the expected programmed cross-border exchanges.
- Payment of the European fee by market participants who export electricity.
- Collection of the TSO revenues related to exports.
- Redistribution of the collected revenues according to a measurement of the cross-border exchanges based on hourly measurement of the energy flow at the tie-lines.

This requires harmonised definitions of the following elements:

- Identification method for the "Horizontal Network" (totally or partially used by cross-border exchanges)[22].
- cost accounting and allocation methods for the elements of the horizontal network.
- Method to assess, ex-ante, the cost of losses on the horizontal network.
- Method to assess, ex-ante, the volume of electricity that would be exported.
- Method for computation of the cross-border fee.
- Ex-post measurement and aggregation method for the volume of electricity exchanged between countries.
- Settlement method for year N and N+1 in case of differences between expected and real revenues.

The following points from the ETSO proposal were accepted at the ERF meeting:

- A system based on inter TSO payments will be established to compensate for the cost of physical flows in the form of transits[23] and loop flows, resulting from imports and exports in the internal electricity market (IEM).
- The initial system of cross-border pricing shall apply to the ETSO members of the interconnected UCTE network[24].
- In the short term, a full and accurate calculation of costs is not possible. A tarification system should be commenced based on available figures, while a process of refinement is undertaken. The aim is to obtain a cost reflective, transparent, simple, non-discriminating tarification mechanism that gives appropriate cost allocation signals to market players.
- An initial system should be put into place for one year.

The representatives of the Commission, the Regulatory authorities and the Member States feel that the method of raising and disposing of funds within each TSO should be left to subsidiarity. The methods chosen may not lead to distortion in the electricity market. The following decisions need to be taken:

- For a transitory period of one year from 1 October 2000 to 30 September 2001 an amount should be distributed among continental European TSOs as a compensation for CBT related costs of TSOs. The sum of 200 million euro put forward by ETSO is a basis for

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22 This is the highest voltage level part of the network, usually 400 kV, plus a part of the lower voltage levels for those countries with highly meshed networks on lower voltage levels.

23 It should be noted only transits are renumerated, not import or export separately. In each hour, the minimum of measured import and export flows would be taken, and summed over the entire year. These values for all countries form the basis of the allocation key of the fund between the different countries [9], paragraph III.

24 These are: Austria, Belgium, France, Germany, Greece, Italy, Luxembourg, The Netherlands, Portugal, Spain and Switzerland. Other ETSO members are: Denmark, Finland, Norway and Sweden (together with Iceland, they form Nordel), the United Kingdom (i.e. UKTSOA), and the Republic of Ireland (i.e. ATSOI). Separate arrangements for cross-border tariffs may apply on a case-by-case basis to DC interconnectors with these areas. The Eastern European countries that are part of the UCTE interconnected network are not part of ETSO.

this level of compensation but needs to be analysed in detail by the European Commission, the Regulatory authorities and the Member States.

- The amount will be generated via payments of individual TSOs according to the past net measured exiting physical flows minus entering physical flows at individual TSO level. That amount will be distributed as a compensation of TSOs according to the allocation key proposed by ETSO, i.e. in accordance to the past transits recorded by TSOs
- The way charges to domestic customers are modified is subject to subsidiarity. Existing import/export charges will be abolished, once the new mechanism enters into force, which should be no later than 1 October 2000.

A more detailed explanation from ETSO is needed on a number of other points, such as the definition of the horizontal network, the cost thereof, the cost of losses and the way the share of the overall cost due to CBTs is calculated. Further collaboration from all parties involved should lead to a refined system by September 2001. It is also noted that CBT related TSO payments should be based on the net physical flows associated with CBTs and should reflect locational factors.

A last and very important point, stressed by different parties, is the need for harmonisation of the division of transmission charges between G and L components.

b) Congestion management

Less progress has been made on the issue of congestion management. ETSO publishes twice yearly the available transmission capacity on interconnectors between control areas. However, the representatives at the ERF meeting ask for more clarification on the definitions used. Also, the TSOs should provide information on a shorter time scale, relative to the time scale used by market players.

Congestion management should be based on market solutions that give proper and justified incentives to both market parties and TSOs to act in a rational and economic way.

The Commission intends to propose a revision of the Trans European Networks (TEN) guidelines for the energy sector, in order to focus them on the needs of the internal market for electricity. This TEN programme is the main instrument at a European level to address congestion issues through extending interconnection capacity. The annual fund for the co-funding of studies relating to energy networks (electricity and gas) is of the order of 20 million ECU.

III. IMPLEMENTATION IN EUROPE

A. Overview European countries

Table III.1 gives an overview of the implementation choices in the 15 countries of the European Union. Table III.2 gives a number of facts and figures concerning import and export, and changes in industrial and household tariffs. Germany, The Netherlands, France, UK/Wales and the Scandinavian countries are discussed in more detail in the following sections. Special attention is given to the new transmission tariff system in Germany and The Netherlands. Some other countries are discussed briefly here[25]. Overall level of opening at the moment is 65% [].

1. Austria

Hydro production alone is sufficient in summer, but 30% of production has to be from other sources for security and economical reasons. This means there is overcapacity in summer, normally leading to low prices. Additionally, the production cost in the winter is a lot higher. The expensive winter costs are partially recovered through levelling out the price difference winter-summer. Austria has 27 interconnections, with an overall capacity larger than the Austrian production. Part of this interconnection is with Eastern Europe, with lower environmental regulations. Therefore, the question of import from third countries is important for Austria. The government proposes to completely open the market by the end of 2001.

2. Denmark

In the existing legislation, there was a no-profit rule for all market players. Under the new rules, the profit for transmission and supply to non-eligible consumers is regulated, and free for production and trading. Denmark has a lot of CHP, and a growth in renewables.

3. Greece

Greece has an extra two years, i.e. they have to open their market by 19/02/2001. A lot of issues still have to be addressed. Greece has interconnections with Albania, the Former Yugoslavic Republic of Macedonia and Bulgaria. These interconnections and most of the production are in the North, while the load centre is around Athens, leading to a strong geographical unbalance. The transmission tariff will probably be a postage stamp, possibly with different zones. Greece is a member of UCPTE, but is not synchronous with the main part of the UCPTE grid.

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[25] Information is taken mainly from [12], [13], [14] and [15]. Country specific information is taken from [16] (Greece), [17], [18] and [19] (Ireland), [20] (Italy), [21] (Spain) and [22] (UK).

4. Ireland

Like Belgium, Ireland had an extra year, i.e. they had to open their market by 19/02/2000. The Electricity Act 1999 is into operation, and the Commission for Electricity Regulation, CER, is fully active and working on a Grid Code. Ireland has a 600 MW interconnection with Northern Ireland. Together, they are for the moment still isolated from other power systems. It is planned to upgrade this link to 1000 MW. Maximum production capacity in Ireland is 4350 MW, which means the margin with expected winter peak demands of 3800 MW is very small. The last new power station was build 12 years ago, and new power stations are not expected before 2002. Some sources fear power cuts may become necessary.

5. Italy

ENEL controls 80% of production, but must reduce this to less than 50% by 1/1/2003. At the end of October 1999, the stock market sale of 30% of ENEL was launched.

6. Luxembourg

80% of electricity is imported from Belgium and Germany. As the interconnecting transmission lines have no other function than this interconnection, they are considered as part of the distribution network. Hence, there is no separate TSO, only a Distribution System operator.

7. Spain

Production larger than 50 MW has to bid via a pool. There is a limited cross-border transmission capacity with France. The transmission system operator calculates and publishes the marginal loss coefficients for all 400-220 kV nodes, hour by hour. At the moment, they are not yet used as part of the transmission tariff, but transmission network losses are being considered as an element to be taken into account when deciding on the location of new production plants or loads.

8. Sweden

There are still a lot of long term contracts. Industrial customers also pay for the local grid.

9. UK, other than England/Wales

In Northern Ireland the market was opened for large businesses on the 1st of July, 1999. Northern Ireland has no interconnection with the rest of the UK, although a 500 MW undersea link with Scotland will be build by the end of 2001. England and Wales are discussed in section III.E.

	Legislation	New production	Opening 1999 [%]	Opening 2007 [%]	TPA	Pool	Unbundling	Regulator	Reciprocity
Austria	19/02/99	A	28	50	r		L	Indep.	Y
Belgium	29/04/1999; royal decrees needed	A	34	100 for trans.	r		L	Indep.	Y
Denmark	1/01/1998; 19/2/99; 2nd half 99	A	90	90	r		O	Indep.	N
Finland	1995; 2nd half 1998	A	100	100	r	P	M	Indep.	N
France	end 1999 - early 2000?	A	28	33	r		M	Indep.	N
Germany	29/04/1998; New "Verbändevereinba-rung" for 1/1/2000	A	100	100	n		M	Competition law	Y
Greece	2nd half 1998 draft law; time until 19/2/2001	A	30	undecided	n		L	Indep.	N
Ireland	1/12/1998; time until 19/2/2000	A	30		r		L	Indep.	N
Italy	31/03/99	A	30	40	r	P	L	Indep.	Y
Luxembourg	under discussion	A	45	45	r		L	Indep.	Y
The Netherlands	1/08/98	A	33	100	r		O	Indep.	Y
Portugal	1995; amendments in 1997	T	28	33	r		L	Indep.	Y
Spain	1/01/98	A	33	100	r	P	O	Indep.	Y
Sweden	1/01/1996; 1/1/98; may/99	A	100	100	r	P	M	Indep.	N
UK	1990; Amendments expected end 1999	A	100	100	r	P	O	Indep.	N

A: Authorisation, T: Tendering   r: regulated TPA, n: negotiated TPA;   P: Pool;   L: Legal, M: Management, O: Ownership;   Indep.: Independent regulator

Table III.1 Implementation choices in the 15 Member States [12], [13], [15]

	Production TWh	Import TWh	Export TWh	Consumption TWh	1999 cf. 1998	Price households, % drop	Price industry, % drop
Austria	58.5	11.7	13.5	56.7	1.8 TWh net export cf. 0.2 TWh net export 29% increase in export		
Belgium	81.0	9.0	8.3	81.7	0.7 TWh net import cf. 1.6 TWh net import 32% increase in export	12	0.4
Denmark	36.9	5.0	7.3	34.5	2.3 TWh net export cf. 4.4 TWh net export 84% increase in import	6	0
Finland	66.6	11.4	0.2	77.8	11.2 TWh net import cf. 9.3 TWh net import insignificant export		
France	493.5	4.8	71.1	427.3	66.3 TWh net export cf. 61.9 TWh net export	22	12
Germany	509.4	39.4	38.5	510.3	0.9 TWh net import cf. 0.5 TWh net export	23	21
Greece	45.4	1.9	1.4	45.9	0.5 TWh net import cf. 1.6 TWh net import	60	14
Ireland	20.7	0.3	0.1	20.9	no significant import/export	18	0.78
Italy	252.6	42.7	0.5	294.9	42.2 TWh net import cf. 40.8 TWh net import	27	6
Luxembourg	0.9	6.1	0.6	6.4	5.5 TWh net import cf. 5.5 TWh net import	10	3
The Netherlands	79.6	19.4	0.3	98.7	19.1 TWh net import cf. 11.8 TWh net import 58% increase in import	0	5
Portugal	35.7	4.3	5.0	35.0	0.7 TWh net export cf. 0.3 TWh net import	47	21
Spain	189.8	11.9	6.2	195.5	5.7 TWh net import cf. 3.4 TWh net import	36	15
Sweden	150.2	8.5	15.9	142.7	7.4 TWh net export cf. 8.7 TWh net export		
UK	338.3	14.2	0.3	352.2	13.9 TWh net import cf. 12.5 TWh net import insignificant export	40	19

Price drops households: 1998 cf. 1994, 7500 kWh/year, tax included, deflated; industry: 1997 (2) cf. 1994, 10 GWh/year, VAT excluded, deflated

Table III.2 Facts and figures on import/export [23] and industrial and household price changes [12]

B. Germany

1. Market structure

The electricity industry in Germany consists of almost 1000 companies[26]. On the highest voltage level, 8 “Verbund” generating companies control most of the production and also the transmission in their area (Figure III.1):

- Bayernwerk
- BEWAG (Berlin)
- EnBW (Baden-Württemberg)
- HEW (Hamburg)
- PreussenElektra
- RWE Energie (Nordrhein-Westfalen)
- VEAG (former East-Germany)
- VEW Energie (Nordrhein-Westfalen)

Figure III.1 Verbund companies in Germany [24]

VEAG is owned for 75% by the three largest utilities, RWE, PreussenElektra and Bayernwerk. Together, the 8 Verbund companies produced 81% of the energy in 1996. Each company has reserve capacity, leading to a 10 GW overcapacity in Germany as a whole. There is no national dispatch co-ordination or transmission system operator, only a co-ordination of the 8 Verbund companies.

For Belgium RWE is of most importance because it is one of the biggest companies, and its main operating area lies just across the Belgian border.

[26] Information is taken from [12] to [14] and [24] to [31]

In Germany, pooling and load management is performed by regional and municipal distribution system operators, each with their own areas, defined by demarcation contracts. Of the more than 900 municipal companies, 538 organise their own distribution and supply. 300 of them also have production facilities, mainly CHP. Overall, in 1996, 10% of production was generated by municipalities and 9% by regional companies. On the distribution level, consumers in some areas are supplied directly by the generating companies (34% of overall distribution), in others through the 70 or so regional (39%) and the more than 900 municipal (27%) distribution companies.

The very complex market is becoming very active, from the large industry down to the household level, with new players trying to enter the market. The dominant players try to maintain or increase their market share, but their profit margins are decreasing. For example PreussenElektra saw a 43% drop in profit, from the first quarter of 2000 compared with the last of 1999 [Die Welt, 12/5]. RWE announced a drop of 23% [Die Welt, 17/5]. Furthermore, there is a strong competition from cheap electricity from nuclear power plants in France. It is no surprise that the number of take-overs, mergers or cross-participations has increased dramatically.

Recently, the holding companies VEBA and VIAG merged into EON, making the combination of their daughter companies PreussenElektra and Bayernwerk (together 180 TWh) larger than RWE.

In its turn, RWE announced a merger with the other utility in Nordrhein-Westfalen, VEW. With an annual production of 212 TWh, this makes them the largest producer in Germany, and the third largest in Europe, after EdF (455 TWh) and ENEL (225 TWh).

EdF is the most likely candidate to buy 25% of EnBW. Finally, HEW is now only for 25% owned by the city of Hamburg, the major shareholder being the Swedish utility Vattenfall. Other shareholders are PreussenElektra and the Swedish utility Sydkraft.

On the legal side, the Bundeskartellamt is responsible for checking the compliance with the anti-trust rules. They had already announced reservations about the creation of a duopoly of EON and RWE/VEW, that would also control VEAG [26]. Both the European Commission and the German Kartellamt recently accepted the mergers of VEBA-VIAG and RWE-VEW, under certain conditions:

- RWE, VEBA and VIAG have to withdraw from VEAG. This would clear the road to form a third major German player around VEAG-HEW-BEWAG.
- The 0.25 pf/kWh transit fee between the North and South trading zones in Germany (see paragraph III.B.4) has to be abolished.
- VEBA has to provide sufficient capacity at the Danish border for import from Scandinavia.

In the mean time, talks are reported between EON and the French utility Suez-Lyonnaise des Eaux, and initial talks between RWE and the French multi-utility conglomerate Vivendi.

We will not attempt to give an overview of the changes in ownership on the regional and municipal level.

2. Industrial prices and production mix

Industrial prices are the highest in Europe, due to the expensive indigenous coal and lignite (brown coal), subsidised in one way or the other to secure jobs. VEAG in particular is very expensive because of the heavy investments in upgrading their lignite power plants in order to limit pollution. It would take another 5 to 6 years before their cost of producing electricity would drop down to present market prices [].

A large amount of CHP plants is being built. Utilities are obliged to buy power from renewables at premium rates. Wind power capacity had reached the 4.4 GW level by the end of 1999.

Energy-Source	TWh	%
Hydro	19.1	4.2
Nuclear	151.9	33.7
Lignite	125.3	27.8
Coal	119.3	26.5
Fuel Oil	3.3	0.7
Natural Gas	27.1	6.0
Other	4.8	1.1

Table III.3 Fuel Mix in Germany

The government of SPD and the Green party strongly opposes nuclear power. The 14th of July, 2000, an agreement was reached with the sector on the overall amount of electricity that could still be produced in nuclear power plants before their shut-down (i.e. 2600 TWh). This would amount to closing down the 19 nuclear power plants after an average period of operation of 32 years.

3. Legislation and Verbändevereinbarung

The liberalised situation in Germany is characterised by a combination of legislation and voluntary agreements between the market players or “Verbände”.

The new German energy law [30] entered into force on April 29, 1998. Access to the grid is through negotiated TPA, with however a Single Buyer option for distributors until 2005. The degree of market opening is 100%. Disputes are referred to the cartel authorities. It is the intention to protect East German lignite production, covering 70% of the local production, until 2003. Electricity from renewables gets a preferential treatment, with guaranteed take-off at minimum prices. CHP stands for 4% of overall production, but in certain areas the proportion of CHP can be as high as 50 to 80%. Priority is given to the heat driven portion of the CHP power production.

The market players are represented by:

- VDEW (Vereinigung Deutscher Elektrizitätswerke) for the generating utilities;
- VIK (Vereinigung der Industriellen Energie- und Kraftwirtschaft) for the autogenerators;
- BDI (Bundesverband der Deutschen Industrie) for the industrial consumers.

The VDEW works together with three other organisations:

- DVG (Deutsche Verbundgesellschaft) for the eight Verbund generating companies;
- ARE (Arbeitsgemeinschaft regionaler Energieversorgungsunternehmen) for the regional companies;
- VKU (Verbund kommunaler Unternehmen) for the municipal companies.

Their agreements on transmission tariffs are known as the first and second "Verbändevereinbarung", dating from April 1998 and September 1999 [31].

In the first Verbändevereinbarung, valid until the end of 1999, transmission tariffs were transaction based, i.e. both producer and consumer had to be known for each individual transaction. The tariff was a combination of postage stamps for different voltage levels, and entailed a distance-related component if more than 100 km of the highest voltage level were used. This made the transmission tariff a hindrance for free trade.

The second Verbändevereinbarung replaces the transaction model with a point of connection model, without distant component. This model is more in line with the ETSO proposal, as discussed in section II.B.1.b). It started on January 1, 2000, and is valid for two years. It should facilitate market operation, as the link between producers and consumers for each contract is no longer needed. A consumer can switch producers, without changing his connection contract. This will also enable working with a power exchange, like the EEX or European Energy Exchange, in Frankfurt, or the LPX in Leipzig.

4. *Transmission tariff in the new Verbändevereinbarung*

Germany is divided in eight control areas, defined by the eight Verbund companies. The areas controlled by VEAG, PreussenElektra, VEW Energie, HEW and BEWAG form the newly defined trade zone North (the light areas in figure III.1), whereas the areas controlled by EnBW, RWE Energie and Bayernwerk form the trade zone South. Within one control area, each trader, producer, consumer or other market player has the right to build a balance area[27], where his production and consumption are added to obtain the net balance.

Network users pay one annual amount, depending on their annual consumption[28] and the voltage level of their connection. The amount is based on calculated costs, taking into account the use of the voltage level at which the client is connected, and all higher voltage levels including those from neighbouring areas. The cost of ancillary services[29] and system losses is calculated globally, based on the net balance of the balance area. Theoretically, all clients

[27] "Bilanzkreis". This probably does not have to be one geographical area. Different production and/or consumption sites may be added, if they are part of the same undertaking and are within one control area.

[28] The term "Leistung" is used, which actually means "power", but from the context it is clear the energy consumption is meant. The cost depends on the "Gleichzeitigkeitsgrad", i.e. the cost of ancillary services and of covering energy losses in the grid depends on the instant of energy consumption.

[29] "mit Ausnahme eventueller Erhöhungsbeitrage für erweiterte Toleranzbänder". This is in line with the general philosophy of offering a standard quality level, and charging extra for clients demanding a higher quality of service.

participate in covering the network costs, but for the time being generators do not pay anything, pending a European decision[30].

Autogenerators can order reserve capacity. For this, they pay at least 30% of the charge to a normal consumer for the same power demand. If they exceed the ordered capacity, they pay 100% of the normal cost for the part exceeding the ordered capacity.

Production from renewables and CHP plants receives a credit from the system operator, equal to the avoided tariff in the considered voltage level. The same rule applies for all existing decentralised production[31].

Transmission between the two trade zones, or with neighbouring countries, is charged with 0.25 pf/kWh for the net balance of the balance areas[32].

Production and consumption schedules are in general not subject to authorisation. Exceptions exist for regularly appearing bottlenecks, and for large transactions between control areas that could affect system security. In the former East-Germany, art and origin of the produced energy as well as the intended consumer have to be indicated, in order to implement the protection rules for lignite.

The tariff for households and other small consumers is based on average load profiles, avoiding the necessity of installing expensive measurement devices.

Benchmarking is used to check the overall transmission tariff levels.

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30 In the end, all costs are transferred to the consumers, but for international competition it is very relevant whether or not generators initially pay part of the transmission cost.

31 Defined as production connected to a voltage level < 220 kV

32 The EC demands this fee to be abolished. See paragraph III.B.1.

C. The Netherlands

1. Introduction[33]

The Dutch electricity supply industry was restructured in the late 1980's. There are four main, regionally based producers, UNA, EPON, EZH and EPZ, co-ordinated through SEP, the electricity generating board. Under the new Electricity Act 1998, SEP has appointed TenneT as national system operator. When the intended merger of the four utilities failed in April 1998, they became vulnerable to foreign take-overs, due to their small size (10 to 20 TWh produced in 1998) and poor capital reserves. Three of them have already been taken over by larger foreign companies: UNA by the Texan firm Reliant Energy, EZH by the German PreussenElektra, and very recently EPON by Electrabel. Only EPZ is still owned by the Dutch utility PNEM-MEGA.

Together, the four companies have a capacity of some 15 GW, producing approximately 60 TWh, or 61% of total consumption in 1997. Of the total consumption of almost 100 TWh a further 6% was generated by the energy distribution companies, 20% by other decentralised producers and 13% was imported.

CHP capacity from autoproducers was 5.3 GW in 1997, expected to rise to 7 GW in 2000. Distributors are forced to buy any surplus output at avoided cost prices, guaranteeing a return for the independent ventures whatever the supply/demand situation.

Domestic tariffs are cheaper than in neighbouring countries, industrial tariffs are comparable.

2. Implementation of the Directive

a) Introduction

The electricity act 1998 [34] is a framework measure, further developed in the form of supplementary legislation.

The Netherlands opt for a regulated third party access (r-TPA) based on a postage stamp system, related to the consumer price index, and with a deduction based on benchmarking to increase system operation efficiency (RPI-X). There are no specific requirements for new generation: they apply an authorisation procedure.

The electricity market will open further than the minimum specified in the Directive.

[33] Information is taken from [12] to [14], [28] and [32] to **Error! Reference source not found.**

Year	Will get free access	Opening
1/1/1999	P > 2 MW or E > 20 GWh	33 %
1/1/2002	I > 3*80 A	66 %
1/1/2006	I < 3*80 A	100 %

I = Current, P = Power, A = Ampere, E = Energy consumption

Table III.4 Market opening [14]

b) System operation

The Dutch system does not distinguish between the transmission and the distribution grid, but between the national and regional networks. There is one national system operator, TenneT, and a total of 22 regional system operators, all of them separate legal entities.

TenneT is responsible for the grid for voltages of 220 kV and higher, and for the cross-border connections from 500 V and higher.

All system operators offer so-called grid services:

- connection to the grid, plus metering if required, and
- transport of electricity, including extending and maintaining the grid, solving congestion problems, compensating transmission losses, maintaining voltage through reactive power regulation, and general operation of the system.

Only TenneT also offers system or ancillary services:

- maintaining a safe and reliable electricity supply;
- generation-load balancing;
- black-start capability;
- meeting international agreements regarding import and export.

c) Program responsibility

Eligible consumers, traders, brokers, distributors and producers are responsible for their program, i.e. they have to inform the regional system operator of their expected transmission requirements, and the national system operator of their expected energy requirements. This allows the system operators to calculate the expected load flows, and to intervene in case of congestion or other problems. Deviations are covered by the national system operator and charged to the market players.

Essential in this process is metering and data communication.

d) Regulator

To control the liberalised market, a Regulator DTe "Dienst Uitvoering en Toezicht Elektriciteitswet" has been appointed by the Minister of economic affairs. It is fully active, and publishes the relevant rules, codes and decisions on the internet.

The three main parts of the technical code are [35]:

- Grid code: covers rules between system operators and clients – i.e. everyone connected to the grid – and treats import, export and transit;
- Metering code: covers technical characteristics of the measurement equipment and the data communication;
- System code: describes the obligations of all parties involved, to allow TenneT to fulfil the system services and generation-load matching.

In the following sections, the transmission tariff and the rules for import, export and transit are discussed, as an example of a completely defined system. Finally, the supply to non-eligible or protected consumers is discussed.

3. *Tariff structure*

The tariff consists of a connection, a transport and a system tariff [38]. Some of these are voltage level dependent, with five voltage levels defined by the regulator: extra high voltage (380/220 kV), high voltage (150/110 kV), intermediate voltage (50/25 kV), medium voltage (1-20 kV) and low voltage (400 V).

a) Connection tariff

The connection tariff covers the cost of the initial connection and its maintenance. It consists of at most three parts: the initial cost, a monthly amount to cover the capital cost of re-usable assets (e.g. the transformer) and a monthly amount for maintenance. The tariff depends on the connection capacity.

b) Transport tariff

The transport tariff is divided in a transport dependent and independent part. Transport dependent costs relate to solving congestion, compensating losses and maintaining voltage and reactive power balance, depreciation of assets, return on investments, extension and maintenance of the grid and operational costs. Transport independent costs are metering and data communication costs and the costs of organisations responsible for checking the application of the Metering Code and for defining the LUP (cf. later).

The transport dependent costs are covered for 25% by the producers, connected to the extra high or high voltage grid (including import), and for 75% by the consumers. The producers tariff is known as the LUP ("Landelijk uniform producenten transporttarief"), and is based on the kWh supplied to the grid. For consumers, costs of higher voltage levels in the grid are cascaded to lower voltage levels.

Transport independent costs are divided in proportion of the cost caused by each player.

Costs of reactive power are charged to consumers operating at a power factor $\cos\phi < 0.85$ for an inductive load or for any capacitive load, and to producers exceeding 0.9 inductive or capacitive, based on the kVArh.

c) System tariff

The System tariff covers the cost of regulating and reserve power, black start capability, reliability of the grid and general system operation costs. It is to be covered by all network users, proportional to their kWh consumption.

d) Tariffs in 2000

The TenneT tariffs for 2000, for the 380/220 kV grid, are given in table III.5.

Tariff		NLG	
Connection tariff:	new connection:	250 000	NLG
	annual fee	12 500	NLG / year
Transport tariff:	per connection:	30 000	NLG / year
	for system operators:	10.80	NLG / kW-year
	for consumers:	*	
	for producers:	0.00195	NLG / kWh
	for import:	0.00195	NLG / kWh
System tariff:		0.0041	NLG / kWh consumed

*: consumers pay the tariff of their local system operator, even when connected to the 380/220 kV grid

Table III.5 Extra high voltage transmission tariffs in The Netherlands, 2000 [36]

On top of this, TenneT charges 400 million NLG in 1999 and 2000, used for improving production efficiency. This amounts to 0.0029 NLG/kWh for consumers and 18.21 NLG/kW-year from the regional system operators.

e) Price cap

The regulator announced the method for determining the price cap X on the transmission tariffs [40]. In 2001, 2002 and 2003 X will be based on benchmarking with a group of "best-performing" companies, defined by DTe. For 2001, X will be set in August 2000. For 2004 till 2006, X will be based on the average performance of the different system operators ("yardstick regulation").

4. *Import, export and transit*

a) Situation

The Netherlands have six main interconnections, three with Germany and three with Belgium, of an algebraic overall technical capacity of 11 625 MVA. However, electric power flows are determined by the layout of the grid and the production and consumption nodes. Actual capacity is limited by the weakest link, taking into account the possibility of failure of a single power system element ((n-1)-security). For The Netherlands, this means the German part of the links from Maasbracht to Germany limit the import capacity (TTC, Total Transfer Capacity) to 3 500 MW. During maintenance, abnormal production schedules, and during night and morning hours, the capacity is smaller. With an import capacity of 25% of peak demand, The Netherlands is only preceded by Austria and Switzerland.

During the summer of 2000, RWE will increase the capacity of the links with Maasbracht, resulting in a 400 MW increase in import capacity for the Netherlands [36].

An accurate prediction of available capacity could become possible through a better exchange of information, not only regarding the grid configuration and loading, but also with respect to production. This information is commercially sensitive, and not all TSO's are ready for this level of co-operation within the newly founded association of European TSO's (ETSO).

Of the 3500 MW, 300 MW is reserved for international support (TRM, Transmission Reliability Margin).

b) Assigning limited capacity: New rules DTe

In 2000, net available capacity (NTC, Net Transfer Capacity, i.e. TTC minus TRM) is divided between:

- long term SEP contracts[34];
- annual contracts;
- spot market contracts.

A maximum of 2300 MW is available for the long term and annual contracts. SEP contracts have the preference. Remaining capacity is proportionally divided between the requested annual contracts. To prevent abuse, annual capacity can only be requested for the amount of delivery contracts, and to a maximum of the capacity available for annual contracts. Transit is considered as import and export. Remaining capacity, i.e. a minimum of 900 MW under normal circumstances, is available for APX. If annual capacity is not used, it becomes available to APX as well. Expected available capacity is published on an hourly basis, 30 days ahead, by TenneT.

Discussions are under way for a new allocation mechanism from 2001 on, probably based on auctioning [36]

5. *Supply of electricity*

The supply of electricity to protected consumers is only possible with a license. For each area there is only one licensee. This licensee gets in this manner a *monopoly* in his area; on the other hand he has a *delivery obligation*. The distributors of the moment are preferred to become a licensee. To avoid cross-subsidies a licensee keeps separate accounts for the supply to protected consumers. The Minister of economic affairs and not the regulator will control the licensee. The Minister sets the tariffs and approves the provisions for a secure supply.

[34] The contracts with VEW, EdF and PreussenElektra are for 1600 MW until 2003, 1000 MW until 2006 and 750 MW until 2010.

D. France

1. Background[35]

France is by far the biggest exporter of electricity in Europe, due to its excess of baseload nuclear power. Net export in 1999 was 66 TWh. The state-owned monopoly company EdF (Electricité de France) supplies 30 million clients in France, and through international partners more than 16 million outside France, mainly in Great Britain (London Electricity and South West Electricity), Hungary, Brazil and Argentina, but also in Austria, Sweden, Switzerland and some African countries. At present they are the most likely candidate for taking over 25% of EnBW in Germany.

2. Implementation

France was the last of the European countries to implement the Directive, due to the different views of government and opposition, the opposition having the majority in the Senate.

Only the 1st of February, 2000, the French electricity act was accepted, and published the 10th of February. It provides for an initial opening of 30%, i.e. clients consuming more than 20 GWh per year. The limit will be reduced to 9 GWh in February 2003, opening up 33%.

EdF is the system operator. It has published temporary transmission tariffs on its website.

E. UK/Wales

1. Introduction[36]

In 1989, the Electricity Act laid the legislative foundations for the liberalisation of the electricity market in England and Wales. Privatisation and the introduction of competition needed the creation of a regulator (Offer – Office for Electricity Regulation) with the function of watchdog and an Electricity Pool to ensure an adequate trading and settlement system.

As the convergence of the gas and electricity markets became evident, the electricity and gas regulators (Ofgas) were merged in June 1999 to one common regulator named Ofgem (Office for Gas and Electricity Market).

Recently, the New Electricity Trade Arrangements (NETA) were finalised. A conclusion is presented in June. The introduction of the NETA is expected in autumn 2000.

2. Structure of the Electricity Industry

The Electricity Industry consists of four main activities: generation, transmission, distribution and supply[37].

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[35] Information is taken from [12] to [14], [28] and [41] to [43].

[36] Information is taken form [44] to [55].

Activity	Based on	Company
Generation	Competition	National Power (30%)(1), Powergen (24%)(2), Nuclear Electric(11%), Magnox Electric (4%), First Hydro (3%), Independents (9%)
Transmission	Independent regulation	NGC, National Grid Company
Distribution	Independent regulation	12 REC, Regional Electricity Company
Supply	Competition	12 REC, Regional Electricity Company(3)

(1) Includes 4000MW of plant now leased to Eastern (2) Includes 200MW of plant now leased to Eastern

(3) Supply can be done by any company having a second tier supply licence granted by Ofgem, this can be the REC, generators or other companies not previously selling electricity.

In order to carry out each of these activities, companies need to be licensed by the regulator Ofgem. The interaction between these activities, leading to the wholesale trade of electricity, takes place through the Electricity Pool.

3. *Regulation of the Electricity Industry - Ofgem*

Ofgem must ensure that all reasonable demands for electricity are met, that those providing these services are able to finance their operations and they must promote competition in generation and supply. To meet those objectives, Ofgem disposes of some control mechanisms like the right to grant licences and the imposition of price controls. Furthermore, the companies have to justify their acts to Ofgem.

a) Price Control Mechanism (PCM)

The price control is based on the RPI-X formula, i.e. the average price is not allowed to increase by more than the rate of inflation as measured by the Retail Price Index (RPI) minus a specified level X, set by the regulator. It provides customer protection in a not yet completely developed market, and it gives efficiency incentives.

Activity	PCM	Imposed by
Generation	Competition	Driven by free market process
Transmission	RPI-X	Director General of Ofgem
Distribution	RPI-X	Director General of Ofgem
Supply	RPI-X[38]	Director General of Ofgem

b) Supervision

Two activities, transmission and distribution, must annually report to Ofgem to ensure that they comply with their statutory duties under the Electricity Act and with their licences. All four activities are supervised by Ofgem. Responsibilities of transmission are maintaining an efficient, co-ordinated and economical transmission system, ensuring non-discrimination between users or classes of users, and facilitating competition in the generation and supply of

37 Process of buying electricity in bulk and selling it to customers.

38 Competition is being introduced to all so a review must point out if price control is still necessary to protect customers.

electricity. Distribution responsibilities include system security, availability, and quality of service.

4. *Trade of Electricity – The Electricity Pool*

The wholesale market mechanism through which electricity is traded at present is called the Electricity Pool of England and Wales. Generators offer electricity for sale, which is then pooled to meet suppliers' demand. Participation in the market is through membership of the Pool under the Pooling and Settlement Agreement (PSA).

a) Mechanism

Day ahead

Generators submit by 10AM their day ahead bids into the Pool, defining how much electricity they are willing to generate for every half-hour of the next day and at what price. NGC produces a forecast of demand (plus reserve) for each half hour of the following day and schedules the generators' bids to meet this demand. A computer system, Generating Ordering and Loading (GOAL), aims to produce the lowest cost generation schedule for the day as a whole. This schedule is called the Unconstrained Schedule, as no system constraints, such as congestion, are considered.

Day itself

NGC is responsible for the scheduling and dispatch of generation on the day to meet actual demand, taking into account the possible constraints.

Settlement

Settlement is the mechanism by which payments for the trading of electricity between Pool Members are calculated, usually 28 days after the trading day.

b) Payments

Generators sell power into the Pool at Pool Purchase Price (PPP), while suppliers buy from the Pool at the Pool Selling Price (PSP). These are defined in the following way:

- SMP (System Marginal Price): price of the most expensive generating unit required to meet forecast demand;
- CP (Capacity Payment): incentive to generators to maintain an adequate margin over the level of demand;
- Uplift : used to pay for a number of additional costs incurred at the day;
- PPP (Pool Purchase Price): SMP+CP, the price at which generators sell power in the Pool;
- PSP (Pool Selling Price): PPP + uplift, the price at which suppliers buy from the Pool.

5. NETA

The review process RETA (Reform of Electricity Trading Arrangements) led to the NETA.

This review was introduced because the present arrangements show several disadvantages, such as limited competition in price-setting, limited demand-side participation, complexity of bidding and price-setting, compulsory membership, slow pace of Pool reform, ... The trading arrangements are designed to be more efficient and to provide greater choice for market participants whilst maintaining the operation of a secure and reliable electricity system. The proposals are based on bilateral trading between generators, suppliers, traders and customers. They include:

- Forwards and futures markets (including short-term power exchanges), evolving in response to the requirements of participants, which will allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets.
- A balancing mechanism in which NGC, as System Operator, accepts offers of and bids for electricity, to enable it to balance the system.
- A Settlement Process
    - for charging participants whose contracted positions do not match their metered volumes of electricity,
    - for the settlement of accepted Balancing Mechanism offers and bids,
    - and for recovering the System Operator's costs of balancing the system.

It is envisaged that the present Pooling and Settlement Agreement (PSA) will be replaced by a Balancing and Settlement Code (BSC), incorporating the rules of the Balancing Mechanism and the Settlement Process. NGC, as System Operator, will be obliged to maintain the Code. Licensees will be obliged to conform to it. The Code will include flexible and effective governance arrangements to allow for modifications to the rules.

To achieve the objective of the NETA, Ofgem introduces a market abuse condition (to discourage damaging exploitation of market power) into the licences held by seven generators. Those seven have a market share that form a potential for abuse of substantial market power in a wholesale market. Five (BNFL Magnox, Edison Mission Energy, National Power, PowerGen and TXU Europe) have agreed. The two others (AES and British Energy) did not agree and Ofgem intends to refer them to the Competition Commission.

F. Scandinavian countries

During the 1990s, the Nordic countries Norway, Finland, Sweden and Denmark have gradually created a common market. In 1996 the Nordic Power Exchange, Nord Pool, became the first international commodity exchange in electricity. As the differences between these four countries are important, the Nordic experience can yield some useful insights for the creation of a common European market, consisting of 15 different markets. The information is taken from [56].

1. Norway

Norway deregulated its electricity market in 1991. Statnett was established as a transmission system operator from 1992, and a tariff system (grid access tariffs) was implemented, a prerequisite for the consumers' ability to choose their suppliers freely. Statnett established the power exchange (Statnett Marked) in 1993, at first covering only the Norwegian market, then later leading to a common Norwegian-Swedish market. Accordingly the power exchange changed its name to Nord Pool, and Svenska Kraftnät stepped in as co-owner.

Approximately 200 utilities are competing to supply electricity to Norwegian consumers, who can choose a supplier freely, without charge for changing supplier. There are no requirements as to specific electricity meters for small consumers.

Almost the entire Norwegian electricity production is based on hydropower. Due to low electricity prices and positive macro-economic growth, the electricity consumption has increased steadily throughout the 1990s. Production has, however, not kept pace. As a result, Norway is today a net importer of electricity. There are several plans to build new hydroelectric power and gas power stations, but the proposals have faced considerable political opposition.

2. Sweden

The state-owned Svenska Kraftnät (Swedish national grid) was launched on January 1, 1992, to manage the network and foreign links. This was the first major step toward a liberalised and competitive electricity market, established on January 1, 1996. A new tariff system, with point of access tariffs, was implemented. At the same time Svenska Kraftnät stepped in as co-owner of Nord Pool and a common Norwegian-Swedish market became a reality.

In Sweden six large producers control 94 percent of the total electricity generation and approximately 220 supply companies compete on the market. From November 1, 1999, there are no requirements for specific electricity meters or other extra charges for ordinary consumers. This makes it easier for consumers to freely choose a new supplier.

Electricity consumption doubled in Sweden during the period from 1970 till the mid-1980s. Electricity consumption has increased especially in the domestic and service sectors, but the industrial sector has also contributed. The development of nuclear power has meant that electricity has out-distanced other forms of energy, particularly fossil fuels such as coal and oil. In recent years some of the oil-fired condensing units, kept as a reserve, have been closed.

Sweden has mainly been a net exporter of electricity to date. There seem to be no plans to build new capacity.

3. Finland

The Electricity Market Act and the point of access tariff in 1995 opened the Finnish electricity market for competition. A later modification of the law has since autumn 1998 made it possible for all consumers to choose a supplier freely at no extra charge. Thanks to consumption profiles, no special electricity meters are needed for small consumers.

The grid company, Fingrid, started operations in September 1997. It is a fully unbundled, private company. The company is owned jointly by institutional investors, power producers and the government. The decision-making rules of the company guarantee that none of the parties has a controlling position alone or together with any other partner. In August 1996, the Finnish electricity exchange EL-EX started its operations. Fingrid purchased all shares of EL-EX in 1998 and sold half of them to Svenska Kraftnät. From June 15, 1998, Finland became a price area on the Nord Pool Exchange.

The power generation in Finland is diverse with hydro, nuclear and other thermal power, consisting of both conventional plants and combined heat and power. Thermal power plants use fuels like gas, coal, peat and wood. The proportion of the combined heat and power production is exceptionally high compared with other countries. Another characteristic feature is power generation owned by industrial consumers, covering more than half of these consumers´ demand for electricity. Finland is a net importer of electricity.

4. Denmark

The western part of Denmark (Jutland and Funen) has been a part of the Nordic electricity market since the 1st of July, 1999. It forms an independent price bidding area in the Nordic Power Exchange. It is expected that the rest of Denmark in a year's time will be fully integrated in the Nordic Market in the same way.

In accordance with the Danish Electricity Supply Act, electricity production and trade is commercialised, and the ownership of production and trading companies is organised accordingly. Grid owners and transmission system operators continue to be owned by the consumers and are run as non-profit companies subject to close price control by the public energy inspectorate. According to the law the market was opened for distribution companies and end-users with an annual consumption of 100 GWh in 1998. The limit will be changed in year 2000 initially to 10 GWh and later to 1 GWh. By the end of 2002 all consumers will be able to trade freely.

Danish legislation requires a high priority to be given to renewables. In the government's action plan "Energy 21" it is expected that offshore wind farms with a total production output of 4000 MW will be built before 2030, of which the first five farms, totalling 750 MW, are currently being planned. The interaction with the Nordic electricity market is a prerequisite for the ability to sell large quantities of fluctuating energy.

5. Governmental Control over the Grid

In countries with deregulated electricity markets, the transmission company is organised as a "natural monopoly", the operation and finances of which are subject to strict public control (regulation). This is also the case in the Nordic countries. The tasks of the transmission companies are outlined in legislation, and their activities are based on limited concessions issued by the authorities. The networks are divided into three levels: transmission, regional and local network.

a) Norway

The Norwegian Water Resources and Energy Directorate (NVE) is the regulating authority for transmission activities in Norway. NVE determines the income limits for each company. In 1997 the average profit of the network owners amounted to 8 per cent. The grid owners cannot freely set their prices (tariffs). In addition, NVE undertakes an annual financial review of all network owners. If the tariffs have been too high, the network owners are ordered to reimburse the customers by lower prices in a following year. On the other hand, if the tariffs have been set too low, the network owners may charge the deficit in a following year. In Norway a network owner may also undertake electricity trade and production, but the operation of the network must be kept separate from the business activities that are open to competition. NVE determines the annual efficiency requirements for each individual network owner. Network owners that manage a higher efficiency than requested may keep the gain. Statnett is the transmission system operator in Norway and is responsible for the main grid, the interconnections and a range of important regional transmission networks.

b) Sweden

The main grid is owned and operated by the government-owned Svenska Kraftnät. Independent companies own the underlying networks. Cross subsidising of activities open to competition is prohibited. Network tariffs must be reasonable and based on the network owners' costs. Swedish network owners are not allowed to undertake electricity trade or commercial production. The companies are, however, allowed to cover their own network losses with production in their own facilities. Since January 1, 1998, "Nätmyndigheten" under The Swedish National Energy Administration has been the regulating authority for network companies. This body checks company tariffs and annual reports. The aim is to force the most expensive companies to reduce their price. Nätmyndigheten has the power to intervene directly and demand lower prices. A decision to do so may be brought before the administrative tribunal.

c) Finland

The Electricity Market Authority began its work as a regulator in June 1995 as a consequence of the Electricity Market Act. The Authority´s principal task is to promote the efficient functioning of the electricity market and to control transmission and distribution prices. Fingrid owns and operates the main network and the interconnections to Norway, Sweden and Russia. The local distribution companies are in charge of the operation of the regional and local networks. According to legislation, transmission and distribution prices must be reasonable and non-discriminatory. The network companies must keep separate accounts for both electricity trade and transmission. It is prohibited to cross-subsidise activities open to competition. The Authority grants licences to network operators and construction permits for transmission lines for 110 kV and above. The Ministry of Trade and Industry gives permission for new interconnections.

d) Denmark

In accordance with the energy act, network owners and the transmission system operators are run on a non-profit basis. The network owners are only allowed to engage in network activities. If they also wish to trade electricity, they must establish separate commercial trading companies and/or "companies with an obligation to supply". Many network owners are co-owners of power stations as well. Any financial return from these stations must only be used for activities related to the grid owner, such as construction work, electricity saving activities, etc. The two transmission system operators in Denmark (Eltra in the western part and Elkraft System in the eastern part) own and operate the main network (400 kV and the interconnections), and are responsible for all transmission lines above 100 kV. The Government is going to have two representatives on the company boards. Their budgets and tariffs must be approved by the independent public energy control, assessing the efficiency of the companies by means of benchmarking, price caps, etc. All network owners operate on the basis of governmental concessions.

6. Nord Pool (1998)

Players: about 250; Total trade: 145 TWh; Value: about 2.5 billion Euro

	Norway	Sweden	Finland	Denmark	Nordel
Area: [square kilometres]	324 000	450 000	338 000	43 000	1 155 000
Population: [million]	4.4	8.9	5.1	5.3	23.7
Consumption: [TWh], 1998	120	144	76	35	375
Generation: [TWh], 1998	117	154	67	39	377
Hydro power: [%]	99	48	22		54
Nuclear power: [%]		46	31		24
Thermal power: [%]	1	6	47	93	21
Renewables (wind): [%]				7	1
Max load : [GW], 1998					60
Total imports: [GWh], 1998	8.1	6.1	10.2	3.5	27.9
Total exports: [GWh], 1998	4.4	16.9	0.9	7.8	30

Table III.6 Main data on Scandinavian market [56]

IV. TRADING AND PRICE SETTING

This chapter gives a short description of the new market structures for electricity trade that emerge around the world. It concentrates on the short run dynamics of the electricity market. Thus, long run issues such as new investment in generation or transmission capacity are nor discussed. The aim is not to explain in detail how the different markets are organised, but to highlight some major differences. The framework is given in which the different markets can be situated, but not all particularities of the electricity market are captured.[39]

Part I deals with the 'physical' market for the delivery of the commodity 'electricity'. Starting with a simple market model, some problems specific for the use of the grid are introduced. Splitting up the electricity-market into two sub-markets can solve these problems. The second part deals with the financial instruments supporting the 'physical' market transactions. These financial instruments are used to manage the risk of the firms.

A. PART I: THE PHYSICAL MARKET

1. A Simple Market

a) Demand and supply of Electricity

Liberalisation is intended to create a market for electricity. As a first approximation the market for electricity does not differ fundamentally from a market for other goods. On one side of the market the producers generate electricity. On the other side we find consumers consuming electricity.

Demand is the expression of the willingness to pay of consumers. This willingness to pay (WTP) reflects how much he is prepared to pay for an extra kWh of electricity. This is represented in figure IV.1.

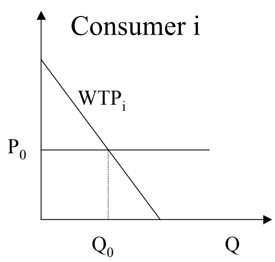

Figure IV.1 Willingness to pay (WTP) of a consumer

His WTP is downward sloping and depends, among other things, on the kWh of electricity Q he has already bought. When a consumer has not yet bought any electricity (Q=0), his WTP is high. He could for example use this electricity to light his house. When he has already bought a lot of electricity, his WTP for an extra kWh of electricity is smaller. The consumer values an

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[39] References for this chapter are [57] to [64].

extra kWh of electricity less: maybe he can spend his money better on another good he needs more.

Which quantity will a consumer buy for a price P_0? The consumer buys electricity until his WTP equals the price P_0. At this point he buys the quantity Q_0, and he is indifferent between buying and not buying an extra amount of electricity.

Market demand is the aggregation of demand of all consumers in the market. Demand for electricity for a certain price is the sum of all individual demands for this price. Graphically all demand functions are added up horizontally (see figure IV.2).

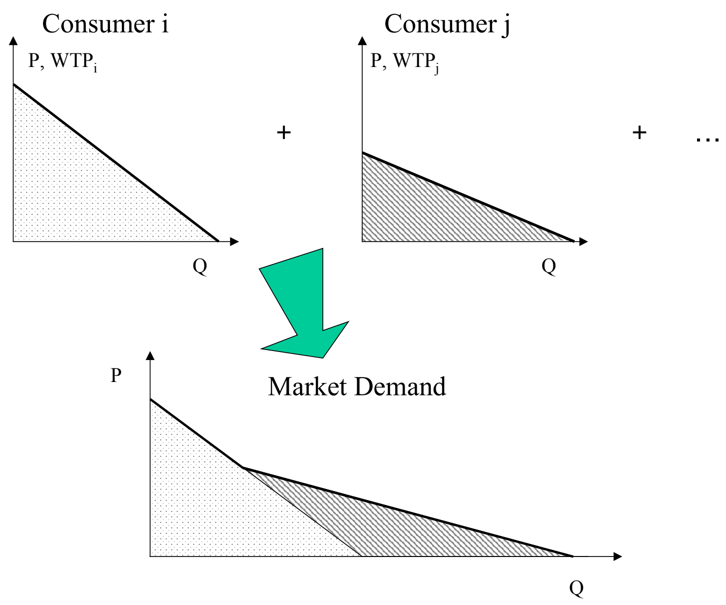

Figure IV.2 Aggregation of individual demand of consumers i and j

In analogy to the theory for the demand for electricity, a theory can be derived for the supply. The marginal cost (MC) of a plant is the cost to produce an extra quantity of electricity. A firm is willing to generate electricity as long as the price it gets is higher than the MC. We assume that for each plant the marginal cost is constant, until maximal capacity is reached[40]. It is impossible for a plant to produce more than this maximal capacity.

The market supply function is the 'horizontal' sum of the supply function of all plants (see figure IV.3). The resulting supply-curve of the electricity market has a staircase shape.

The supply-curve and the demand-curve represent the reaction of respectively the generators and the consumers to prices (see figure IV.4) For simplicity a straight line represents the demand-curve. Each step of the supply-curve represents a plant working at constant MC.

The price P for which demand equals supply is called the *equilibrium price*, or the *market-clearing price*. Market equilibrium will determine which plants are generating. In the equilibrium sketched in figure IV.4 all base-load generators and some of the middle-load generators generate electricity.

[40] By using this assumption, the supply curve we get is the 'merit-order' curve, well known by power engineers.

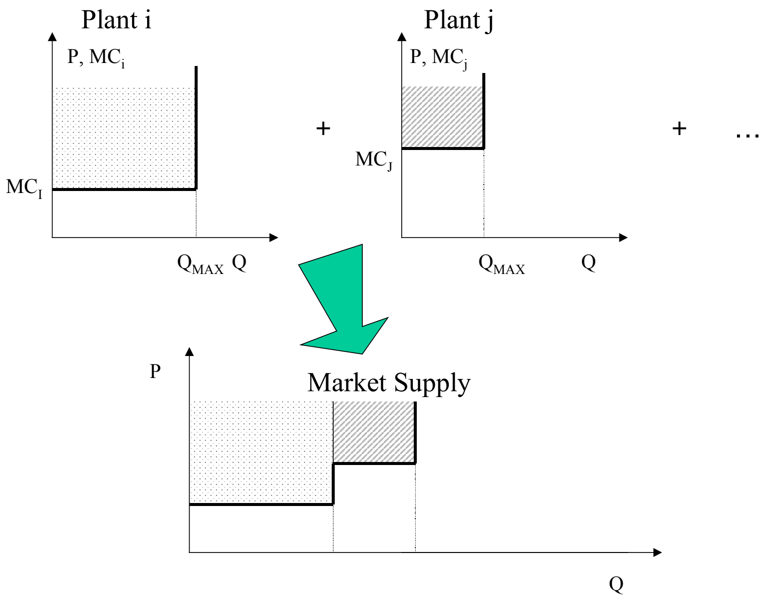

Figure IV.3 Aggregation of supply

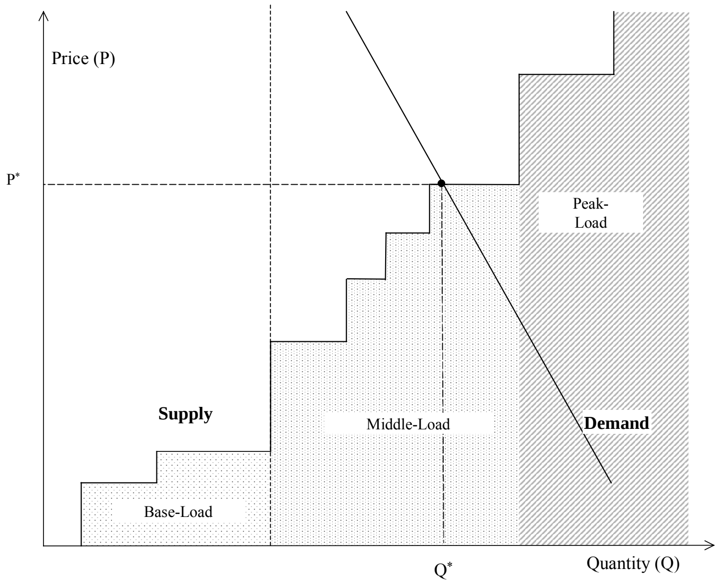

Figure IV.4 Typical demand-curve and supply-curve in the electricity market

Before liberalisation, the provision of electricity was regulated for a long-time. The regulator fixed the price for which the generators had to provide all electricity that was demanded. This price was set in such a way that generators could recover their costs. Consumers were price-takers and consumed for this price the amount they preferred (see figure IV.5). In this case we can not speak about a supply curve of electricity, and can only represent consumers responding to price changes.

b) Shifts in Supply and Demand

Market factors define the price and the amount of electricity generated. Changed market factors will create a new price P^* and a new quantity Q^*. Individual producers and individual consumers do not control all of these market factors, but their profits depend upon this price P^* and the quantity Q^*. Therefore, it is necessary to understand how market factors work.

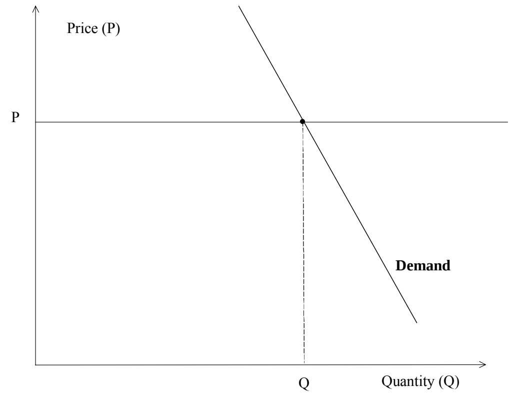

Figure IV.5 Regulated market

Production Cost

The price of the fuel used to generate electricity is an important market factor[41]. When the price of fuel increases, the supply-curve shifts up, and a higher equilibrium price will emerge. Increased fuel prices thus lead to higher electricity prices.

Some countries use hydro-energy to generate electricity. In this case, the fuel price depends on the amount of water available, i.e. the amount of rain that falls in a certain month or year. In Norway for example electricity prices go down when it starts snowing.

Not all fuel prices will have the same impact on the price level. The electricity price that clears the market will depend on the production costs of those plants that will be used to meet an extra demand of electricity. These plants are said to operate 'on the margin'.

An example will make this clear. Suppose that the fuel price of base-load plants increases (see figure IV.6), thereby shifting up a part of the supply curve. This shift will not influence the market-clearing price P^* in the peak period nor the quantity of electricity consumed Q^* in the peak period.

Nuclear plants are mainly used for base-level production; as a consequence the price of nuclear fuel will be a less important price-determining factor for the peak demand price.

Demand Uncertainty

The demand for electricity clearly also has an impact on the equilibrium outcome. When demand grows, the demand curve will shift to the right (see figure IV.7). The intersection of the demand curve and the supply curve will move upwards: the market clearing price P increases. Other things kept constant, colder weather or an important soccer game lead to increased demand for electricity and thus a higher price level.

[41] Fuel-price is used here as a proxy for production costs in general.

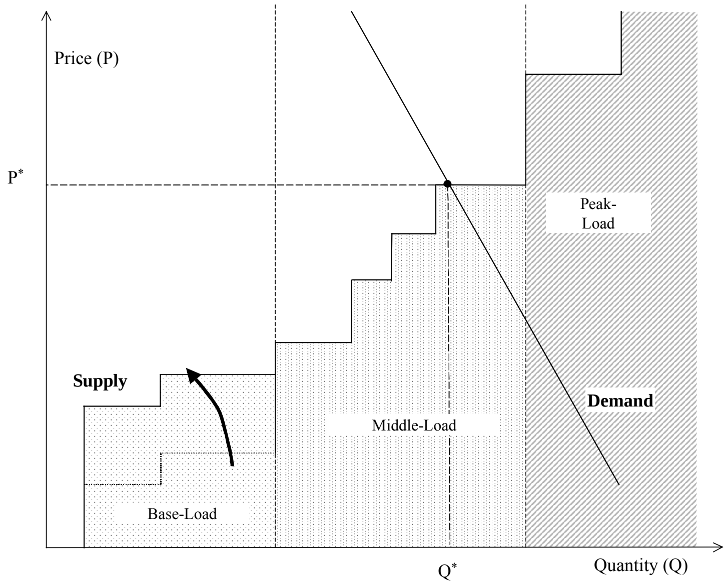

Figure IV.6 Effect of increasing production cost
on the market equilibrium of electricity in the peak period

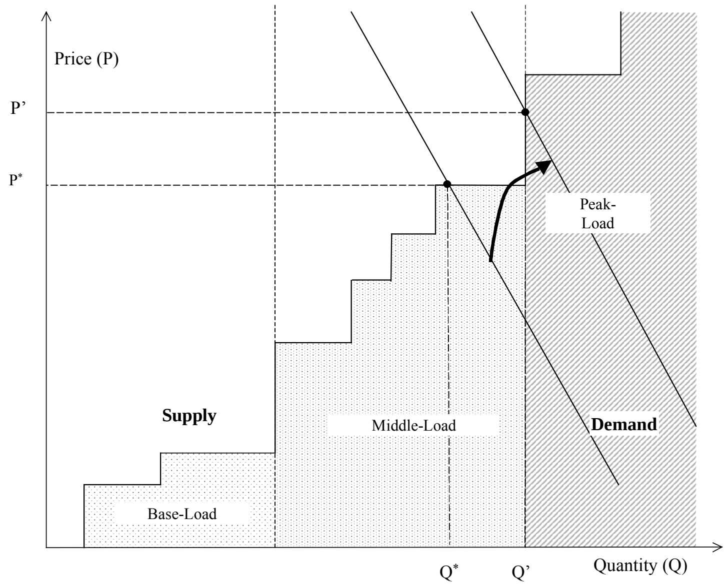

Figure IV.7 Effect of an increase in demand on the market equilibrium

Generation failure

Not all generators will be constantly available. Generators can be in repair or could break down.

When fewer generators are available, the supply-curve shifts to the left. Generators with a higher cost operate at the margin and as a result price goes up.

2. *The Electricity Market in Practice*

a) Two Problems

In the last section we treated electricity as a good that can be traded like any other good. This was not completely correct. In the electricity market some problems arise:

- A first problem is that the demand and the supply of electricity have to match, for each second. Market factors can not respond that fast to changing electricity flows. This problem is called the *balancing problem*.
- A second problem is that grid constraints can reduce the possible trades. Some of these problems can be foreseen, but others happen unexpectedly. This problem is called the *constraints problem*.

In practice, the electricity market is therefore split up or *unbundled* into different markets: *the energy market* and *the regulating market*. Two different ways exist to 'split' the electricity market. To make the distinction, we will call them type I and type II markets.

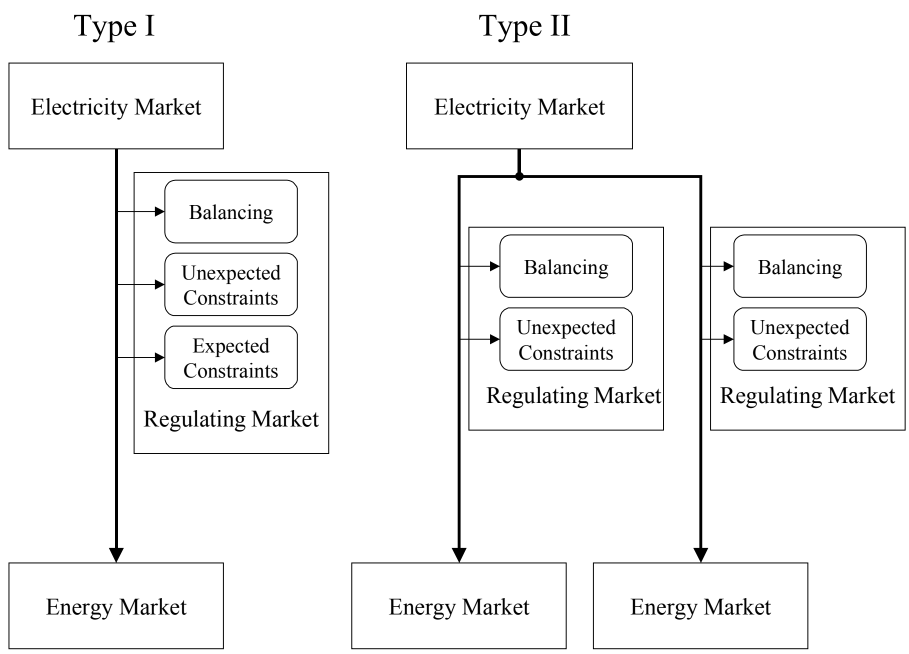

Figure IV.8 Difference between type I and type II markets

In a type I market all problems of the electricity market are transferred to the *regulating market*. To indicate the difference we call the electricity market without these problems the *energy market*. As all problems disappeared, the energy market is a rather simple market where market factors will decide about the outcome as before. See in figure IV.8 the scheme on the left.

When the system operator expects some constraints a type II market is geographically divided into smaller regions in which no constraints are expected. For each of these regions an energy market and a regulating market is established. See the scheme at the right.

The energy markets are again very simple markets[42]. A prerequisite for type II markets is that it is possible to recognise different regions connected with relatively few connections.

The advantage of a type I market is that there are many producers and generators in the energy market, which could increase competition between the different generators. Splitting up the market could for example increase the market power of certain generators. The advantage of a type II market is that congestion costs are resolved by a market mechanism.

To deal with the special aspects of the electricity market a *system operator* is appointed. The system operator is responsible for the reliability of the grid. He has to provide extra services, called *ancillary services,* which are needed for the grid security and power quality. As part of the provision of ancillary services the system operator closely manages the regulating market. The system operator operates this market in real time, i.e. decisions are taken and executed immediately. Contracts on the regulating market are always contracts between the regulator on one side and a consumer or a generator on the other side.

Contracts on the energy market are concluded between consumers and generators. They should make contracts a certain time before physical delivery will take place[43]. After this moment additional contracts are no longer 'valid'[44].

Figure IV.9 shows graphically how the electricity market is split up in the energy market and the regulating market.

b) The energy Market

Two ways to organise transactions

Transactions in the energy market can be organised with bilateral contracts and pool contracts.

Pools[45] are organised, anonymous markets for electricity. This kind of market closely mimics the market mechanism explained in figure IV.4. Typically, market players make bids in a standardised format, usually one day in advance of production. Market clearing takes place for short time intervals (half-hour or one hour). The market-clearing price P_{spot} of the pool is called the spot price. All electricity in the pool is traded at this spot price P_{spot}.

The pool is usually co-ordinated by an institution that works in close co-ordination with the system operator, but it is not necessary that the system operator himself runs it.

With a *bilateral contract* two market players enter into a contract for the delivery of electricity. Usually, these contracts are long-run contracts, for example for the delivery of electricity for a full year.

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[42] An example of a type I market is the system in England and Wales. The Nordic countries have a type II market. There, the electricity market is divided into smaller regions when constraints are expected to last for at least three consequent days.

The distinction between a type I and type II market is not always that clear. Most markets have a mixed type. The electricity market of mainland Europe can be seen as one big type II market. Belgium, seen as one entity, has a type I market.

[43] Most common this is just one day before. Therefore, it is usually called the day ahead market

[44] Often, contracts between generators and consumers can be concluded up to one day before actual delivery. Therefore, this market is called the day ahead market.

[45] Sometimes Pools are also called power exchanges, electricity spot-markets.

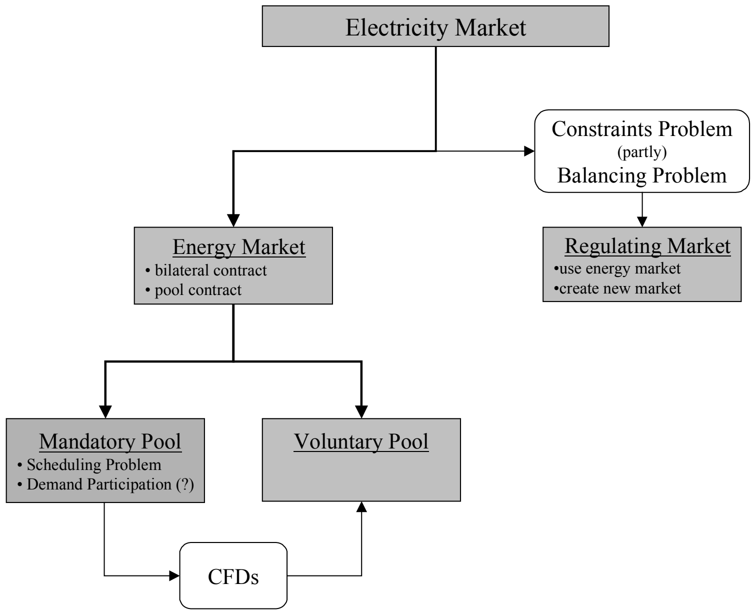

Figure IV.9 Structure of the Electricity Market

The big advantage of a pool is that the anonymity of the markets keeps transaction costs low. With bilateral contracts it is costly to switch from one generator to another.

Bilateral contracts have the advantage that they provide higher price stability. Once electricity is contracted you know the price of electricity for the next year. In a Pool system you do not know the price at the moment you supply the bid. Only after bidding closure in the Pool will the clearing price be known.

Not all countries allow the use of bilateral contracts. Some countries oblige market participants to trade through a *mandatory pool*. Other countries leave both possibilities open. They created a *voluntary pool*[46]. We will discuss these two forms in the next sub-sections.

Mandatory pool

In a *mandatory pool* all electricity must be traded through the central spot market. Bilateral contracts for the delivery of electricity are not allowed. The system operator itself manages the pool.

In a mandatory pool the firm does not decide upon running or not running a plant. This decision is completely determined by the market outcome. Firms face the risk that they will not be scheduled. This is called the *scheduling problem.*

It is perfectly possible that, when markets are cleared for every hour or every half-hour, a certain plant has to run for only half an hour during a specific day. For a coal plant it takes eight hours before it is on temperature and can supply electricity. It is clear that switching on a

[46] Some authors use ‘pool’ to indicate the mandatory pool; and use ‘exchange’ for the voluntary pool.

coal plant for half an hour will not be an efficient outcome[47]. In most mandatory pools price bids are therefore not simple price bids as in our simple example in the first section above.

Bids can include start up costs, non-running cost, start-up time etc. To determine the actual price level and generation quantity the system operator will solve a complex optimisation problem. Generators will not simply get the market clearing price for their generated capacity but also a refund for start-up cost, non-running costs etc.

The physical dispatch strongly depends on the solution algorithm that solves the optimisation problem. Plants may be excluded even if they would be willing to be dispatched at going pool prices.

Repeated bidding of the generators could partly solve some of these problems As far as we know this is not yet used in practice.

Not all mandatory pools let consumers bid on the pool. In some pools the system operator makes a prediction of demand. The demand-curve in figure IV.4 will then be replaced by a predicted demand-curve of the system operator. This predicted demand curve usually is assumed to be vertical. Consumers are thus expected not to respond to price-signals.

This decision is motivated by the fact that most final consumers are not exposed to short-term price movements and will not change their consumption to changing prices. Only large energy-intensive industries are actively managing their load profile in response to the electricity price.

One objection can be made against the exclusion of demand side bidding. Consumers are better suited to make a prediction of their consumption than the System Operator. Demand predictions are less accurate when the System Operator makes them[48]. Including demand side bidding could increase the efficiency of the market.

Examples of mandatory pools can be found in England & Wales, Australia (National market) and California (mandatory for investor owned utilities in a transitional phase)[49].

Voluntary Pool

In a *Voluntary Pool* generators and purchasers are free to trade either through the pool on a short-term basis as in a mandatory pool or through long-term bilateral contracts. Usually, the manager of the pool is a private organisation working in co-operation with the system operator. In some countries there is no interest to establish a pool and only bilateral market contracts exist.

In a voluntary pool prices are mostly simple price bids; they will not include start-up costs, non-running costs etc. These simple price bids are easier to understand than the bids made in most mandatory pools.

As generators can conclude bilateral contracts, they decide themselves on scheduling.

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[47] On the contrary, when a coal plant is scheduled to run several times a day, it can be kept in hot stand-by.

[48] In England and Wales consumers were originally not allowed to bid in the electricity pool. Nowadays some big consumers are treated as generators. They are assumed to produce electricity by decreasing their consumption of electricity.

[49] See www.calpx.com or www.elecpool.com

Generators are not paid explicitly for their start-up costs, non-running costs etc. They have to cover these costs with the prices they charge in their contracts. These costs depend on the specific scheduling of the plants. Internalising these costs is easier when these costs are very small, as for example for hydropower plants. Such hydropower plants can without problem contract all electricity over the pool. Big coal plant producers have more problems to contract all of their electricity through the pool. They could be obliged to schedule their plants in a very costly way, when they have to follow the contracts they concluded on the exchange.

In the electricity market some of the generators are usually dominant. In a voluntary pool system it is in theory possible that generators differentiate prices between different consumers.

Examples of voluntary pool systems can be found in the Netherlands or in the Nordic countries[50].

Contracts for Differences.

By using *Contracts for Differences* (CFDs) companies can mimic a bilateral contract in an obligatory pool. A CFD is a contract where the generator will receive a price P_{CFD} agreed upon in advance minus the spot price P from the consumer. From the pool he will receive the spot price P.

Generators receive net the P_{CFD} price for their generation, and consumers pay net the P_{CFD} price.

Net result for the generator

	P	Received through Pool
+	$P_{CFD} - P$	Received of consumer for CFD
=	P_{CFD}	Net received by Generator

Net result for the consumer

	P	Paid through Pool
+	$P_{CFD} - P$	Paid through generator for CFD
=	P_{CFD}	Net paid by Generator

Table IV.1 Net result of CFDs for generators and consumers

By concluding a CFD the price uncertainty in a mandatory pool is resolved. Generators and consumers know which price they will receive or have to pay.

The scheduling problem remains. The system operator still decides the scheduling based upon the bids of the market players. In theory, generators could solve their scheduling problem by bidding a very low price, making sure that the system operator will schedule them.

CFDs convert mandatory pools in voluntary pools. They make the functioning of mandatory pools less transparent. Most countries therefore will restrict the use of CFDs. Some authors blame CFDs for creating market distortions, in the sense that some market players can more easily abuse their market power.

[50] See http://www.apx.nl/ and http://www.nordpool.no

c) The Regulating Market

On the energy market pool-contracts and bilateral contracts are concluded between the different market participants. The *net contracted position* of a market player is the sum of all supply obligations minus the sum of all demand obligations. A generator typically will have a positive contracted net position and a consumer will have typically a negative contracted net position.

When the energy market closes the net contracted position of all participants is given to the system operator. The system operator must enable the fulfilment of these contracts.

As mentioned before, in reality there will always be a difference between the contracted and the actual quantities for two main reasons:

- Technical constraints bind the execution of contracts. This problem was called the *Constraints Problem;*
- Imperfect prediction of contracted and actual quantities, the so-called *Balancing Problem.*

The system operator has to solve these two problems. Some of the generators and consumers are able to change their quantities in a controllable way[51]. The System Operator will ask these generators or consumers to change their quantities consumed or produced. This is called the supply of regulating power by the generators and consumers to the system operator.

The regulating market is that market where the system operator buys this regulating power. This market is different from the energy market, where consumers and generators concluded contracts with each other. In the regulating market, we have on one side of the market the system operator who demands regulating power, and on the other side the controllable generators and consumers supplying it. Buying the right amount of regulating power, the system operator solves the constraints problem and the balancing problem.

Two different kinds of regulating power exist. The system operator buys *down-regulation* when supply is too high and *up-regulation* when supply is too low. Generators can provide down-regulation by reducing their generation, and consumers by increasing their consumption. An increased generation or a decreased consumption provides up-regulation.

How the system operator covers his expenses for regulating power depends on the kind of problem he has to solve.

- When regulating power is used to solve the constraint problem, the cost is covered by the transmission tariff.
- When regulating power is used to solve the balancing problem the responsible market players are penalised. Generators and consumers that deviate from their contracted position will pay a penalty to the system operator.

The regulating market can be organised in three different ways:

1. The system operator concludes *long-term contracts* with certain market players to provide regulating power. This kind of organisation is often used when there is no pool.

[51] They must be able to change their quantities satisfactory fast.

2. An exchange for regulating power is established. Generators and consumers supply bids for the delivery of regulating power. The system operator buys the cheapest bids. This kind of organisation is often used in a voluntary pool.
3. The bids of the generators and the consumers in the energy market are re-used in the regulating market. This kind of organisation is often used in combination with a mandatory pool.

B. PART II: FINANCIAL MARKETS.

From the previous part we remember that the price defined on the spot market is influenced by unpredictable market factors. As the market forces are not known in advance, the spot price is unpredictable and market participants face uncertainty. Using a very simple example we will show the difference between a cash contract, a forward contract and a futures contract.

1. Uncertainty

Example

The situation in the Middle East is uncertain. When Iraq and the UN come to an agreement, the restriction of oil exports will be lifted. On the other hand it is also possible that the US will once more attack Iraq. But the situation could also remain unchanged.

These different scenarios are called ‘states of the world’. We assume that, although the future outcome is unknown, we can assign probabilities to the different states (see Table IV.2). In reality, an infinite number of such states exist, here we only consider three of them.

‘State of the world’	Probability of this state	Spot Price Electricity Market
(A) Ban on Iraquian oil export is lifted.	1/6	0.8
(B) Nothing special happens	2/3	1.0
(C) War in Middle East started	1/6	1.2

Table IV.2 Different outcomes

In each state a different fuel price will prevail. As these fuel prices are important market factors, the electricity spot price changes too[52].

The *expected price* is the price a consumer would pay on average over the possibilities in Table IV.2. The *expected price* on the 1st of January, 2001, equals the sum over all states of the prices weighted with their probability. In our case the expected price equals 1.

[52] We do not specify units in this text. Arbitrary units can be assigned to the prices and quantities.

2. *Influence of uncertainty for Market Participants.*

The cash flow of a contract is the monetary flow it generates. A contract involving a net receipt of money has a positive cash flow and a contract involving a payment has a negative net cash flow[53].

Suppose that a generator and a consumer agree on the delivery of electricity on the 1st of January, 2001, *against spot price*. The 1st of January, 2001, is called the delivery-date.

Because the contract is linked to the spot price it is called a *cash contract.* As a result the cash flows of consumer and generator depend on the future spot price[54]. See Table IV.3. It is obvious that the cash flow of the generator and the consumer sum up to zero as they represent one transaction.

A firm that hopes for an increasing spot price is *going long*, and a firm that hopes for a decreasing spot price is *going short*[55]. In a cash contract the consumer and the generator are respectively going short and going long.

		Cash Flow	
		Generator	**Consumer**
State	Spot Price	Going Long	Going Short
(A)	0.8	+0.8	-0.8
(B)	1.0	+1.0	-1.0
(C)	1.2	+1.2	-1.2

Table IV.3 Cash flow of a cash contract

The consumer and the generator are uncertain about their future cash flow, as it is not known in advance which state of the world will prevail. The expected cash flow of the generator is +1.0 and of the consumer –1.0.

In the real world the spot price can be any positive number, not just three discrete numbers as in our example. Figure IV.10 generalises the information of Table IV.3, representing the cash flow of the generator and the consumer.

3. *Buying a Forward Contract.*

Suppose that our two firms decide today to deliver 1 unit of electricity on the 1st of January, 2001, for a price they already decided on today. At the delivery-date the generator has to generate the electricity for the consumer and the consumer will have to pay the price already agreed upon today. This kind of bilateral contract is called a *forward contract*. It specifies *a fixed price* for a certain transaction in the future.

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53 Money today has a different value than money in the future. To compare values in the future with values today we should convert the values to the same point of time using the interest rate. In this text we use the 1st of January, 2001, as the reference point of time.

54 We will continue to use the assumptions of Table IV.2 for the rest of the text.

55 More formally a firm is called ‘to go short’ when his cash flow decreases with increasing spot price. On the other hand, when the cash flow increases with increasing spot prices, a firm is going long.

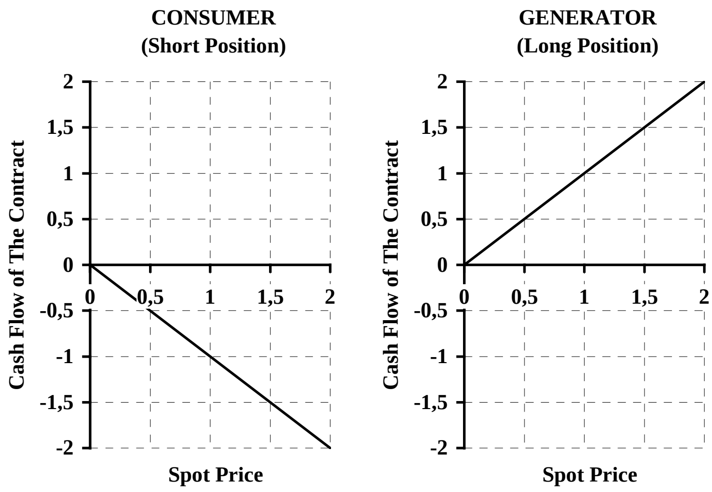

Figure IV.10 Cash Flow of a cash contract

The law of demand and supply determines this fixed forward price. Because the forward price adapts until the demand equals supply, nobody pays for the contract at the moment of signing, i.e. the market value of a forward contract is zero at the moment of signing. Although the fixed forward price is not necessarily equal to the expected spot price of 1.0 we assume that it does so in order to simplify the problem[56].

With a forward contract there exists no longer uncertainty about the cash flows of the contract, as can be seen in Table IV.4 and, for the more general case, in figure IV.11.

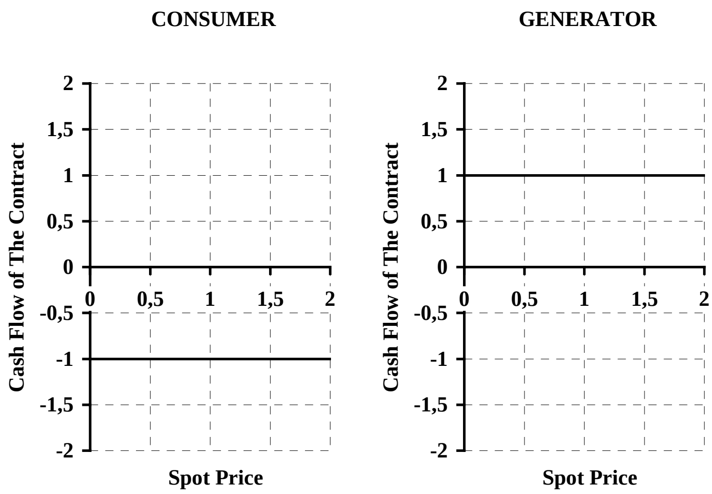

Figure IV.11 Cash Flow of a forward contract

[56] In the case that there is no systematic risk in the electricity market, the forward price equals the expected price. Systematic risk, like a war or an international crisis, is risk that affects the world as a whole.

The underlying reason for this is quite technical: An insurance against systematic risk needs a premium payment. To insure a non-systematic risk a firm does not need to pay a premium because non-systematic risk can be traded away by holding a good diversified portfolio.

State	Spot Price	Cash Flow	
		Generator	Consumer
(A)	0.8	+1.0	-1.0
(B)	1.0	+1.0	-1.0
(C)	1.2	+1.0	-1.0

Table IV.4 Cash flow of the Forward Contract

a) Value of a forward contract.

Although the contract does not have a market value when signed, it can have a market value on delivery-date. In state (A), when the spot price is equal to the price 0.8, a consumer will have the impression of making a loss. Instead of buying electricity at 0.8, he has to buy electricity at a price of 1.0. The value of the contract in this state of the world equals –0.2. As before the generator has the position opposite to the consumer. See Table IV.5 and, for the more general case, figure IV.12.

State	Spot Price	Generator		Consumer	
		Cash Flow	Value	Cash Flow	Value
(A)	0.8	+1.0	+0.2	-1.0	-0.2
(B)	1.0	+1.0	+0.0	-1.0	-0.0
(C)	1.2	+1.0	-0.2	-1.0	+0.2

Table IV.5 Value of a forward contract for a consumer

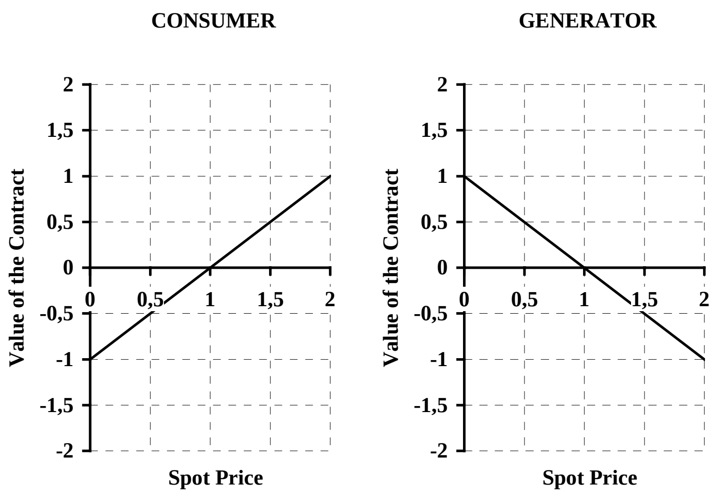

Figure IV.12 Value of a forward contract against spot price

In state (A), signing the contract did give rise to 'a loss' for the consumer, but we should not judge the strategy of signing the forward ex-post, but ex-ante taking into account uncertainty. Let us compare the two strategies:

- Sign a cash contract (delivery at spot price);
- Sign a forward contract (delivery at fixed price).

We compare these contracts on the basis of the cash flow they generate in the different states. Putting the information for the consumer of Table IV.3 and Table IV.4 together gives us Table IV.6.

State	Spot Price	Cash Flow Strategy I Cash-Contract	 Strategy II Forward Contract
(A)	0.8	-0.8	-1.0
(B)	1.0	-1.0	-1.0
(C)	1.2	-1.2	-1.0
Expected Cash flow		-1.0	-1.0
Uncertainty of Cash Flow		Big	No

Table IV.6 Comparing Strategy I and Strategy II for a consumer

Using the information in this table we can compute the expected cash flow and the uncertainty of both strategies. The expected cash flow is equal in both strategies, but the uncertainty is higher in the first strategy. Making a similar comparison for the generator leads to the same results: signing the forward contract reduces the uncertainty of the cash flows. A forward contract can be seen as an instrument to insure the companies against price fluctuations on the cash market[57].

4. *Futures Contract.*

a) Introduction

Suppose that the spot price on the 1st of January is equal to 1.2, and concentrate on the case for the consumer. At delivery date, the consumer has to pay the generator the forward price 1.0 and receives one unit of electricity. See the left-most diagram in figure IV.13.

Instead of generating the electricity, the generator could also buy the electricity at the spot price (see the diagram in the middle). For the consumer this makes no difference.

But the generator could also pay the consumer the spot price, so that the consumer can buy electricity on the spot market himself. The generator pays net 0.2 and the consumer will receive 0.2. See the right-most diagram.

When a contract is cleared by actual delivery the contract is cleared *physically*. When a financial refund clears the contract, the contract is *cleared financially*. Future contracts are forward contracts that are cleared financially. Figure IV.13 shows that the consumer can replace a forward contract with a futures contract and a cash contract.

[57] The strategies described here are the *long hedge* (for the consumer) and the *short hedge* (for the generator). Not only generators and consumers, but also traders, who buy and resell electricity, and speculators, who add liquidity to the market, participate in the financial markets. More complicated strategies than the long and the short hedge are used.

In the next subsection we discuss this into more detail. We define a futures contract and will show how the combination of such a futures contract with a cash contract generates the same cash flow as a forward contract[58].

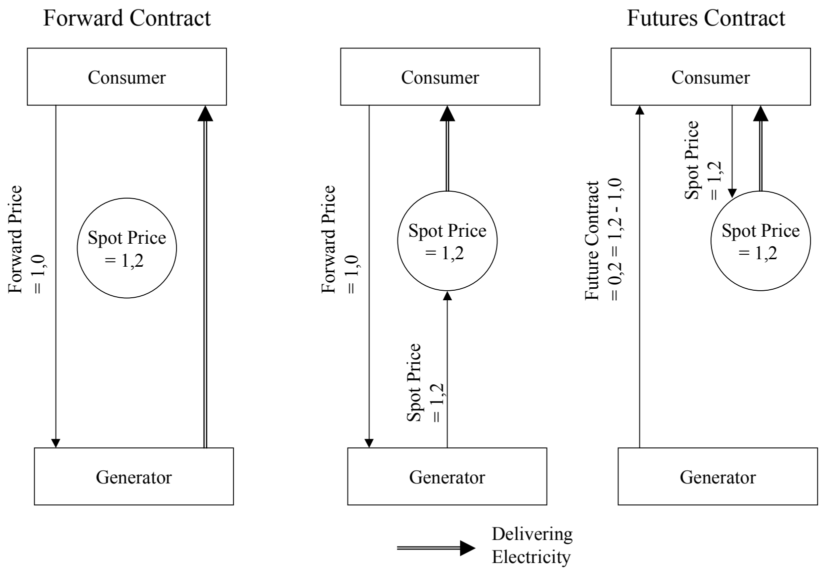

Figure IV.13 From forward to futures contracts

b) Definition and Use

As mentioned before, a forward contract is a contract insuring against changes in the spot price. The insurance is paid out physically by the delivery of electricity. Most insurance contracts do not refund physically. A car insurance for example gives a financial refund instead of a car of the same age, the same colour etc… If we simply want to insure a fixed price the whole process of delivering, metering, etc. is quite cumbersome, and a financial refund would be far more flexible.

The size of the refund should be equal to the loss. The loss incurred by the consumer is equal to the forward price minus the spot price on delivery date. In the case the spot price increases to 1.2 the consumer receives a payment of 0.2.

Formally, we define the futures contract by the cash flows it generates in the different states. Within a futures contract, no physical good is exchanged. It is common to define the seller and the buyer of the futures contract as in Table IV.7[59]. Instead of using the words ‘seller’ and ‘buyer’ often the terms ‘going long’ and ‘going short’ are used. The dashed line in figure IV.14 represents the cash flows of the futures contract in the continuous case. The expected cash flow of the futures contract is zero for both the seller and the buyer.

---

[58] Other financial instruments than the standard forward and futures contracts are used. (1) Some exchanges trade for example option contracts. (For a discussion see NR HULL-51). (2) The specification of forward contracts is often tailored to the specific needs of the signers. e.g. forward contracts often do not specify a fixed price, but a price indexed on the fuel price.

[59] Because no goods are exchanged between the two signing parties, it is not obvious to speak about a seller and a buyer. There is a trade from one state of the world to another.

			Cash Flow	
			Generator	**Consumer**
State	Prob.	Spot Price	Seller of the Contract Short Position	Buyer of the Contract Long Position
(A)	1/6	0.8	+0.2	-0.2
(B)	2/3	1.0	+0.0	-0.0
(C)	1/6	1.2	-0.0	+0.2
Expected Cash Flow			+0.0	+0.0

Table IV.7 Definition of the futures contract

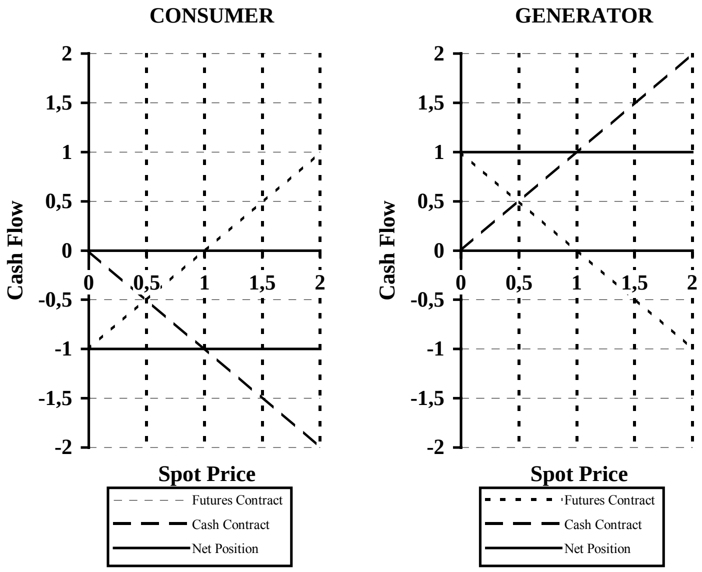

Figure IV.14 Net cash flow of consumer and generator

In the new strategy the consumer has two contracts: on one hand he has a cash contract for the delivery of electricity at the spot price, and on the other hand a futures contract insuring him against unexpected price changes. Table IV.8 represents this new strategy and 'proves' that this strategy has the same net cash flow as a forward contract. The cash flows of the insurance contract and the cash contract change in contrary directions, cancelling out the uncertainty.

		Cash Flow		
State	Spot Price	Cash Contract Going Short	Futures Contract Going Long	Net
(A)	0.8	-0.8	-0.2	-1.0
(B)	1.0	-1.0	-0.0	-1.0
(C)	1.2	-1.2	+0.2	-1.0
Expected Cash Flow		-1.0	+0.0	-1.0
Uncertainty of Cash Flow		Big	Big	No

Table IV.8 Strategy of a consumer

Look, for example, to the third row where the spot price equals 1.2. In this case the consumer has to pay 1.2 for his cash contract (third column), and receives 0.2 from his insurance contract. His net cash flow is –1.0.

As before we represent this information for continuous spot prices. Figure IV.14 shows the cash flow of the cash contract and the futures contract together with the net cash flow.

In general, a financial instrument[60] requires only a small initial capital, but can generate a large cash flow. This makes it appropriate to manage risk. On the other hand, when imprudently used, it can increase the risk of a firm, and cause large losses.[61]

c) Trading

Futures contracts are *anonymously traded on the exchange*[62]. The exchange is the middleman between sellers and buyers. To enhance trade the contracts have to be standardized. These standards deal with delivery-date, the amount of electricity sold, etc…

As a result, market participants can trade their risk actively. They can close out, or 'neutralise' a certain futures contract by entering a futures contract for an opposite transaction[63]. A market participant, for example, who bought a futures contract can compensate it by selling a similar contract[64].

Because the seller and the buyer of the futures contract do not know each other they can not judge if the counter party in the contract is solvent. Therefore, the exchange asks the market participants to give a pledge to the exchange. When the buyer or seller can not fulfil his duties, the exchange will indemnify, and take care of the delivery of the money.

In the case of forward contracts, the market participants bear the risk that the counter party of the contract will not fulfil his obligations. Because no pledge has to be paid, forward contracts are less expensive than futures contracts.

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60 A Futures contract requires no payment in advance; an option contract requires a small payment.

61 In the summer of 1998, electricity prices rose to 7000 USD/MWh due to the inappropriate use of futures contracts by electricity traders. In the broader market, Procter and Gamble, and Barings, suffered in the early 1990s some huge losses by using financial instruments.

62 CFDs, covered in the first part, are strictly speaking non-tradable futures contracts. The term CFDs is mostly reserved for a mandatory pool.

63 Because both consumers and generators can buy and sell contracts, Table IV.7 is a bit misleading. The table represents the normal net position of the generators and consumers.

64 When expectations about the future change during the time, the expected price also changes. As a result, new contracts have other fixed prices. The contracts therefore do not cancel out completely. They differ on a fixed amount of money that has to be paid in each possible state in the future. Because this amount is independent of future states, this is not a real problem.

V. IMPLEMENTATION IN BELGIUM

A. Pre-liberalisation situation

The existing power system in Belgium[65] is dominated by the private company Electrabel. Electrabel controls 88% of production and 80% of distribution, through the mixed intermunicipalities. Electrabel also has the major share in CPTE, the Company for the Co-ordination of Production and Transmission of Electricity. Next to Electrabel, there is a smaller public utility, SPE (Samenwerkende vennootschap voor de Productie van Elektriciteit), with an 8.5 % share in CPTE and BCEO[66]. Electrabel is a 40% daughter company of Tractebel, itself acquired last year by the French Suez Lyonnaise des Eaux. 5% of Electrabel shares are held by the intermunicipal companies, the remaining 55% is in free float.

After the take-over of EPON in The Netherlands, Electrabel is the fifth largest generator in Europe, with some 100 TWh per year, but is still significantly smaller than EdF (455 TWh), ENEL (225 TWh), RWE-VEW (212 TWh) and PreussenElektra-Bayernwerk (180 TWh).

1. Generation

Generation is based for 55% on nuclear power plants in Doel and Tihange. Gas is used for 23%, and coal for 17%. The remainder is covered by small hydro-electricity plants and turbojets. All recent power plants are gas fuelled STAG (Steam and Gas) power plants. Overall capacity is 14 500 MW, peak load is 12 000 MW and annual electricity consumption is +/- 80 TWh. Figure V.1 shows the main power plants.

Cogeneration is encouraged by the government. 1000 MWe of cogeneration capacity should be developed by 2005. Autoproducers using renewable energy sources, cogeneration or waste energy are granted favourable tariffs. They are entitled to a bonus of 1 BEF/kWh, plus since July 1, 1988, another 1 BEF/kWh for electricity from hydraulic and wind energy. Electricity from photovoltaic energy is paid back at the same tariff as charged by the distribution for normal households. Furthermore, autoproducers can sell unlimited power during off-peak hours.

2. Transmission

The 380, 220 and 150 kV transmission network is owned by the CPTE. The CPTE controls the grid from their national dispatching centre in Linkebeek. The technical competence of the CPTE as network operator is not disputed.

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[65] The description is based on [12] to [14], [28] and [65] to [77]. It describes the situation up to 1999, with some comments on tariff developments in 2000.

[66] The BCEO is presented under paragraph V.A.6.a) of this section.

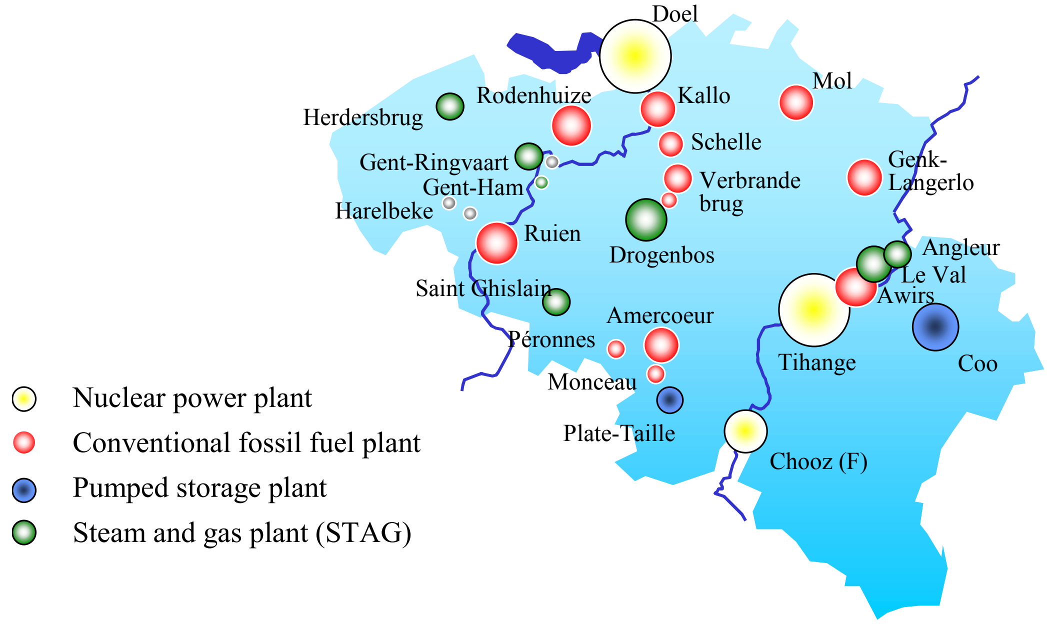

Figure V.1 Large power plants in Belgium

CPTE has accepted that the overall number of kilometres of overhead lines should not increase. New overhead lines must be compensated by replacing other lines with - far more expensive - underground cables. Recently, permission has been given to construct the 380 kV link between Avelgem and Gouy. Apart from this, the construction of new 380 kV lines is restricted. This strongly affects the ability to import, export and transit power. Figure V.2 shows the 380 kV grid, with the main interconnections with France and The Netherlands.

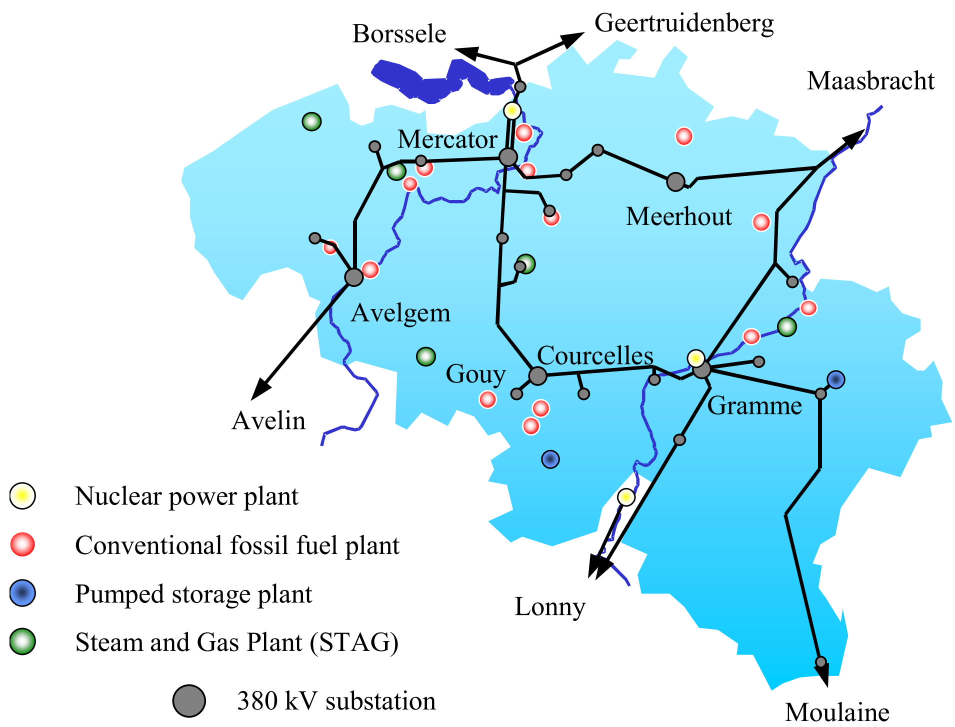

Figure V.2 380 kV grid in Belgium, 1995

3. Distribution

Municipalities have the legal monopoly on local distribution. Most of them work together with Electrabel in the so-called mixed intermunicipals, resulting in Electrabel participating in 80% of the distribution. The other municipalities control the distribution themselves in the so-called pure intermunicipals. 451 of the municipalities in mixed intermunicipals have signed long-term contracts with Electrabel, applicable till the end of 2011. From 2007 on, with a four-year notice and payment of compensations, the mixed intermunicipal companies can obtain between 20 and 25% of their demand from other suppliers.

4. Consumers

Table V.1 gives an overview of the different types of consumers in the Belgian electricity market in 1997, and their relative share in the electricity use. Autoproducers form 3% of the market. Consumers directly connected to the high voltage grid[67], and with an annual use of more than 100 GWh, make up 33% in 65 sites. Another 200 sites are directly connected to the high voltage grid, but use less than 100 GWh/year. These make up 4% of the market.

High voltage (i.e. > 10 kV) public distribution makes up 27%; 12% in the industrial and 15% in the tertiary sector. Low voltage distribution makes up the final 33%.

Group	Share of market (1997)
Autogeneration	3%
High voltage direct, > 100 GWh/year (65 sites)	33%
High voltage direct, < 100 GWh/year (200 sites)	4%
High voltage public distribution – Industry	12%
High voltage public distribution – Tertiary	15%
Low voltage (220 – 380 V)	33%

Table V.1 The Belgian electricity market, 1997 (Source: Febeliec)

5. Tariffs

There is continuing debate about the reasons for the high electricity tariffs in Belgium. A group of experts [], led by Erik De Keuleneer, quotes the depreciation rate of the nuclear power plants as the main reason. Given the fact these power plants are now depreciated, they feel significant tariff reductions of 15 to 20% are possible.

Electrabel does not agree with this view. They say the depreciation rates for power plants and transmission lines, as well as the Electrabel rendability, do not differ significantly from those in other countries. Willy Bosmans quotes different taxes and VAT-levels, high wages, important social benefits and municipal dividends as main reasons. [DS 1/3]

[67] In Flanders this means the consumers have a connection of more than 10 MW, in Wallonia the limit is 4 MW.

Last year already, in September 1999, the CCEG decided on tariff reductions of some 11 billion BEF. For July 2000, a further reduction of, on average, 0.10 BEF/kWh was announced for households and SME [DS 24/11].

In April 2000, the federal government decided there should be an average tariff reduction of 15 to 20% for households and SME in the next two years. Main elements are the abolition of the fixed tariff component for households and the 50% reduction for the first 500 kWh. Further details, and the implementation of similar reductions for SME, are left to the CCEG. Total cost would be of the order of 12 billion BEF for the household tariff reduction, and a similar amount for the SME. [DS 7/4]

It is not yet clear who will have to bear what part of this sum. Electrabel insists on reductions in VAT-level as part of the tariff reduction.

In May 2000, the results of the tariff comparison study ordered by the CCEG from Wefa were made public. It compares tariffs with France, The Netherlands, Germany and the UK. [DS 17/5].

Table V.2 summarises the results: it shows the price in Belgium, the average price in the four neighbouring countries, and the difference in percent, always without taxes and VAT. Only the largest industrial consumers, the largest residential consumers and consumers benefiting from the social tariff have lower prices than in neighbouring countries[68]. Others pay up to 19% more. On top of this, the Belgian VAT is higher than in the neighbouring countries.

Category	Price in Belgium [BEF/kWh]	Average price in F, NL, G and UK [BEF/kWh]	Difference [%]
Price for intermunicipals	2.12	1.9	+ 10.26
Small consumers (- 1200 kWh)	6.12	5.1	+ 16.63
Small consumers (social tariff)	4.56	5.1	- 11.67
Average residential consumers (+/- 3500 kWh)	4.37	3.93	+ 9.96
Large residential consumers (+/- 20 000 kWh)	2.34	2.42	- 3.52
SME small consumption	5.49	4.51	+ 17.71
SME average consumption (+/- 50 MWh)	5.59	4.52	+ 19.02
SME large consumption (+/- 160 MWh)	4.31	4.02	+ 6.72
Small industrial consumer (+ 1.25 GWh)	3.13	3.11	+ 0.57
Large industrial consumers (+ 10 GWh)	2.34	2.53	- 8.44

Table V.2 The Belgian electricity tariffs compared with 4 neighbouring countries, without taxes and VAT, 1999 [DS 17.05]

[68] But Fabrimetal claims that by April 2000 even the largest industrial consumers paid 13.5% more than in the neighbouring countries, due to the dramatic price drops in Germany. SME pay up to 25% more than in the neighbouring countries [DS, 18.05]

The study shows that the tariffs for the intermunicipals are 10% higher than in neighbouring countries. The intermunicipals themselves are responsible for an extra increase in cost to the SME.

Fabrimetal immediately reacted with an update of industrial and SME tariffs, showing Belgian tariffs as 13.5 to 26% higher than those in neighbouring countries. The deterioration is mainly due to the price war in Germany. [DS 18/5]

6. *Other actors*

a) BCEO

The BCEO (BeheersComité der ElektriciteitsOndernemingen), composed of representatives of Electrabel and SPE, is responsible for setting prices and for producing a detailed investment plan. Their proposals are reviewed by the regional authorities, the CCEG, and the National Committee for Energy, and approved by the government.

The last National Equipment Programme covers the period 1995-2005.

b) CCEG

The electricity and gas monitoring committee (ControleComité voor de Elektriciteit en het Gas, CCEG) has been the regulator for 40 years. This autonomous, public utility organisation is composed of controlling instances and controlled parties. The controlling instances are the trade unions and the VBO (Verbond der Belgische Ondernemingen), the association of Belgian enterprises. The controlled parties are Electrabel and SPE (through the BCEO), Intermixt and Inter-Regies (as representatives of the mixed and pure intermunicipals) and finally Figas and Gaselec (two gas-related parties). The federal and regional governments are represented as observers, with however a veto-right in those matters where they are competent.

The CCEG is responsible for ensuring that tariffs and economical and technical developments comply with general energy policy. They set plant depreciation rates, decide the contribution the sector makes to sustainable energy programmes and are responsible for a fund set aside for decommissioning nuclear power plants.

In future, their competence will be limited to the non-eligible market.

B. State of the implementation

The federal law on implementing the Directive has been accepted the 29th of April, 1999, and was published the 5th of May [74]. Most of the royal decrees for the detailed implementation and the nomination of the system operator are awaiting the advice of the regulator, who was nominated the 3rd of December, 1999.

While the federal government is competent for transmission, distribution is a regional responsibility.

1. Regulator

The structure of the regulator CREG (Commissie voor de Regulering van Elektriciteit en Gas) - who will also be responsible for the liberalised gas market - is given in figure V.3.

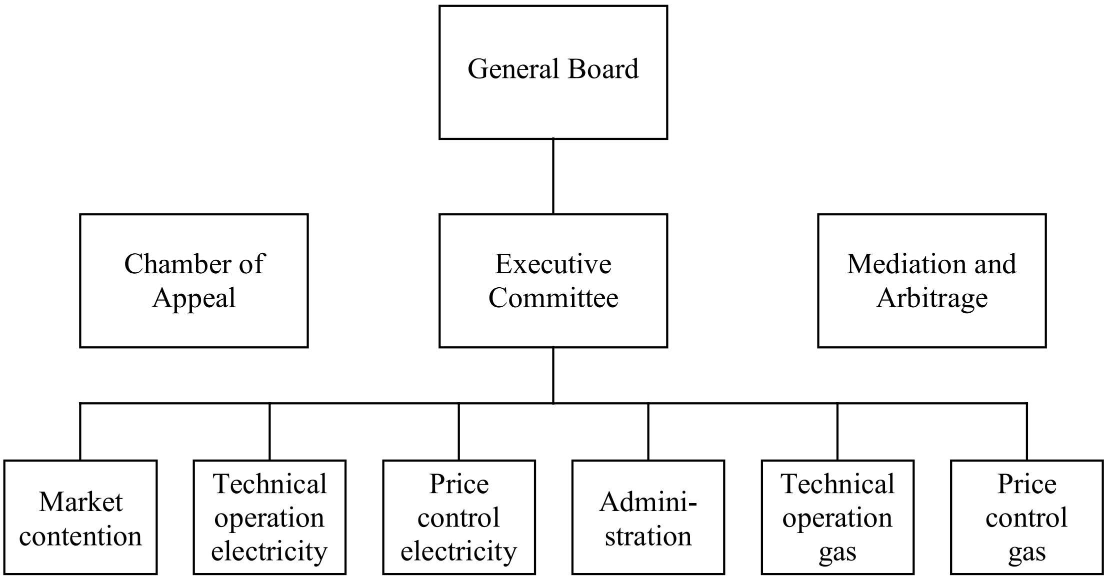

Figure V.3 Regulator [76]

The General board consists of representatives of all interested parties, i.e. the federal and regional governments, trade unions, employers, producers, distributors and consumers.

The Executive Committee consists of a chairman and 5 other members, responsible for market contention, technical operation of the electricity and gas market, price control of the electricity and gas market, and administrative matters. Members are appointed for 6 years, except for two of the initial members, who are appointed for three years.

The chairman is Christine Vanderveeren, the other members are Thomas Lekane, Jean-Paul Binon, Guido Camps, François Possemiers and Bernard Thiry.

Next to the two main organs, there is a Chamber of Appeal and a Mediation and Arbitrage Service.

2. Production

Every three years the Regulator presents an indicative program for generating facilities covering a period of ten years. It estimates the demand for electricity, sets guidelines for the diversified choice of primary energy sources, promotes production from renewable energy and evaluates the public service obligations.

Belgium opts for the authorisation procedure (i.e. licenses) for the construction of new generation plants. The criteria for this authorisation will be periodically adapted, taking into account the indicative generation program. When the number of demanded licenses is smaller than in the indicative generation program, the Minister of Energy launches an "appeal for interest".

Criteria for granting a license are:

- Safety and reliability of the electricity grid;
- Energy efficiency of the proposed installation;
- Nature of primary energy source;
- Professional, technical and financial capacity of the applicant;
- Public service obligations, regarding continuity and quality of supply, particularly for non-eligible clients.

Royal decrees are needed, after advice from the regulator, for the further implementation, e.g. for wind power at sea, and for the promotion of renewable energies through a minimum share in consumption.

3. *Transmission*

The owner(s) of the transmission grid appoint, after approval by the government, a Transmission System Operator (TSO) for a renewable period of 20 years. The TSO has to be independent, and his activities are limited to the tasks set out in Article 8. A royal decree of the 3rd of May, 1999, sets the rules for ensuring the independence.

The TSO has not yet been appointed, and possibly the acting system operator CPTE will be appointed as temporary system operator, for a period of two years, before a final decision is taken by the government [DS, 7.4].

The tasks of the system operator are:

- system operation and maintenance;
- improving and extending the grid, with a seven-year plan, updated every other year;
- dispatch of the power plants[69];
- providing ancillary services;
- providing third party access.

The Grid Code with technical rules for connecting to the grid has to be set by royal decree, after advice from the Regulator and in consultation with the system operator. The transmission tariff structure is set by royal decree, the actual tariff is set by the system operator, after approval from the Regulator.

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[69] Electrabel production and other producers have to inform the network operator of their intended dispatch schedule for the next day, before 12.00 h noon. The system operator has time until 16.00 h to approve of this plan, or to impose modifications on technical grounds.

4. Grid access

Grid access is based on regulated Third Party Access (TPA), except for transits and large volumes that have a negotiated TPA. A royal decree has to set the limits for defining these large volumes. Direct lines are subject to ministerial approval.

Grid access can be denied on technical grounds, i.e. lack of capacity or non-compliance with the grid code. Disputes will be settled before the Mediation and Arbitrage service and the Chamber of Appeal within the Regulator.

CPTE has published temporary transmission tariffs as acting system operator.

5. Opening of the market

a) Consumers connected to the transmission-grid.

The law of 24/4/1999 prescribes an initial opening for all consumers consuming more than 100 GWh per year, and an opening for all consumers directly connected to the high-voltage transmission grid by 1/1/2006. Intermunicipals would be free from 1/1/2007.

Table V.3 presents an overview of the various proposals for a faster opening of the market [DS, 22/4/2000].

	Federal law 24/4/1999	Group of experts 15/12/1999	Adaptation federal law (1)	Flanders	Wallonia
19/2/1999	> 100 GWh/year				
1/7/2000		> 20 GWh/year	> 20 GWh/year (2)	> 20 GWh/year green electricity	
1/1/2001					> 20 GWh/year
1/1/2002		> 10 GWh/year	> 10 GWh/year	> 10 GWh/year	
1/1/2003		> 1 GWh/year	all direct clients intermunicipals (3)	> 1 GWh/year	> 10 GWh/year
1/1/2004					
1/1/2005					all direct clients
1/1/2006	all direct clients	all consumers		all consumers	all consumers
1/1/2007	intermunicipals				

(1) draft (2) after consultation with the regional authorities (3) Belgium waits for the EC proposal

Brussels does not have an own calendar.

Electrabel opened the market for all consumers of more than 40 GWh on 1/5/2000, and will propose its own calendar for further opening, if no decision is taken by 1/7/2000

Table V.3 Various proposals for market opening

b) Consumers connected to the distribution grid.

The distribution companies are eligible for the consumption of the eligible end-users of their distribution-grid, the responsibility to free the end-users of the distribution companies lying with the regional authorities. The group of experts proposes the make intermunicipals eligible for the share of their free clients, one year before these clients become eligible.

The law of March 10, 1925 gives the municipalities the formal freedom to choose their electricity provider. This does not mean that the municipalities have an effective freedom. When they are not given the eligible status, they do not have the guaranteed access to the transmission grid. Almost all municipalities concluded contracts for 100% of their demand until December 31, 2006 and 75% until December 31, 2011. The government will gradually speed up the eligibility of the intermunicipals. (see Table V.3)

6. Public service obligations

The PSO's and their financing have to be decided by royal decree, as is the problem of the stranded costs.

7. Flemish draft decree

The Flemish government agreed on a draft decree. Major characteristics are:

- the immediate opening of the market for all consumers of more than 20 GWh/year;
- a progressive but fast lowering of this limit in the following years;
- a forced unbundling of distribution companies in a distribution system operator and a supply company;
- a system of green certificates from 2001 on, aiming at 3% of supply in 2004[70]. If a supply company does not achieve the 3% limit, they will be heavily penalised.

[70] The decree imposes the production of electricity from renewable sources to take place within Flanders. The EU would accept a minimum percentage of green electricity to be produced in each country separately, despite the fundamental rules of the open market.

VI. STRANDED COSTS IN BELGIUM

The stranded costs have to do with the transition from a regulated to a competitive electricity market. In the United States this reform started a few years earlier than in Europe, and as such the stranded costs problem has already been the subject of a discussion between the different actors and participants in the game. This discussion focused on several questions, such as what is the exact definition of stranded costs? Should the industry be able to recover them? If so, who should pay for them? And how should they be recovered? Obviously, the discussion in Belgium will concentrate on the same kind of questions and it is the purpose of this chapter to provide some conceptual background.

A. A definition of stranded costs

Electricity generating firms made different expenditures that are considered sunk or fixed. It would be wrong to label all of them as stranded when the electricity market is opened up, because some of those costs would also have been made in a competitive market. However, some fixed or sunk costs are typical for a firm operating in a regulated market. Because they were imposed by the regulator, or because the firm chose to make these costs. Concerning the first category, the fixed or sunk costs imposed by the regulator, one could argue that it should be allowed to the firm to recoup these costs, whatever the market structure is. We will call them *strandable costs*. However, it is difficult to defend this position for the latter category of fixed costs.

<table>
<tr><td colspan="2"></td><td colspan="2">SUNK COSTS IMPOSED BY THE REGULATOR?</td></tr>
<tr><td colspan="2"></td><td>Yes
↓
Strandable</td><td>No
↓
Not strandable</td></tr>
<tr><td rowspan="3">RECOVERABLE VIA THE MARKET?</td><td>Full recovery</td><td>Not stranded</td><td>Not stranded</td></tr>
<tr><td>Partial recovery</td><td>Non-recoverable part is stranded</td><td>Not stranded</td></tr>
<tr><td>No</td><td>Stranded</td><td>Not stranded</td></tr>
</table>

Table VI.1 The definition of strandable and stranded costs

This is summarised in Table VI.1. Two categories of fixed or sunk costs are distinguished, those imposed by the regulator and those resulting from decisions taken by the firm itself. In this paper, the costs in the first category are called *strandable*, those in the second category are *not strandable*. If stranded costs are present, then they should be in the strandable category, the non-strandable costs cannot become stranded. But not all strandable costs are necessarily stranded, since some of these costs can be (partially) recovered via the market. Only those strandable costs that *can not* be recovered via the market are stranded. In the table the shaded cells indicate the stranded costs. We will further elaborate on these concepts and their interconnection in the next section.

Summarising, in this chapter stranded costs are defined as *those fixed and sunk costs that were imposed by the regulator in the regulated market and that cannot be recovered via the market if the market is opened up for competition.* Comparing our definition with the ones found in the literature learns that it closely resembles the definition given by Baumol, Joskow and Kahn[71]. However, our definition puts more emphasis on the role of the regulator. We stress that the regulator should *impose* the expenditures, whereas Baumol *et. al.* include expenditures *approved* by the regulator. Clearly, this is a much broader definition of stranded costs because it implicitly opens the door for *all* sunk costs made by the regulated firm to become stranded.

However, for the purpose of this chapter, the exact definition of the stranded cost concept is not that important. The major purpose of the chapter is to illustrate – given the presence of strandable costs – how one should think about the subject from an economic efficiency point of view.

B. The economics of stranded costs : A graphical analysis

This section takes a look at the link between strandable costs, stranded costs and other cost concepts. Furthermore, it tackles questions such as when do stranded costs exist? If stranded costs exist, are there economic reasons to allow for stranded costs recoupment? Can, on a theoretical basis, anything be said about the size of the stranded costs? These question are answered by using graphical tools and the analysis is kept as simple as possible[72].

1. The regulated market

Assume that the total demand for electricity is perfectly inelastic and equals q_D. Initially, there is only one electricity-generating firm. This firm is called the incumbent and its cost structure is shown in figure VI.1. It is assumed that the average cost of electricity *generation* (AC_I) decreases for some smaller levels of output, but in the range we are considering the average cost of electricity generation is increasing. The incumbent's marginal cost of electricity generation is assumed to increase linearly[73]. The average variable cost is labelled AVC_I. The vertical distance between AC_I and AVC_I is then a measure of the average fixed generation cost AFC_I (not drawn in figure VI.1). The present analysis only considers the cost of electricity generation.

We assume that it is compulsory in the regulated market to meet the market demand and that the regulator sets the price for electricity generation such that economic profit equals zero, i.e. $p^R = AC_I(q_D)$. The latter assumption is made for illustrative purposes, and has no effect on the conclusions of the analysis.

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71 Taken from [80], p. 42.

72 More particularly, we focus on a market with one homogenous commodity. This can be electricity delivered at a constant flow over the year with a given level of quality. Using a multiproduct approach for electricity (peak, off peak, etc.) is more realistic but will obscure the stranded costs analysis in this section. The simulation model presented in the next section does however consider different consumer types and also extends the analysis in several other ways.

73 The linearity of MC_I (and thus also AVC_I) is assumed for the sake of simplicity. Unless it is mentioned explicitly, this does not influence the main conclusion of the analysis.

2. The liberalised market

Now assume that the market for electricity generation is opened up for competition and that the market demand for electricity remains equal to q_D[74]. Furthermore, assume that several potential entrants are competing for a market share and that each of these entrants has sufficient capacity to supply the market at a constant marginal cost (MC_E). This assumption may be a good approximation for what will happen on the Belgian electricity market. Belgium is a small open economy, with a relatively small production capacity compared to the available capacity in the surrounding countries.

Competition between entrants ensures that the entrant's price equals his marginal cost[75]. Furthermore, we assume that if the incumbent increases his price above the entrant's marginal cost, then he would immediately be pushed out of the market.

In figure VI.1, the market demand for electricity q_D is supplied by two generation firms, the incumbent (*I*) and the entrant (*E*). The vertical axis on the left-hand side is the incumbent's axis, the entrant's axis is at the right-hand side.

a) The competitive outcome

Under the assumptions listed above, the competitive market outcome will always be such that $p = MC_I = MC_E$, which is generally accepted as optimal from an efficiency point of view. In figure VI.1, the incumbent's output would reduce to $q*$, whereas the entrant's output would be $(q_D - q*)$. The implied price of electricity generation decreases ($p^C < p^R$), but this is not a general result. In fact the market price is determined by the marginal cost of the entrant.

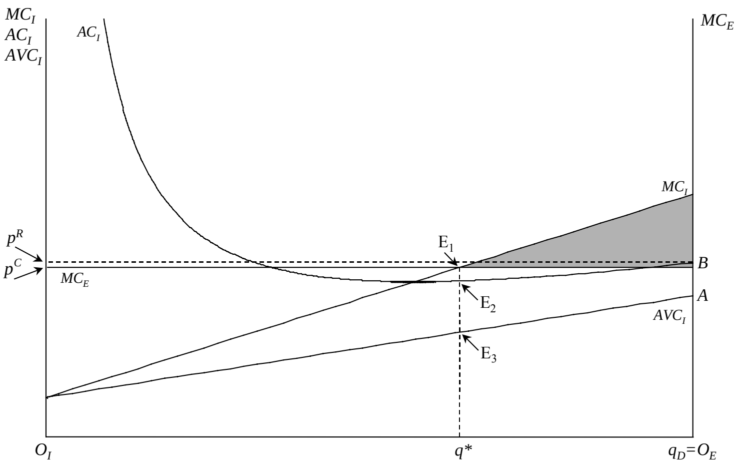

Figure VI.1 The competitive market

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74 It is assumed that one entrant enters the domestic market. The results would not change if more than one competitor would enter. The assumption of perfectly inelastic demand for electricity is acceptable in the short run and helps the exposition. We will relax this assumption in section 4.

75 In fact, we assume the entrant to be a competitive fringe.

b) Economic welfare

It can be shown that in this simple model social welfare increases as the market is liberalised. Furthermore, it can also be shown that the change in social welfare is equal to the efficiency gain that is made through improved production efficiency. The shaded area in figure VI.1 is a measure of this 'benefit'.

3. *The stranded costs*

In order to show the stranded costs in a figure, we need to take a closer look at the fixed costs. From section A, it is clear that only those fixed or sunk costs imposed by the regulator are candidates to become stranded, i.e. are *strandable*. In order to make this distinction, the fixed costs are divided in *strandable* and *non-strandable* fixed costs (F_S and F_{NS}). This results in the $AF_{NS}C_I$-curve in figure VI.2, which represents the average non-strandable fixed costs. The next two subsections consider two cases.

a) The market price covers the average costs

In figure VI.2, both the strandable and the non-strandable fixed costs are covered by the market price. The domestic firm produces q^* and makes an economic profit equal to the area $p^C E_1 E_2 D$. As was said before, from an efficiency point of view this market outcome is optimal. There is no reason why the government or any other regulator should intervene by allowing the recovery of strandable costs since the market automatically arrives in a Pareto-optimal situation. In fact, *there are no stranded costs in this case*.

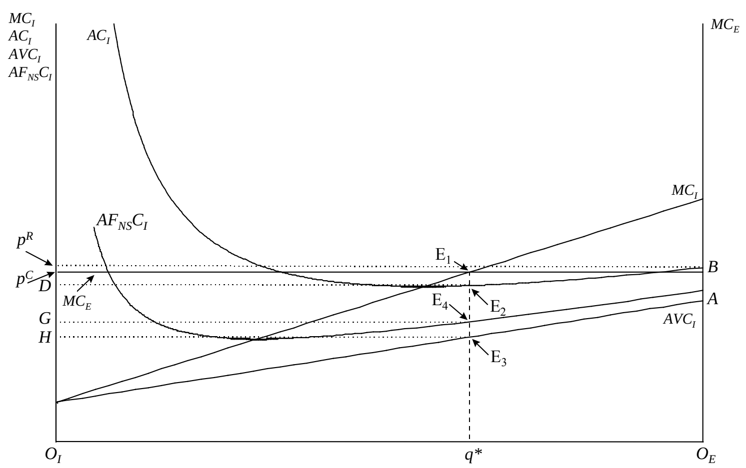

Figure VI.2 The competitive price is higher than the average cost of the incumbent

b) The market price does not cover the average costs but does cover average variable costs

In this case, the market outcome could be as shown in figure VI.3. Standard economic theory then suggests that in the short run the firm will stay in the market since stopping activity will only imply an even larger loss. The point E_1 indicates the short run price-output combination for the incumbent firm. This point implies a loss per unit of output equal to E_2E_1 and a total loss equal to the rectangle $DE_2E_1p^C$. The stranded costs in this case are equal to that part of the strandable costs that is not recovered via the market, which also equals $DE_2E_1p^C$.

Again, there is no case for allowing stranded costs recovery from the point of view of efficiency. The incumbent incurs a loss due to the presence of strandable costs, but this does not influence his output decision. The Pareto-efficient output will still be the outcome.

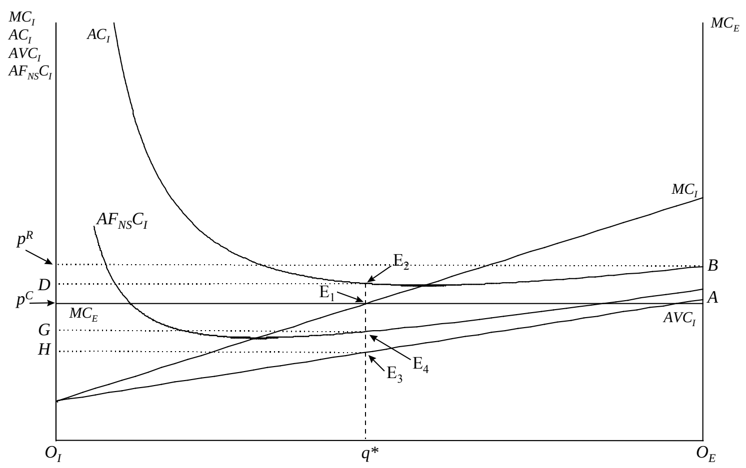

Figure VI.3 The competitive price is lower than the average cost of the incumbent

One could also turn around the question: is there a case for *not* allowing stranded costs recovery? No, there is neither. If the incumbent is allowed to recover stranded costs and if the recovery is organised in a competitively neutral way, then the firm will choose the same Pareto-efficient output. The difference between both cases is that the burden of stranded costs is (partially) shifted from the firm to the consumers and/or the government.

Standard economic theory also suggests that a firm, not able to cover its fixed costs in the short run, will leave the market in the long run. This is true, but in the present model, the situation might be slightly different because *strandable costs are a short run phenomenon*. In the long run, the owners of the firm will absorb the strandable costs, and the firm will only reoptimise its *non*-strandable fixed costs. If it is possible for the firm to cover its long run average costs (now not containing any strandable costs anymore) with the market price, then it will stay in the market. If on the other hand, the firm is not able to cover its long run average costs through the market price, then it will leave the market. From an efficiency point of view, this would even be optimal.

This reasoning puts an upper limit on the financial support for stranded costs recovery. The support may *not be larger* than the amount of the *strandable costs*. If the regulator sets the compensation at a level that covers more than the strandable costs, then he is subsidising some of the non-strandable fixed costs of the incumbent, which may create the wrong incentives for the incumbent. The incumbent may decide to stay in the market, whereas we know that this is not optimal from the point of view of efficiency.

C. *Some simulation results*

This section presents some numerical simulations. The basic features of the graphical model remain present in the numerical model, but the latter also includes some realistic extensions. Even then, the model is kept as simple as possible and focuses only on the most relevant aspects of the stranded costs discussion.

1. *A Brief Description of the Model*

The *demand* for electricity is modelled in a very simple and global way. It is assumed that the yearly demand for GWh depends on the price per GWh in a linear way. Two consumer types are distinguished: small (residential) consumers (including Small and Medium size Entreprises or SME) and large (industrial) consumers. No other possible market segmentations are distinguished.

The liberalisation of the electricity market is assumed to have no effect on the demand in the residential market (since competition is not allowed in that market), but it does have an effect on the demand in the industrial market as it is faced by the domestic producer of electricity. Technically speaking, the residual demand on that market becomes more elastic.

Before the liberalisation, electricity *supply* is provided by one domestic firm. After the liberalisation, this monopoly situation remains present in the residential market, but competition is introduced in the industrial market. Competition comes from foreign producers, as described in the previous section. In the base case, the domestic firm has no market power, i.e. residual demand is perfectly elastic.

It is assumed that the domestic firm behaves in a profit maximising way. The entrant's output equals the difference between the *market* demand at that price and the quantity sold by the incumbent. The cost structure of the electricity-generating firm is as described in the previous section. The model also takes into account transmission and distribution losses.

The model is calibrated for the Belgian electricity market in 1996. The data are taken from the annual report of the CCEG [65].

2. *The base case Simulations*

Table VI.3 (see VI.E) presents the results of 3 simulation exercises. Simulation 1 describes the regulated electricity sector in 1996, simulation 2 simulates the liberalisation of the electricity market for industrial consumers without stranded costs recovery and, finally, simulation 3 simulates a scenario for stranded costs recovery via a fee on transmission. The discussion in this section concentrates on the changes in the surpluses of the consumers, producers, the government and overall welfare. The results are presented in Table VI.2.

a) Simulation 1: Before the liberalisation

The average consumer price in the residential sector equals 4.92 BEF per kWh. In the industrial sector the consumer price equals 1.706 BEF per kWh (see Table VI.3 in section VI.E). Both (maximum) prices are imposed by the regulator[76]. At that price, the residential and the industrial sector consume 43 807 GWh and 25180 GWh, respectively. The incumbent's net profit from generation and transmission activities equals 24 290.4 million BEF. The net profit from participation in intercommunalities equals 5 447.2 million BEF.

b) Simulation 2: The opening of the market for the industrial sector (no strandable cost recovery)

Table VI.2 shows that under the base case assumptions the market liberalisation results in a *small welfare gain* for the *industrial consumers* (256 million BEF). This result depends on two critical parameters: the price of foreign electricity (1.50 BEF per kWh) and the price elasticity of the residual demand for electricity (- ∞). Both parameters will be the subject of a sensitivity analysis.

The *domestic producer's profit decreases* with 176 million BEF but remains positive. Thus, under the assumptions used in this simulation, there are no stranded costs. There is also a small decrease in the *government surplus* of about 67 million BEF because of the decreased corporate profit tax receipts. Overall, social welfare increases with about 13 million BEF per year. In general, the effects are rather small. This is due to the base case assumptions, as will become clear in the sensitivity analysis.

c) Simulation 3 : Strandable cost recovery through an access fee for all producers

Assume that one decides ex ante that a strandable cost recovery is allowed for a total amount of 15 billion BEF per year. From simulation 2 it is clear that this is not really needed as profits remain positive. A fee for access to the transmission grid is used as the instrument for recovery.

Social welfare decreases by 502 million BEF. The *main losers* are the *industrial consumers*. Two effects explain this result. First, the producers shift the transmission fee to the consumers, which increases their price for electricity. Second, as a consequence of the increased consumer price, less electricity is consumed. Because of the price ceiling, the incumbent can not use his market power in the residential market. As a result, in the residential market the full burden of the transmission fee is carried by the producer (the producer price decreases). The *producer's overall profit increases*, but with less than 15 billion BEF, the amount allowed as strandable cost.

[76] This is a simplification. The regulator only fixes maximum prices.

Base Case (ef = - ∞ and mcf =1.50)		
Change in	**Sim 2**	**Sim 3**
Consumer surplus	256	-4 850
Res	*0*	*0*
Ind	*256*	*-4 850*
Producer surplus	-176	4 403
Government surplus	-67	-55
Total change	**13**	**-502**
ef = - ∞ and mcf =1.20		
Change in	**Sim 2**	**Sim 3**
Consumer surplus	9 712	4 100
Res	*0*	*0*
Ind	*9 712*	*4 100*
Producer surplus	-3 371	1 468
Government surplus	-1 285	-1 073
Total change	**5 056**	**4 494**
ef =-2.10 and mcf =1.50		
Change in	**Sim 2**	**Sim 3**
Consumer surplus	-4 131	-8 412
Res	*0*	*0*
Ind	*-4 131*	*-8 412*
Producer surplus	2 712	6 601
Government surplus	1 034	783
Total change	**-386**	**-1 029**

Table VI.2 Changes relative to the regulated market outcome (in million BEF)

3. Sensitivity Analysis

The full simulation results are available in section VI.E. We primarily concentrate on simulation 2, because it appears that the major impact of the parameter changes considered in this section is on the effect of the liberalisation.

Sensitivity analysis suggests that *the elasticity parameter* has a relatively small impact on the *overall* welfare (Table VI.4). However, it does have a significant effect on the *distribution of the benefits and losses* from the market liberalisation. The more elastic the residual demand the more the benefits go to the industrial consumers. The less elastic, the more the benefits are taken by the producer, because inelastic demand allows the producer to take advantage of his market power. Once the liberalisation has taken place, the effects of strandable cost recovery on the distribution of the welfare gains are comparable to the effects in the base case simulations.

Table VI.5 contains the results of a sensitivity analysis on the *entrant's marginal cost* of electricity generation. Compared to Table VI.3, the results in this table are based on a marginal cost of electricity generation for the entrant equal to 1.20 BEF per kWh. Intuitively, a lower price of foreign electricity leads to increased social benefits from liberalisation. At the same time, the domestic producer will lose some of his profits. The industrial consumers reap the benefits. With this assumption, there is a large shift in the market share in the industrial market.

D. Summary and conclusions

This chapter studied the stranded costs problem for the electricity sector. Stranded costs have to do with the transition from a regulated to a more competitive market. A distinction is made between strandable costs and stranded costs. Strandable costs are fixed or sunk costs imposed by the regulator. Strandable costs become stranded when they cannot be recovered via the market when the market is opened up for competition. When one is concerned about economic efficiency, allowing for stranded costs recovery is not necessary. On the other hand, allowing for recovery would not hurt either, but if financial support for stranded costs recovery is given, then it should be organised in a competitively neutral way. Moreover, there is an upper limit to the size of the support, i.e. it may not be larger than the strandable costs. Of course, if there is no recovery of stranded costs, then the firm will make a loss on the home market but this does not result in inefficiencies.

A simple economic model was used to test what could be the welfare effects of a transmission fee to recover stranded costs. The effect on welfare of opening the electricity market for the big industrial consumers depends on the supply price of the foreign producers and on the ease with which the big consumers switch to another supplier. When the supply price of the foreign producer is only slightly lower than the marginal cost of the home producer, opening the market could give welfare gains and higher profits for the home firm. The welfare gains come from imports at lower costs than the indigenous production. Despite the loss of market share for the home producer, his gross profits are not affected much because of two reasons. First, the protected market is responsible for the major share of the gross profits. Secondly, the home producer might be able to charge higher prices at home for the market share he keeps at home. In the sensitivity studies, the opening of the market does not lead to negative profits and therefore the strandable cost would never become stranded.

Although the probability of stranded costs is rather low, one could imagine several types of ex ante allowances to recover strandable costs. A transmission fee would generate a welfare loss compared to the non-recovery case. This means that increasing the profits of the home firm by making the small or large consumers pay more will generate a net loss for the society as a whole.

E. Appendix: Full simulation results

Variable	*Sector*	*Unit*	*Sim 1*	*Sim 2*	*Sim 3*
Consumer price	res	*BEF/kWh*	4.920	4.920	4.920
Consumer price	ind	*BEF/kWh*	1.706	1.696	1.906
Producer price	res	*BEF/kWh*	4.066	4.066	3.892
Producer price	ind	*BEF/kWh*	1.706	1.696	1.696
Marginal cost of electricity generation		*BEF/kWh*	1.550	1.556	1.529
Marginal cost of electricity (generation → transmission)	ind	*BEF/kWh*	1.690	1.696	1.879
Transmission fee		*BEF/kWh*	0.000	0.000	0.210
Distribution fee		*BEF/kWh*	0.000	0.000	0.000
Demand with domestic producer	res	*GWh*	43 80	43 80	43 80
Demand with domestic producer	ind	*GWh*	25 18	25 55	23 68
Demand with entrant		*GWh*	0.0	302.5	0.0
Firm profit from distribution		*Mln BEF*	5 44	5 44	5 44
Net profit of generation and transmission activities		*Mln BEF*	24 29	24 09	29 18
Profit of the communalities from distribution		*Mln BEF*	17 55	17 55	17 55

Table VI.3 Full simulation results (marginal cost of the foreign entrant = 1.50 and elasticity of residual demand = - ∞).

Variable	*Sector*	*Unit*	*Sim 1*	*Sim 2*	*Sim 3*
Consumer price	res	*BEF/kWh*	4.920	4.920	4.920
Consumer price	ind	*BEF/kWh*	1.706	2.027	2.196
Producer price	res	*BEF/kWh*	4.066	4.066	3.892
Producer price	ind	*BEF/kWh*	1.706	2.027	1.986
Marginal cost of electricity (generation → distribution)	res	*BEF/kWh*	1.550	1.403	1.390
Marginal cost of electricity (generation → transmission)	ind	*BEF/kWh*	1.690	1.543	1.740
Transmission fee		*BEF/kWh*	0.000	0.000	0.210
Distribution fee		*BEF/kWh*	0.000	0.000	0.000
Demand with domestic producer	res	*GWh*	43 80	43 80	43 80
Demand with domestic producer	ind	*GWh*	25 18	15 01	14 12
Demand with entrant		*GWh*	0.0	10 84	9 56
Firm profit from distribution		*Mln BEF*	5 44	5 44	5 44
Net profit of generation and transmission activities		*Mln BEF*	24 29	27 30	31 62
Profit of the communalities from distribution		*Mln BEF*	17 55	17 55	17 55

Table VI.4 Full simulation results (marginal cost of the foreign entrant = 1.50 and elasticity of residual demand = - 2.10).

Variable	***Sector***	***Unit***	***Sim 1***	***Sim 2***	***Sim 3***
Consumer price	res	*BEF/kWh*	4.920	4.920	4.920
Consumer price	ind	*BEF/kWh*	1.706	1.385	1.586
Producer price	res	*BEF/kWh*	4.066	4.066	3.900
Producer price	ind	*BEF/kWh*	1.706	1.385	1.385
Marginal cost of electricity generation		*BEF/kWh*	1.550	1.245	1.245
Marginal cost of electricity (generation → transmission)	ind	*BEF/kWh*	1.690	1.385	1.586
Transmission fee		*BEF/kWh*	0.000	0.000	0.201
Distribution fee		*BEF/kWh*	0.000	0.000	0.000
Demand with domestic producer	res	*GWh*	43 807	43 807	43 807
Demand with domestic producer	ind	*GWh*	25 180	4 176	4 166
Demand with entrant		*GWh*	0.0	24 783	22 715
Firm profit from distribution		*Mln BEF*	5 447	5 447	5 447
Net profit of generation and transmission activities		*Mln BEF*	24 290	20 545	25 921
Profit of the communalities from distribution		*Mln BEF*	17 552	17 552	17 552

Table VI.5 Full simulation results (marginal cost of the foreign entrant = 1.20 and elasticity of residual demand = - ∞).

VII. TRANSMISSION PRICING FOR BELGIUM

A. General pricing criteria

In general, an ideal pricing mechanism should satisfy four criteria. This chapter describes these four criteria and the potential difficulties that may arise when trying to satisfy all four criteria in a natural monopoly market such as the transmission of electricity. Next, the general pricing rules, derived from economic theory, that accommodate these difficulties are discussed. Finally, a pricing mechanism for electricity transmission in Belgium is proposed.[77]

1. Provide incentives to the market participants

In general, prices are the instrument used in the economy by market participants to communicate with each other. Prices convey important economic information. Price changes should give incentives to consumers or producers to change their behaviour, i.e. to increase or decrease their demand or supply.

In fact, economic efficiency embraces three other efficiency concepts:

- Cost effectiveness: Goods or services must be provided at the lowest possible cost.
- Dynamic efficiency: This refers to the ability of a company to respond to changing market conditions, by producing more or better products and by using cheaper production processes.
- Allocative efficiency is achieved when the price consumers are willing to pay for an additional unit of a product is equal to the cost of providing this additional unit. In economic terminology, allocative efficiency is achieved if the price is equal to the marginal cost, i.e. the price should reflect the cost of the last unit of the good that is traded on the market.

Applied to the electricity transmission market, economic efficiency implies that the transmission prices should provide the electricity consumers and suppliers with the correct economic incentives in at least three ways:

- encourage an efficient location of new generation capacity and new consumers;
- encourage an efficient use of the existing network;
- encourage efficient investments in network expansion and maintenance.

2. Prices must allow system operators to cover their costs

This may seem to be an obvious criterion. If, in any kind of market, a provider is not able to recover his costs at the prevailing market price, then he has to adapt output and/or costs. If this is not possible, there is no reason to stay in the market.

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[77] More information can be found in [81] to [97].

However, in some cases, the available technology is such that it automatically results in a market with only one provider. For example, having more than one transmission or transport grid for electricity would be inefficient (a waste of resources), just as it would be inefficient to have more than one railroad network to cover a given region. This is because the fixed cost needed to build such a network is huge compared to the size of the market, such that the average cost of providing the service (transmission of electricity) is declining over the relevant range of output in the market. This implies that the marginal costs are below the average costs. Situations like this are called *natural monopolies*, because the lack of competition that naturally follows[78].

It can be shown that in the case of a *natural monopoly* the 'cost recovery' criterion is incompatible with the first criterion, stating that from the point of view of efficiency the price should be equal to the marginal cost. Marginal cost pricing implies that the price is below the average cost, i.e. the company makes a loss. Of course, this is not a viable situation in the long run.

3. *Prices should be non-discriminating*

Prices are non-discriminating if identical consumers, buying a good at the same place and the same time, pay the same price or in general receive the same treatment. This criterion does not imply that the market price must remain unchanged over a period of time. For example, there clearly is a distinction to be made between peak and off-peak demand for electricity. In periods of peak demand, there is increased probability of congestion on the transmission grid, and this should be reflected into transmission prices. Therefore, consumers purchasing electricity in off-peak periods should pay a lower price than consumers buying electricity in peak periods.

There is also a relation between the place on the grid where electricity is produced or delivered and transmission losses. Clearly, this could also have an effect on the transmission prices. Thus, different transmission prices, according to the place where an electricity generator or a consumer is located, do not indicate discriminating behaviour, as it is a reflection of efficiency.

4. *Prices should be transparent*

It is desirable that the pricing mechanism applied by the regulator is transparent in the sense that all the parties involved (consumers and producers) understand the price structure and can take the structure into account in their decisions.

[78] Competition would not even be viable. In general, the transmission or transport activities of the electricity sector are in the hands of one single company and they are considered to be natural monopolies. Until a few decades ago, it was thought that electricity generation was also exposed to this phenomenon of decreasing average costs and it is only recent that electricity generation activities are not considered as natural monopolies any more.

B. Matching efficiency and cost recovery

In general, these four criteria are satisfied if the market structure is perfectly competitive, i.e. if no individual consumer or supplier of transmission facilities can influence the market outcome through his own behaviour. However, it has been mentioned before that this condition is not satisfied in the transmission of electricity, being a natural monopoly.

Being alone allows the transmission provider to influence the market outcome in a way that maximally increases its own profits at the expense of overall economic welfare. If the TSO is allowed to do so, it charges a price higher than the price available under perfect competition and thus also higher than the marginal cost. Thus, the first criterion is not satisfied anymore.

In that case, there is a role for a benevolent regulator wishing to maximise economic welfare. This could be done by *imposing* a price on the market, preventing the TSO from charging the monopoly or any other price. If the regulator imposes a price equal to the marginal cost, the resulting outcome will be the same as in the perfect competition case, satisfying the allocative efficiency criterion.

However, implementing marginal cost pricing results in a loss for the monopolist and in the long run, there is no reason why the monopolist would stay in the market. However, if the monopolist does leave the market, then economic welfare will even fall below the level obtained in an unregulated market.

One solution might be to subsidise the monopolist’s financial loss. Of course, this subsidy would have to be paid by the taxpayers and it is known from taxation literature that this creates distortions in the economy and thus lowers economic welfare. The trade-off between allocative efficiency and cost recovery has led to alternative pricing rules satisfying a revenue requirement for the monopolist but having prices closer to marginal cost than simple average cost pricing. Examples are *Ramsey pricing, two-part tariffs* and *peak-load pricing*.

1. Ramsey pricing

With Ramsey Pricing, the regulator searches for the *linear pricing rule* maximising overall economic welfare subject to a revenue constraint for the monopolist. With linear pricing, one single price is charged for each unit of a product sold, industrial and residential demand e.g. being considered as a different product.

The regulator takes into account the fact that collecting taxes to finance the monopolist’s deficit results in distortions and inefficiencies. Since the behavioural reactions – the attempts to avoid the effect of policy measures – cause inefficiencies, it is best to increase the price most in that market where the behavioural reactions are smallest. The industrial demand for electricity is more responsive to price changes, and therefore the overall inefficiency is smallest when increasing prices the most in the residential market.

However, implementing this pricing mechanism may be more difficult than it seems at first sight, due a.o. to the uncertainties in price elasticity.

2. Two-part tariffs

More recent work shows that *non-linear pricing schemes* have better efficiency properties than linear ones as they distort demand to a lesser degree. With non-linear pricing schemes, consumers are charged different prices for different blocks of demand. One example is the *two-part tariff*. With this pricing scheme a lump-sum amount is charged (a standing charge) to cover the common costs and additional units are charged at marginal cost.

Application of two-part prices is especially apt in the case of transmission, where it is difficult to produce an acceptable definition of use tied to any subset of the network. Any attempt to recover all or some of the fixed costs of the transport network based on variable charges confronts the problem of defining who is using which facility, and why. In a free-flowing electrical transmission grid, power may flow in ways that are beyond the control or intent of the user[79]. And if the short-run opportunity costs are significantly different from some pro-rata allocation of the long-run capital costs, a one-part tariff averaging fixed costs along with variable costs can produce inefficient incentives and contentious debate over complex and changing allocations.

These problems can be handled through the effective application of a two-part price. Ramsey pricing and two-part tariffs are at the basis of transmission pricing in the electricity and gas market.

3. Peak-load pricing

Another pricing rule often used in the context of regulation is peak-load pricing. This pricing mechanism is typically used when the three following features apply:

- Demand fluctuates systematically over a period (e.g. year, week, day), such as peak and off-peak demand for electricity;
- The produced good or service can not be stored or is very costly to store;
- The production process requires an investment in capacity that is unalterable for some periods of time, implying that the production capacity is determined by peak demand.

The resulting principal pricing guidelines can be summarised as follows:

- From the point of view of society, the peak price should be equal to the sum of the marginal operational and the marginal capacity cost. The off-peak price should be equal to the marginal operational cost. The intuition for this result is that peak period consumers determine the total need for capacity. Therefore, they should pay for the capacity.
- If the regulator also has to take into account the regulated firm's revenue constraint, the pricing rule reduces to the Ramsey pricing rule, where the prices are inversely related to the elasticity of demand and are also a function of the marginal cost of public funds.

[79] Cf. the "lake" analogy as introduced in II.B.1.b).

C. Typical issues for electricity transmission pricing

This section lists some additional issues typical for the electricity market and having an impact on the resulting pricing mechanism.

Electricity must not only be generated, but it must also be delivered at a given node, accounting for transmission constraints (congestion) and transmission losses. Both elements should be reflected in the transmission prices.

1. Transmission congestion

If transmission constraints are binding, so that the amount of power flowing through a line is at the safety limit, cheap but distant generation may have to be replaced with more expensive local generation, in order to reduce power flows. In the constrained area, the optimal price of electricity rises to the marginal cost of the local generation, or to the level needed to ration demand to the amount of electricity available[80].

2. Transmission losses

Even if there are no constraints, power is lost in the transmission process and prices should reflect the fact that marginal losses are higher in some places than in others.

3. Other elements that affect transmission prices

a) Ancillary services

The costs associated with delivery of electric energy include many services. The direct fuel cost of generation is only one component. In analyses of energy pricing, there is no uniformity in the treatment of the other, ancillary services (transport lines with sufficient reliability, spinning reserve, standing reserve, replacement reserve[81], reactive power (voltage control)[82],

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[80] Congestion has to be avoided for economic but also for reliability reasons. The total cost of capacity, losses and reactive power requirements of a line are minimised when the line is loaded at around 50% of its capacity. For reliability reasons, the loss of a line may not lead to a system collapse. With two identical lines in parallel on a route, this is achieved automatically by not loading the lines above 50%. When alternative routes exist, higher loading is of course possible. However, higher loading leads to an increased risk of voltage instability. Even though there is no sharp limit, a maximum safe rating is calculated for every line, depending on temperature and power factor of transmission over the line. It should be noted that power flows in the opposite direction of the dominant power flow diminish the total power flow, and relieve congestion.

[81] A characteristic of electricity is that it can not be stored. At each second, generation has to match demand, which fluctuates unpredictably. This is the so-called generation-demand balancing. To achieve this, power plants do not operate at maximum power, but keep a certain amount of reserve. The power output from all plants is constantly adapted, automatically, in a matter of seconds. Reserve power is also used for compensating large unbalances, due to e.g. errors in predicting demand and generator failures. If the amount of instantaneously available reserve power (the spinning reserve) is used, other power plants that were at stand-by are started up (standing reserve). These power plants are replaced in their turn by power plants designated as replacement reserve.

[82] Power in an AC system consists of active and reactive power. Active or real power is the power component that can be transformed in any other form of energy, such as mechanical energy. It can be transported over large distances, although there always is some loss. Reactive power is needed to maintain the overall voltage level in the grid, enabling the transport of real power. Reactive power itself can not be transported over large distances or imported from other countries, i.e. it has to be produced locally.

The blackout in a large part of The Netherlands in the summer of 1997 is an interesting example of one of the risks due to a large import of electricity (i.e. active power only) combined with a very significant independent generation (decentralised production) and an inappropriate price structure. The independent generators are only paid for their active power output. The ensuing lack of reactive power in the grid was the main cause of the blackout. It is clear future price structures have to incorporate a compensation for the reactive power.

'black-start' capability[83], active power losses, area control error[84]). These services have to be supported by adequate dispatching and metering systems.

b) Market power at the supply side

When at the generation side, the number of suppliers is limited (as will probably be the case in Belgium), then strategic behaviour might occur in the sense that the suppliers will try to influence the market outcome through their own behaviour. This might be possible, because changes in demand or supply in one node of the transmission grid have an impact (through transmission losses and capacity constraints) on the transmission prices in the whole grid. Clearly, the possible existence of such behaviour must be taken into account when a pricing mechanism is designed.

Green (1998) compares a nodal transmission pricing system with more simple mechanisms with respect to the welfare outcome. His conclusion is that using simpler pricing schemes decreases overall economic welfare, but not necessarily to a large extent.

D. Implementation for Belgium

In the firmly linked Belgian grid, in which actual power flows are very difficult to predict due to the large number of parallel paths and the dynamic characteristics (open switches or maintenance), marginal cost pricing is almost impossible. Therefore, we propose a pricing scheme starting from a postage stamp method, with improvements to give incentives for optimal siting of new generation and demand in the future, efficient use of the existing grid and cost minimisation. The postage stamp is applicable to both producers and consumers.

The regulated TPA tariff is only aimed at high-voltage transmission, i.e. voltages of 30 kV and higher. In case of a voltage dependent tariff, the grid would be divided in "extra high voltage" (i.e. 380, 220 and 150 kV) and "high voltage" (i.e. 70, 36 and 30 kV). The tariff system can be replaced by a negotiated tariff for large or specific contracts.

1. Postage stamp for cost coverage and non-discrimination

The annual postage stamp tariff should allow the transmission company to recover its costs for running the system while treating all grid customers, using the grid at the same time and place, in a similar way. Starting from the existing situation, these costs should include all functions the system operator has to provide:

- maintenance, general improvement, increasing reliability and keeping the system in line with the present state of technology (protection, measuring, metering, computer and information technology systems, replacing transformers and substituting overhead lines by underground cables under governmental pressure, new systems such as static VAR

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[83] The ability to restart the power system after an overall black-out, without support from other countries.

[84] Each country, or to be more precise each control area, performs generation-demand balancing, taking account of the scheduled import or export. This intended level of import or export is called the area control error.

compensators, FACTS, active filters,…) – this cost will be referred to in short as 'maintenance cost';[85]

- reserve capacity (spinning reserve, standing reserve and replacement reserve);
- reactive power and voltage control;[86]
- black start capability, bought by the transmission company from generation companies;
- losses in the grid;
- metering and billing of energy and power flow;
- personnel and operational cost.

Next to the actual costs, a fair return on investments should be part of the basic postage stamp rate.

a) Individual cost component

Costs that can clearly be identified as being due to a particular customer are charged to this customer. These include:

- connection cost (being different for different voltage levels);
- metering and billing;
- reactive power for outlyers.

The reactive power provision assumes a normally operating system, with generators and consumers following minimum standards for coming onto the grid, as prescribed by the system operator. If the clients do not meet these standards regarding reactive power (such clients are called outlyers), they have to be charged for it on top of the basic postage tariff, as the TSO has to take care of it. The TSO can then either shop for reactive power or use its own resources to provide it. This applies to consumers not meeting the required power factor, or to generators not taking part in reactive power regulation. Import of power is also considered as an outlyer, as it does not take part in reactive power regulation.

b) Demand component

Fixed costs, i.e. maintenance, general improvement, increasing reliability and keeping the system in line with the present state of technology, black-start capability and personnel cost plus the fair return on investment, are charged per kVA peak demand.

In order to avoid cross-subsidies between grid users at different voltage levels, it can be argued that all transmission clients (generators, consumers, traders, brokers,...) directly connected to the extra high voltage grid (380, 220 and 150 kV) should only be charged for the extension and maintenance of the extra high voltage part of the grid. Consumers or generators connected to the high voltage level (70, 36 and 30 kV) should be charged for the entire grid

[85] This cost, part of the demand component, is considered separately for the different voltage levels, i.e. extra high and high voltage.

[86] The cost of reserve and reactive power, making up the energy component, is considered separately for the different voltage levels, i.e. extra high and high voltage.

(30 to 380 kV). This assumes that all power passes through the extra high voltage grid, or at least that all customers benefit from the extra high voltage grid.

In this respect, the present system with various types of contracts (clients requiring only 50 Hz and meeting power fluctuations – clients requiring back-up power if available – clients requiring total system services) could be largely maintained.

c) Energy component

Variable costs, i.e. the costs of losses, reserve and reactive power, are charged per kWh. For consumers, the transmission tariff could be expressed per kVAh, in order to include an incentive to the consumer to minimise his reactive power requirements. For generation, a minimum amount of reactive power, relative to the capacity of the power plant, inductive as well as capacitive, must be available to the system operator, as defined in the grid code. Extra reactive power requested by the system operator must be paid for by him.

In order to avoid cross-subsidies between users at different voltage levels, the cost of losses, reserve and reactive power is differentiated per voltage level, through a charge based on a voltage dependent multiplication of the actual consumption. The following table VII.1 suggests a possible differentiation.

Voltage level of customer	Multiplication loss factor γ_{VL}
380, 220, 150 kV	1.02
70, 36, 30 kV	1.04
< 30 kV	1.08

Table VII.1 Multiplication loss factor γ_{VL} depending on voltage level

This again assumes that all power passes through the high voltage grid. Producers at lower voltage levels with nearby long term consumers could negotiate with respect to this multiplication factor.

This simple approach could in future be replaced with more accurate calculations, as explained in the discussion of the Grid Quality Charge. This calculation should indicate – in average, but perhaps not for each individual node - the dependence of losses, reserve and reactive power on the different voltage levels.

d) Basic postage stamp

These three charge components lead to a basic postage stamp for transmission:

$$TT_t = ICC_t + \frac{TFC_{t-1}}{\sum PD_{t-1}} \cdot PD_t + \frac{TVC_{t-1}}{\sum(\gamma_{VL} \cdot EC_{t-1})} \cdot (\gamma_{VL} \cdot EC_t)$$

with:

- TT_t: Transmission Tariff in year t for a particular customer, in [BEF/yr];
- ICC_t: Individual Cost Component, comprising connection cost, metering and billing cost and reactive power cost for outlyers, in [BEF/yr];

- TFC_{t-1}: Total Fixed Cost in year t-1, i.e. cost of maintenance (voltage level dependent), black start capability, personnel and return on investment, in [BEF/yr];
- PD_t: Peak Demand or Delivery of the customer in year t, expressed in [kVA];
- ΣPD_{t-1}: Sum of Peak Demands in year t-1, expressed in [kVA];
- TVC_{t-1}: Total Variable Cost in year t-1, i.e. cost of losses, reserve and reactive power (excluding outlyers), in [BEF/yr];
- EC_t: Energy Component in year t, expressed in [kWh] for generation and [kVAh] for consumption;
- γ_{VL}: Voltage level dependent multiplication factor
- $\Sigma(\gamma_{VL} \cdot EC_{t-1})$: Sum of Energy Components in year t-1, expressed in [kWh] for generation and [kVAh] for consumption, including multiplication factor.

The tariff as defined until this stage, does not give any incentive towards efficient use of the grid, siting of new generation or demand, congestion avoidance or future investments, except for the voltage level dependence and the penalty for reactive power outlyers.

2. Incentive for dispatching generation and for the siting of new generation or demand

The TSO should provide incentives for both dispatch of generation and for future investments in generation and new demand nodes to be located at those places where they best support the overall system regarding congestion, losses (including those under peak conditions), voltage stability, reliability and safety. A certain generator may be at a point in the grid where its presence is essential to maintain voltage stability. Therefore, the value of that generator should be higher than that of a generator at a very stable node. This differentiation would be expressed in the Grid Quality Charge (GQC).

The GQC could be calculated based on a comparison for all relevant nodes of losses and congestion with and without extra generation or demand. Generation and demand nodes would be ordered separately. Nodes that support the grid more than the average would benefit form a negative GQC, i.e. a reduced postage stamp. Nodes where extra generation or demand leads to an increase in losses and congestion, would be charged a positive GQC, i.e. a higher postage stamp.

Congestion can be taken into account by adding the weighted active and reactive loss in each line, cable and transformer, with as weighting factor a function of the loading of each of these elements, stressing the losses in lines that are more than 50 % loaded[87]. It is expected these calculations will show a different average impact of transactions, depending on the voltage level, as mentioned in section VII.D.1.c)

[87] A third calculation could be required here in order to obtain accurate results for large transactions, if these are not the subject of specific calculations.

Different reference load flows can be used, based on average load flows for weekends and weekdays, on- and off peak moments, and winter, summer and intermediate season.

Including the impact on reliability, stability and safety has to be based on the know-how of the system operator.

The applicability of the GQC in the Belgian grid is being studied at the moment.

The surplus charge and reduction are calculated in such a way that their combined effect for the network operator is zero. The transmission tariff becomes:

$$TT_t = ICC_t + \frac{TFC_{t-1}}{\sum PD_{t-1}} \cdot PD_t + \frac{TVC_{t-1}}{\sum(\gamma_{VL} \cdot EC_{t-1})} \cdot (\gamma_{VL} \cdot EC_t) + GQC$$

with

- GQC: Grid Quality Charge, either positive or negative, with $\Sigma GQC = 0$;

This charge is calculated and published for each node of the grid as it was in the previous period. The study is repeated after major grid modifications, and at least once a year. As the basis for the charge is time dependent (on and off peak, general load situation due to day of the week and/or season), this charge should be time dependent.

The Grid Quality Charge for border nodes may have to be recalculated at very short intervals given the possibility of sudden and major changes in import and export power flows due to trading. For other nodes in the Belgian grid, the effect of these fluctuations could be averaged out.

For particular investments, the parties involved may require the grid operator to make a confidential study of the precise effect for their intended investment in the potential nodes.

The node dependent surplus or discount leads to a better dispatching, reducing congestion and losses and improving the network stability. In this way they encourage efficient use of the existing network. They also are a long-term incentive for siting new generation or demand.

3. Transparency

Clearly all tariffs should be published for transparency and in order to allow the clients to take the necessary actions to use the system in an optimal and efficient way. This includes the node dependent Grid Quality Charge.

4. Incentive for efficient operation and network investment

a) Maintenance and operation

The system operator should be rewarded or penalised for the quality of his operation, including maintenance, switching of lines, voltage regulation, ... The criterion is the overall system reliability. The best way to judge this is to measure the amount of energy in kWh that has not been delivered to the consumers, or the amount of energy not taken from the cheapest generators because of system failure or congestion. The quality could be compared with neighbouring systems.

b) Investment and network expansion

By investing, the network operator can improve the quality and reliability of the power system, thereby reducing penalties. Furthermore, included in the total cost leading to the basic postage stamp rate, is a fair return on investment and capital cost.

However, all this may lead to over-investment and a gold plated network. Therefore, an incentive for overall cost reduction is needed.

c) Incentive for cost reduction

This is a fundamental problem in any monopoly system. The best solution is a system of benchmarking, through comparison with similar power systems in other countries.

In function of the quality of the system operation and the cost reduction, compared to neighbouring countries, the basic postage stamp rate is modified. The System Operator is penalised for over-investment, as the cost reduction is smaller than in similar systems. In the postage tariff, TFC_{t-1} and TVC_{t-1} are multiplied by a factor smaller than 1 in the case of over-investment, compared to other power systems. The transmission tariff finally becomes

$$TT_t = ICC_t + \frac{f(bm) \cdot TFC_{t-1}}{\sum PD_{t-1}} \cdot PD_t + \frac{f(bm) \cdot TVC_{t-1}}{\sum (\gamma_{VL} \cdot EC_{t-1})} \cdot (\gamma_{VL} \cdot EC_t) + GQC$$

with f(bm) a factor depending on benchmarking. Great care has to be taken in selecting systems that are comparable with the Belgian grid, and in making a fair comparison taking due note of objective differences.

E. International context

1. Frequency control

The costs incurred by the TSO to fulfil its international obligations are to be included in the Total Fixed Cost.

2. Import, export and transit

Referring to the (international) transmission tariff as proposed by the European TSOs [5]:

$$T_{tot} = G_1 + \sum_{i=1}^{n} (k_i \cdot T_i) + L_n$$

and to the image of the transmission grid as a lake, where distance between producer and consumer is irrelevant, the transmission tariff within Belgium would consist of an annual point-of-access charge, applicable to both producer and consumer, i.e.

$$T_{tot} = G + L$$

Within the Belgian control area, there is no T-component. Both G and L are calculated along the same general guidelines.

For international transmission, the analogy of the lake can be extended to a number of lakes, each representing one country, interconnected with channels, representing the physical interconnections. Within each country[88] generation-demand matching is performed, taking into account the net import or export. E.g., assume France is exporting 500 MW to Portugal, through Spain. France would perform generation-demand matching, aiming at a 500 MW generation surplus. Spain would aim at perfect generation-demand matching, and Portugal would aim at a 500 MW generation deficit.

Unlike the situation with one country, or one lake, where no relation between physical flows and individual inputs and outputs can be found, there is in this instance a clear physical flow, resulting from the net generation-demand mismatch in the different countries. This also implies that, in our view, some kind of T-element in the transmission tariff is justified.

According to the most recent evolution on a European level, as described in section II.B.4.a), countries would only receive a compensation for cross-border exchanges in the case of transit, and not for import or export separately. This may lead to inequalities, depending on the degree of import and export. Luxembourg e.g. produces some 15% of local consumption, imports 95% and exports 10%. This means transit is only 10%, and Luxembourg would only receive compensation for this 10%.

A further and more detailed study of the impact of the latest ETSO and ERF proposals is needed. In our proposal, import and export are treated similarly as local generation and demand. Each TSO only charges for costs in his network, avoiding pancaking.

a) Import

Import should be treated similarly as locally generated power, with the border node(s) as generation node. The transmission tariff becomes:

$T_{tot} = G_{import} + L$ or in the terms of [5]: $T_{tot} = T_{import} + L$

The Grid Quality Charge for G_{import} is calculated for the border node(s), taking due account of the benefits of opposing flows. As mentioned before, these QGC's may have to be recalculated fairly often, perhaps even hour by hour, in case the import/export pattern fluctuates significantly. In case of a stable average pattern, e.g. import from France and export to The Netherlands, import from The Netherlands would be supported, and import from France discouraged, alleviating possible congestion problems. Either way, the GQC gives the correct momentary or average incentives for efficient use of the existing network.

One difference with locally generated power is the fact that no reactive power or voltage support is provided. If one would suppose, in the extreme, that all power was imported, a problem would occur with respect to reactive power and voltage stability. Therefore, it is reasonable to include these extra costs in the Individual Cost Component of the postage stamp. In other words, import is considered an outlyer for reactive power. The transmission tariff would be charged to the consumer in Belgium.

[88] To be more accurate: within each control area.

One minor problem is the reserve power for import. When power is imported, reserve power has to be available at the supplier side and this has to be proven by the importer. If this can not be done, the importer has to buy reserve power via the TSO locally.

b) Export

An export node should be treated as a load, but the transmission costs are charged to the generator in Belgium. Applying the same reasoning, the transmission tariff becomes:

$T_{tot} = G + L_{export}$ or in the terms of [5]: $T_{tot} = G + T_{export}$

The treatment of import and export in this way makes it transparent for the TSO: whether the power is produced within its control area or not is of no importance.

c) Transit

The last point is transit power. This should be treated as in the import/export discussion above. The same postage stamp tariff with all surpluses has to be used, charged to the TSO's of the involved neighbouring areas. Reactive power is one of the major concerns here. The transmission tariff in Belgium becomes:

$T_{tot} = G_{import} + L_{export}$ or in the terms of [5]: $T_{tot} = T_{Belgie}$

d) Harmonisation with neighbouring countries

Germany uses a point-of-access charge from 2000 on. However, in their system the complete transmission tariff is charged to the consumers. In The Netherlands, 25% of overall costs is charged to producers, and 75% to consumers. In the proposal for Belgium, costs are divided equally between producers and consumers.

This difference leads to a competitive advantage for German producers, and in a lesser extent to Dutch producers, compared with Belgian producers. Clearly, harmonisation on a European level is needed, as recognised in the ERF meetings [6] and [10].

3. Uncontracted power flows

Until now, contracted power flows were discussed. The real problem is caused by so-called loop flows. Say, for instance, The Netherlands have a contract for import from Germany, and Germany has a contract for import with France. Due to the impedance characteristics of the interconnected grid, it may be the case that the physical energy flow is from France to The Netherlands through Belgium, without prior notification to the Belgian TSO. The path from France to Germany and from Germany to The Netherlands is referred to as the contract path.

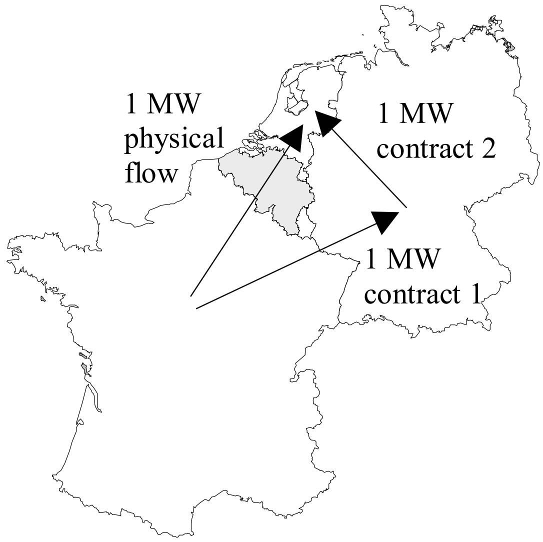

Figure VII.2 Loop flow

Post-factum calculations have to be used based on measured flows, and arrangements have to be made to obtain the normal transport charges afterwards, as in the case of contracted import/export through the Belgian grid.

Basically, an improved international co-operation between the system operators should prevent the existence of unannounced loop flows. If this is impossible and loop-flows cause severe problems with extra costs, these have to be recovered from the neighbouring system operators who were not willing to divulge the relevant information.

The need for abandoning the contract path fiction and using measured flows instead is another point recognised in the latest ERF meetings in Florence [6] and [10].

VIII. CONCLUSION AND SUGGESTIONS FOR FURTHER STUDY

There is a clear progress in the opening of the electricity market. All Member States, including France, have implemented the Directive. The evolution in Germany, The Netherlands, England/Wales and the Scandinavian countries has been studied in some detail.

Two important issues that remain to be agreed upon on a European level, are the stranded costs recovery, and the harmonisation of the transmission tariffs, especially for import, export and transit. Recent progress on the ERF meeting in Florence was described in section II.B.

Section IV gave an overview of the market operation.

Our view on stranded costs was discussed in section VI, concentrating on the situation in Belgium.

For Belgium, the regulator has been appointed. Advice from the regulator is eagerly awaited on a number of royal decrees for the detailed implementation of the new law on the electricity market, dating from April 1999. The nomination of the system operator is still being delayed, and possible CPTE would be nominated as temporary system operator only, for a period of two years.

The proposal for a transmission tariff in Belgium was presented in section VII.D and, for the international context, VII.E. This proposal is different from the ERF proposal, in the way not only transit but import and export separately are considered as justifying some cross-border tariff.

A particular element in the proposed Belgian transmission tariff, is the Grid Quality Charge, giving incentives for both producers and consumers. The applicability of this GQC is being studied at the moment on a complete model of the Belgian grid.

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