Congestion Management, Incentives and Regulatory Institutions in a Regional Electricity Market

Virginie Pignon[*]

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Abstract

This paper shows that the coordination of electric power submarkets as a way to create a regional market may provide incentives to cheat on the rules. We investigate the Nordic harmonization experiment with the price mechanism on the electricity spot market as a central coordination mechanism. Recent tendency in this market has raised concerns on the potential strategic manipulation of the congestion management rules. The industrial structures, market rules and regulatory models in the Nordic countries reinforce these concerns. We use a stylized numerical example that takes in account the main characteristics of the power flows equations on the grid to simulate market splitting and counter-trade, the two methods used to deal with congestions. We show that the difference in the distributive result of each method may give an incentive to fake a congestion on the grid so as to use a particular method rather than the other.

Keywords: Externalities, Regulatory authority, Electricity network
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[*] Université Paris I, Centre ATOM, 106-112 Boulevard de l'Hôpital, 75634 Paris Cedex 13, France ; ADIS, 54 boulevard Desgranges, 92331 Sceaux.
Tel: (+33) 1 44 07 83 21: Fax: (+33) 1 44 07 83 20, E-mail : vir_pignon@yahoo.fr

1. Introduction

During the last decade dramatic changes have taken place in the electric power sector. Competition has been introduced at the generation and supply levels. It has required the partition of previouly vertically and horizontally integrated organizational forms, the implementation of market-based governance structures and new arrangements between the de-integrated entities. The transmission and distribution grids are still considered as essential facilities that must now be properly regulated.

This move towards a competitive electric power industry has pointed out the importance of the congestions on the grid. Congestions may appear in some part of the electric power grid because of the limited capacity of the transmission lines that are not sized to transmit an infinite amount of electricity. They may substantially reduce the expected benefits from deregulation since they create local market power for incumbent generators physically isolated from potential competitors. But it is also more difficult to relieve the congestions in a deregulated environment compared with a monopolistic one. Indeed, the entry of competitors and the choice of supplier for the customers contribute to entail new patterns of electricity flows and thus more uncertainty in the management of the transmission network. Besides, the physics of the electricity flows makes some of the transmission services public goods and raises externality problems. The amount of electric power flow on a line depends indeed on the whole set of injections and withdrawals in the interconnected grid in real time! In a nutshell, the flows of electricity are governed by the Kirchhoff's laws that imply that they follow the lines with the least electrical resistance that is highly dependant on the transmission use in other parts of the grid. The physical paths of electric power are therefore disconnected from the contractual ones, raising negative as well as positive externalities among the users of the network. The arrival to the forefront of the electricity restructuring problems of the grid constraints has required the implementation of market-based congestion management methods in order to replace the closely coordination of transmission and generation that took place within vertically integrated monopolies.

An outstanding fact in deregulated electricity markets is that several methods are currently applied to deal with these network externalities, and different methods may even be simultaneously used in one common electric power market. That's the case in the Nordic electricity market. Norway, Sweden, Finland and Denmark have implemented one single non mandatory market but rely on two different methods to deal with congestions: Market splitting, for the congestions that appear at the borders between different control areas[1] and for some big and long-lasting bottlenecks internally in Norway, and counter-trading used for contraints in Sweden, Denmark, Finland and for smaller congestions in Norway. Both mechanisms lead to approximatively the same physical situation: consumption supplied

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[1] There are currently 5 control areas in the Nordic market, Norway, Sweden, Finland, East Denmark and West Denmark; each has its own transmussion operator that manages the use of the grid in the area.

with local generation in order to limit the use of the network. The main differences lie in fact in the trading processes and in the resulting financial flows.

The aim of this paper is to contribute to the discussions about the so called “seams issues” that arise when a regional energy market is based on several sub-markets. More precisely, we point out the incentives that the simultaneous use of different methods to deal with congestions may give. To this end, we first describe the Nordic Electricity Market, and more specifically Norway and Sweden. We point to some essential characteristics regarding the generation structures, the market rules as well the regulatory environment and show to what extent they contribute to the surge of a strategic behaviour by transmission system operator. Recent tendencies in the Nordic market reinforce the suspicion of strategic manipulation of congestions management rules.

We then simulate the congestion management mechanisms used with a simple, yet realistic, numerical example and compare them on the basis of the winners and losers that they entail. Even if we make the simplifying assumption that the users of the network don’t benefit from market power, these example enables to seize the distributional effect of each method and the consequences of the use of one specific method rather than the other for the market participants.

It will enable us to illustrate in the last part of the paper the use of a strategic behaviour, that consists in faking a transmission constraint on a transmission line. Faking a constraint entails the use of a specific congestion management mechanism that benefits to some market participants. This stylized example illustrates the recent trend in the Nordic electricity market.

2. Essential features of the Nordic Electricity sector

Norway is one of the first country that has deregulated its electricity industry in 1990. This competitive reform has in general been considered as a success and imitated in 1995 by Sweden. Both countries decided to extend the Norwegian market for physical trades of electric power to the Norwegian and Swedish interconnected area. One of the expected results was to increase the competitive pressure. Finland, West Denmark and East Denmark has joined the market respectively in 1998, 1999 and 2000.

First, it is worth considering the generation technologies and industrial structures after deregulation in the Nordic countries; it will be useful to lay down the assumptions of our simulations. We will then describe the organizational form of the common electric power market, NordPool, that is the essential coordination mechanism between the Nordic countries. It’s also the mechanism at the core of the congestion management. Nevertheless, the Nordic countries didn’t merge their electric power sectors and each area has its own transmission system operator regulated by a country specific regulatory body. It is an essential characteristic to investigate the opportunity of strategic behaviours.

2.1. Competitive reforms in the electric power industries

In each Nordic country, the deregulation model entailed the unbundling between grid operators, that have remained natural monopolies, and the generation and trading levels, where competition has been introduced. Nonetheless, most generators are also distributors and suppliers; the unbundling appears to be limited to the transmission level.

Compared with the reform in England and Wales, the deregulation in the Nordic countries didn't entail a big change in the industrial structures. For instance, the generation assets of the most important producers were neither shared among many generators nor were privatized. Statkraft, the biggest generators in Noway with 28 % of electric power generation, and Norsk Hydro (around 8 %) are state owned companies. In Sweden, Vattenfall is also wholly owned by the Swedish government; the Finnish government retains a majority stake in its biggest generator Fortum. The Swedish and Norwegian Transmission System operators, respectively Svenska Kraftnät and Statnett are also state owned.

To explain this maintaining of the industrial structure, one may put forward that the supply side was rather fragmented well before deregulation. Currently, at the Nordic level, none of the Norwegian generator has a market share that exceeds 10 % of the power sales in volume. However, the Swedish industry appears much more concentrated with 75 % of the Swedish production capacity that belong to Vatenfall and Sydkraft. Alone, Vatenfall produced 23 % of the Nordic electric power generation in 1999.

One of the aim of the implementation of the common Nordic market has been to benefit from the large differences in generation ressources. Indeed, the Norwegian generation capacity mix consists mostly of hydroelectric plants (for almost 99 %, concentrated in the North and the West of the country) and a marginal part of thermal plants. In contrast, the Swedish generation mix is more evenly distributed with a generation capacity mix of about 52 % of hydroelectric power, 30 % of nuclear power and 16 % of thermal power; most of the nuclear plants are located in the northern part of the country. Finland has also hydro, nuclear and thermal plants and Denmark has almost only thermal and wind power.

Table 1: Electricity generation and consumption within NordPool area in 1999

	Denmark	**Finland**	**Norway**	**Sweden**
Total Generation (GWh)	**37009**	**66766**	**122874**	**150510**
Hydropower (%)	0.08	18.88	99.37	46.79
Nuclear Power (%)	0	33.05	0	46.62
Other Thermal Power (%)	91.73	47.99	0.62	6.34
Wind Power (%)	8.19	0.08	0.01	0.25
Total Consumption (GWh)	**34844**	**77810**	**116516**	**141222**

Obviously these differences in the generation mix has an impact on the generation costs of electric power and on the competition in the area. The creation of the regional electricity market enables Denmark to benefit from cheap hydroelectric ressources whereas the Norwegian system may find here a protection against a huge increase in prices during dry years.

2.2. Organizational Form of the Nordic Electricity Market

Before being a regional electricity market, NordPool was primarily a Norwegian market created in 1992. Until 1996, foreign suppliers could compete in Norway but there were barriers to foreign participation in the market and broader transmission tariffs. The Danish, Finnish and Swedish areas are now integrated in NordPool, and there is no particular transmission tariff for transactions among the Nordic countries. Thus, NordPool seems to be completely open to trade across national borders; it currently covers 5 control areas, Norway, Sweden, Finland, East Denmark and West Denmark and potentially up to 8 congestion zones because Norway may be splitted in three zones when big internal congestions occur.

NordPool is a non mandatory electricity market where generators and consumers from the Nordic area bid prices and quantities of electric power for the next 24 hours; this market is cleared every day at noon and bidders are selected regarding the merit order[2]. Generators and consumers may also choose to trade through bilateral contracts, either directly or with brokers. Since its creation, the spot market gets more and more important. However, it is still the bilateral contracts that dominate the physical market. In 2000, 30 % only of the physical trades were spot[3] market trades through NordPool. The situations are quite different across the countries. The Norwegian transactions stand for 58 % of total physical trading on NordPool, but the Norwegian consumption just amounts to 31 % of the Nordic

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[2] We focus here on the physical trade and not on the financial one also managed by NordPool.

[3] Spot market is used to differenciate the day-ahead market, where electric power is traded between electric power generators and consumers for the day after, from the real time market, that mainly deals with unforseeable problems on the grid and eventually balances consumption and generation in real time.

consumption. In contrast, Sweden, which is the largest national market stands for 32 % only of total trading on NordPool. The shares of the Finnish and Danish transactions are even smaller.

In order to forecast the transmission of the energy sold, both through bilateral contracts and through the spot market, the sellers and buyers must specify day-ahead the congestion zone where their injection, or withdrawal point is located. These zones are regional zones that are delimited by the national borders and by two internal borders in Norway. Thus, generators annouce quantity and price and the congestion area where the generating unit is located. Inside each area, the self-dispatch mechanism prevails, that is to say the generators choose which plant to dispatch (provided that it is located in the announced congestion area) in order to meet their bilateral and market commitments.

Bilateral contracts across zonal borders aren't allowed. For such a transaction to be completed, the generator has to bid in the day-ahead physical market as a sale in the generation area and the consumer simultaneously bids as a purchase in the consumption zone. In other words NordPool has the monopoly for cross-border transactions among the congestion areas. Since 1996, Stratnett and Svenska Kraftnät, the Norwegian and Swedish transmission system operators are the two joint owners of NordPool. There are therefore tight relationships between the market operator, NordPool, and the grid operators.

One of the most salient feature of the Nordic market refers to the congestion management by the network operators. The Nordic operators have failed to agree on a unique mechanism: Market splitting is used to deal with the congestions that appear at the borders between the eight congestion areas whereas counter-trading manages congestions inside each area. These geographical borders should in principle be the places of the most severe bottlenecks, that is to say the interconnections between control areas. In the monopolistic environnement, the transmission grid has especially been developped on a national basis with some interconnections only built for security purposes. Besides, three areas have been delimited internally in Norway. Therefore, when Market splitting is used, NordPool, which is a common market, has several equilibrium prices for the same hour of the same day! It's a mechanism that creates several markets divided by congested paths. Hence we understand why the bids on the market have to inform of the location of the injection and withdrawal points among the congestion areas. But when market splitting is used, what appeared to be a rather competitive industry with a fragmented supply may in fact become highly concentrated.

2.3. Scope of the regulatory authorities

The deregulation of the electric power industry has led to the implementation of national regulatory authorities that have to control the deregulation process and the transmission system operator activity. Each control area has created its own regulatory authority[4] and the regulatory models implemented appear to be quite different among the Nordic countries. They range from a light-handed regulation in

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[4] Except in Denmark where there is a single regulatory authority for both control areas.

Sweden and Finland to a more heavy-handed regulation in Norway and Denmark. Thus, and despite the fact that the Nordic countries participate to the same market, the electric power industries have to comply with different rules.

In Norway, the decisions of NVE (Department of Water and Energy at the Ministry of Petroleum and Energy), the energy regulator, can only be reviewed by the Minister (the Minister is the appeal judge for NVE decisions); its tasks cover *inter alia* the generation and supply licenses and the control of the grid compagnies at the transmission and distribution levels. Concerning the grid, the transmission tariffs applied by each operator are regulated. These tariffs should cover the congestion costs but also the costs of infrastructure, of the losses[5] and of the ancillary services[6]. To control the level of the transmission tariffs, Norway has adopted a revenue cap regulation with financial rules for the transmission operator clearly determined *ex ante*. Thus, the grid operator is constrained by a maximum revenue, whose level is fixed by the regulatory authority, based on expectations regarding the evolution of its costs. Compared with other regulatory models, it should provide incentives for an efficient operation of the transmission grid, since the costs beyond what is allowed by the revenue cap won't be covered by the tariff. However, Norway has implemented limits for minimum and maximum rates of return that guarantee to a certain extent the viability of the grid operator and the price for the grid users. This kind of regulation implies a tight control from the regulatory authority on the grid company.

The Minister of Petroleum and Energy is the State Authority for energy public firms, that is to say for the network operator Statnett, the generators Statkraft, Norsk Hydro and Statoil. Simulateneously, the Independent Competition Authority has to control the market.

In Sweden, it is the Swedish National Energy Administration that regulates the electric power sector; it's an administrative authority whose "main duty is to implement the Swedish government's policy […]".[7] In addition the Agency has to ensure the efficient operation of the grid. The Swedish authority has adopted a more light-handed regulation, with an examination of the financial situation of the grid companies based on a case by case analysis. Besides, grid companies are regulated based on a rate of return and theirs goals are much less detailed than with a performance-based regulation like a revenue cap.

So far the Swedish approach has been characterized by investigations based only on complaints and not on a systematic review of the electric power industry. Since the beginning of the Swedish electricity deregulation, the regulatory authority "has not been very active in determining the rules of the game"[8]. Some essential criteria to properly assess the transmission activity haven't still been

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[5] Some power is lost during transmission due to the increase in the temperature of the transmission lines.

[6] These services mostly intend to meet technical requirements for the reliability of the grid (voltage and frequency regulations, spinning reserves…).

[7] The Swedish National Energy Administration website, http://www.stem.se.

[8] Helle Gronli, "A Comparison of Scandinavian Regulatory Models: Issues and Experience", *The Electricity Journal*, August-September 2001.

precisely defined. For instance, no clear indicator of the "fairness" of the transmission tariffs has been determined yet. As a comparison, the Finnish model appears to be more powerful with a regulatory authority that launches investigations on the basis of its own suspicions.

To sum up this point, the Norwegian[9] model is a "long lasting regulation", with a continuous control of the sector, whereas the Swedish regulation could be described as a "spot regulation", that is to say a case based investigation. The Danish regulation looks more like an in-between model.

An interesting point lies in the control of the transmission cross-border lines operation between the Nordic control areas. Let's take the example of the connection between Norway and Sweden. The two grid companies, Statnett and Svenska Kraftnät operate the cross-border lines, that are regarded as ordinary parts of the transmission grids. Therefore, each network operator has included its own share in the costs of the interconnectors in its ordinary transmission costs; the interconnection costs are investigated as the normal transmission costs and the cross-border lines are subject to the usual regulation of each country. The costs and revenues of the transmission lines between Norway and Sweden are thus regulated by two different authorities that differ concerning the regulatory models that they use.

3. Congestions Management Mechanisms Comparison

We now introduce the two congestion management methods used in the Nordic countries, market splitting and counter-trading. We will develop a simplified numerical example, taking in account the main features of Kirchhoff's laws, to illustrate their trading processes.

3.1. Market-splitting versus counter-trading

Market splitting and counter-trading, even if they have the same ultimate goal, entail different trading processes. Nevertheless, the first stage is the same; it consists of clearing the day-ahead spot market on the basis of the supply and demand bids while ignoring the transmission capacity constraints. It results in the system price.

Then, the resulting flows of electric power are simulated and if the market results overload the transmission lines, market splitting entails the partition of nodes into different areas on either side of the bottleneck. New market prices are determined, one for each area, taking in account the initial bids on the day-ahead market and the transfer capacity between the zones. Net transmission over the zone-boundary should be fixed in order to meet the capacity limit. Considering the case of two zones and compared with the unconstrained system price, market splitting results in a higher price in the area with a deficit of cheap generation and a lower price in the area with a surplus. Hence, the congestion costs are directly charged to the network users through the difference in zonal market prices for

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[9] The Finnish regulatory model is similar.

electric power. The market operator, that is the monopoly for the cross-border transactions “buy” power at the level equal to the capacity limit in the low price area and “sell” it in the high price area.

The principle of counter-trading is a buy-back principle which consists in replacing the generation of one generator “ill-placed” on the grid as regards the congestion by the generation of one “better-placed” producer. Rather than modifying the unconstrained equilibrium in quantity and price of the day-ahead spot market, the buy-back principle is implemented through another voluntary market where generators bid for increases or decreases in their day-ahead generation schedule. In Sweden, consumers also are allowed to bid on this market; nevertheless; their participation appears to be very low. The sole buyer is the transmission network operator, that bears directly the costs of increasing and reducing generation. These costs are then charged to the network users through the transmission tariff.

3.2. Network simulations

We simulate the two trading processes on a stylized example, that illustrates the Norwegian and Swedish interconnection, and compare these mechanisms as regards their financial impact on the market participants. We assume a linear lossless “DC”[10] approximation of the power flow equations, which enables to focus on real power only and to take in account that the flows don’t follow the contractual path between generation and consumption. Hence, we will simulate the externality pattern of electric power due to the Kirchhoff’s laws and isolate its effect on a grid with limited capacity.

Three main laws are used here to model electric power network. They are essential to understand the relationships between injections and withdrawals on the one hand and the power flows over the lines on the other hand. First, the Kirchhoff’s current law that shows that the net injection[11] in a node is equal to the current flowing out of it on each line that is directly connected to it. Second, the Kirchhoff’s loop law that implies that the sum of the potential differences across all components around any cycle in a grid is zero. And third, the law of the conservation of energy that implies that total generation is equal to total consumption and losses.[12]The flows on the grid are mainly governed by these laws. They imply that as soon as we consider more than one line connecting two nodes, an injection of electric power in a node will be spread on each line of the interconnected grid depending on the injection and withdrawal patterns in the other nodes.

The network considered consists of 8 nodes, 4 located in market N and 4 located in market S. There are 3 cross-border lines. Each node is consumer and simultaneously supplier of electric power. For the sake of simplicity we assume linear supply and demand curves. Demand in node i is given by

$$p_i = a_i - b_i q_i^d$$

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[10] The “Direct Current” approximation of the power flows equations is frequently used when analyzing congestion constraints; it enables to get linear equations.

[11] That is the difference between the current injected and the current withdrawn at the node.

[12] The constraints of the maximization program in the case of our simulations are displayed in appendix.

and supply in node i is given by

$$p_i = c_i q_i^s$$

where p_i is the price in node i, a_i, b_i and c_i are positive constants.

We attempt to reflect the main demand and cost features of the Swedish and Norwegian systems. We have already noticed that Norway is mainly hydroelectric with the biggest units located in the North and in the West. Some thermal plants are located in the South East of the country. In Sweden, the big nuclear power plants are mostly in the North. Non surprisingly, the short term variable costs, that is to say the operation, maintenance and fuel variable costs, of hydro generation are closed to zero. Depending on the specific fuel considered, the thermal variable costs estimates for the Nordic countries are going from 6 times up to 20 or even 25 times the hydro power variable costs! The variable costs of nuclear power are estimated to be around 3 times those of hydroelectric power.

As for the main features of consumption, most of electricity consumption in Norway and Sweden is concentrated in the South and center of each country.

Table 2: Costs and demand parameters

Node	Generation	Consumption	
	c_i	a_i	b_i
1	0,8	20	0,02
2	0,1	20	0,05
3	0,5	20	0,1
4	0,1	20	0,25
5	0,9	20	0,02
6	0,7	20	0,05
7	0,3	20	0,02
8	0,2	20	0,25

The region's baseload production is mainly supplied by hydro and nuclear plants whereas the thermal plants with relatively high fuel costs serve the peak and winter demand. We should notice that a precise assessment of the generation costs of electric power is a hard task because it implies to consider the start-up costs, the no load costs, the ramping rates… that also contribute to assess the productive efficiency of a generation unit.

The first step of the simulation consists in computing the market equilibrium that maximizes the total social surplus, computed as the sum of the nodal social surplus revealed by the demand and supply bids, while taking in account the Kirchhoff's laws and the law of the conservation of energy. At this stage, we don't consider the capacity constraints of the grid.

The result is the following unconstrained dispatch[13].

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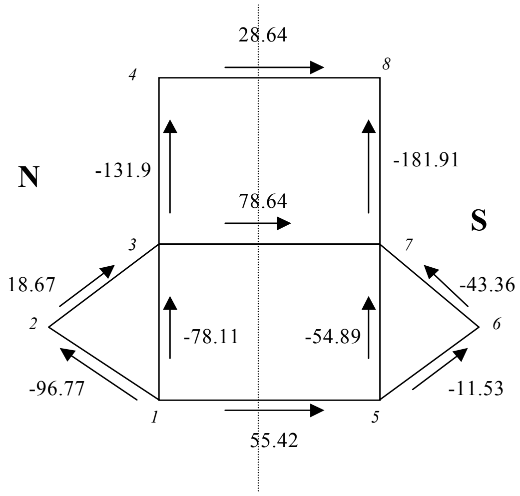
[13] Throughout this paper, the arrows on the figures go from the lower to a higher node number ; a negative number next to an arrow means that the electricity flows in the opposite direction.

Figure 1: Unconstrained Dispatch



Node	Price	Generation	Consumption
1	17,18	21,48	140,93
2	17,18	171,81	56,37
3	17,18	34,36	28,19
4	17,18	171,81	11,27
5	17,18	19,09	140,93
6	17,18	24,54	56,37
7	17,18	57,27	140,93
8	17,18	85,91	11,28

Let us consider a capacity limit of 30 units on line (3,7). Hence, the flows resulting from the spot market clearing entail a binding transmission constraint and a congestion management mechanism has to be used.

This network represents in fact two potential submarkets N (nodes 1, 2, 3 and 4) and S (nodes 5, 6, 7, and 8), linked by three crossborder lines, (1,5), (3,7) and (4,8). With Market splitting, the congestion on the cross-border line (3,7) entails the partition of the market in two submarkets. We assume in this example that the boundary between the zones vertically cuts the lines (1,5), (3,7) and (4,8). Thus, and as in practical implementations, the nodes at the endpoints of the transmission constraint are allocated to different areas[14].

In the simulation program, we put a capacity limit of 30 units on line (3,7) and compute the optimal constrained dispatch of generation units; it gives the generation dispatch that maximizes the social surplus revealed through the bids of the market participants and that doesn't violate the transmission constraint. The two markets are cleared separately taking in account that the maximum flow of electric power through line (3,7) is 30 units.

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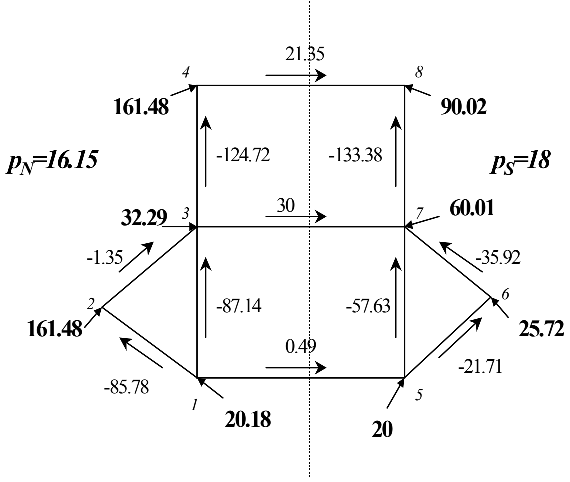
[14] Bjorndal et al. [2001] have shown that this implementation isn't always optimal when we take into account several congested lines.

Figure 2: Market Splitting



	Area N	Area S
Price	16,15	18,05
Generation	375,43	195,75
Consumption	323,6	247,58

The generation for each node is displayed in bold on figure 2.

Compared with the unconstrained dispatch, the implementation of two zonal markets with a limited cross-border transmission capacity on one of the linking lines leads to a lower market price for electric power in area N and on the contrary to a higher price in area S. It eventually entails a decrease of generation in market N, respectively an increase in market S, and an increase in consumption in market N, respectively a decrease in S.

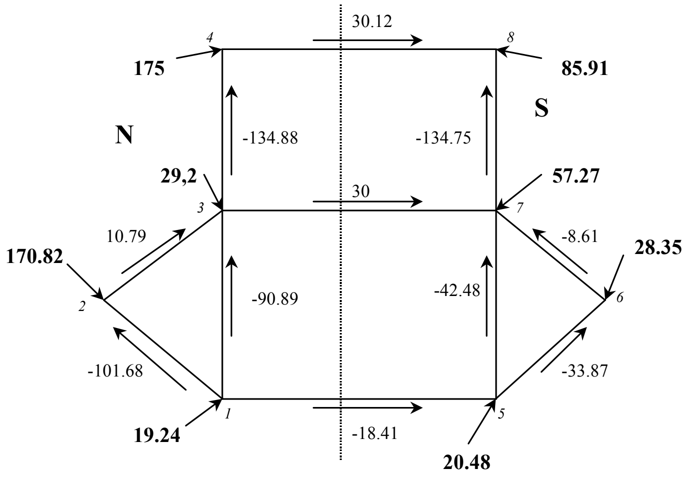
Let us now consider that in order to deal with the congestion on line (3,7), we use a mechanism similar to counter-trading. As explained before, this mechanism entails the implementation of an adjustment market, where generators bid for increases or decreases in their generation schedules resulting from the spot market. Obviously, this market gives a second opportunity to the generators to bid strategically, for instance to offer prices that are higher than their marginal costs. Nevertheless, and as we did in the case of the spot market, we don't consider here this kind of strategic behaviour.

Adjusting its generation level a few hours before delivery isn't costsless for a producer and these costs are all the higher as the generation technology isn't flexible. Therefore, it will be easier for a thermal plant than for a nuclear one. A hydroelectric plant presents another kind of problem that mainly refers to water storage . As we have mentioned before, the precise assessment of every component of the cost function of an electric power producer is a difficult task. Hence, we take into account this flexibility in a rather crude but also quite simple way: we make the assumption that some generators don't take part in the adjustment market, in particular the nuclear power stations. The generation levels are fixed in nodes 7 and 8 at their unconstrained levels; besides a generation capacity limit is fixed at 175 units in node 4, that is a big energy provider at the unconstrained stage.

As for the consumers, they may be allowed to participate in the adjustment market, as it's the case in the Swedish market, but the practical experience show that their participation is very low. In the short term, the price sensibility of electric power demand is almost zero. Therefore in our simplified example, the consumption level is considered to be fixed to the level resulting from the unconstrained dispatch and has to be met whatever the problems on the grid.

With counter-trading, the network operator pays for the increases in generation and is paid for the decreases in generation as compared with the unconstrained equilibrium. Because of the rules applied to fix the prices on the adjustment market, the marginal bid, and of the lack of flexibility of some low-cost generation technologies[15], it results in congestion costs for the grid operator even if we consider that the generators truthfully reveal their costs. The goal in the adjustment market is therefore to minimize the costs resulting from the generation adjustments, while respecting the transmission capacity limit and meeting the consumption level that results from the spot market. It gives the following flows and productions on the grid.

Figure 3: counter-trading



The final generation for each node is represented in bold on figure 3.

With this congestion management method, the generation pattern has changed compared with the market splitting solution.

Table 3: Generation Dispatch according to the Congestion Management Method

Node	Market Splitting	Counter-trading
1	20,18	19,24
2	161,48	170,82
3	32,29	29,2
4	161,48	175
5	20	20,48
6	25,72	28,35
7	60,01	57,27
8	90,02	85,91

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[15] In particular, the nuclear one.

As for the prices, Market Splitting entails two zonal prices, 16.15 in region N and 18.05 in region S, which are used to price every megawatt of energy sold during one hour. Generators are paid and consumers are charged with one of these prices according to their localisation on the grid. With counter-trading, it's the market clearing price, resulting from the spot market, that is used to pay producers and charge consumers. But, in addition the generators that are retained to increase their generation on the basis of their bids on the adjustment market are paid for the additional output the marginal price for an upward adjustment. This price is the bid of the most expensive generator retained in the adjustment market. Simultaneously, a few generators are selected to "buy back" some of their generation, that is to say to decrease their production compared with spot market result. These generators have to pay the marginal price for a downward adjustment, that is to say the bid of the less expensive generator retained in the adjustment market. Considering the price bids of generators without market power, we get the following equilibrium prices on the adjustment market.

Table 4: Equilibrium Prices on the Adjustment Market

Upward Price	Downward Price
19,85	14,6

The additional units sold after the spot market clearing are paid the upward price and the downward generators eventually pay some of their units back at the downward price.

As we have already noticed, counter-trading entails costs for the transmission system operator that has to pay the additional units and gets money from the buy-back units.

In our example, it results in a cost equal to:

$\text{TSOcosts} = (G_{AU} - G_{SU}) * p_{AU} - (G_{SD} - G_{AD}) * p_{AD} = 43.99$

where G_{AU} is the adjusted generation level for upward generators

G_{SU} is the spot generation level for upward generators

p_{AU} is the market price for upward adjustment

G_{SD} is the spot generation level for downward generators

G_{AD} is the adjusted generation level for downward generators

and p_{AD} is the market price for downward adjustment.

On the contrary with Market splitting, the grid operator doesn't pay for generation adjustment; the market operator, that belongs to the Norwegian and Swedish transmission operators, has the monopoly over the cross-border flows. He buys the exported units in the low price area, transmit them and sell them in the high price area. Eventually, it leads to the following benefit:

$\text{TSOben} = CBF * (p_{HZ} - p_{LZ}) = 96.16$

where CBF stands for the net amount of cross-border flows,

p_{HZ} and p_{LZ} are respctively the energy price for the high price are and for the low price area.

At the same time, the final generation profit appears to be highly dependant on the congestion management method used, even if we assume that the generators really bid at their marginal costs.

Table 5 displays the generation surplus, computed for each node in the case without congestion, with a congestion dealt with through market splitting and eventually with a congestion dealt with through counter-trading.

Table 5: Generators Profit Comparison

Node	Unconstrained Dispatch	Market Splitting	Counter-trading
1	184,49	162,97	188,26
2	1475,93	1303,79	1478,44
3	295,19	260,76	301,84
4	1475,93	1303,79	1483,92
5	163,99	180,06	166,83
6	210,85	231,51	215,91
7	491,98	540,18	491,98
8	737,97	810,27	737,97

Since the counter-trading approach entails generation adjustments for some price-taker generators and doesn't interfere with the unconstrained price results, the profits in the unconstrained dispatch and counter-trading cases are rather similar. But we should in addition take in account that the costs resulting from counter-trading for the grid operator are eventually charged to the grid users through the regulated transmission tariff. The network operator recovers the congestion costs with a uniform charge per unit injected or withdrawn from the grid[16].

Table 6: Generators profit with counter-trading including the congestion charge

Node	Final Profit
1	187,53
2	1471,95
3	300,73
4	1477,27
5	166,05
6	214,84
7	489,80
8	734,70

Obviously, the choice of the congestion management method isn't neutral at all with relative variations of surplus due to the change from market splitting to counter-trading that may amount to more than 15 % in nodes 1 and 3.

As for the consumer, the sole difference between the unconstrained and the counter-trading cases lies in our simple example in the congestion costs charged through the transmission tariff. Nonetheless, they are greatly impacted by market splitting since the price they have to pay for their electricity ranges from 18 in market S to 16.15 in market N.

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[16] Uniform means here that the congestion costs charged through the tariff are the averaged costs of the whole control area. Yet the allocation of these costs to the consumers and generators may be different from one area to another; for instance, Statnett allocates 50 % of its costs to the consumers and 50 % to the generators whereas Svenska Kraftnät allocated almost 2/3 of its costs to the producers. Here we have considered a 50% - 50% allocation.

The illustration of these congestion management mechanisms enable us to point out the distributional consequences that result from the choice of one method rather than the other. Pointing to the differences in the trading processes and their distributional results however underlines the potential benefits for some market participants to adopt an opportunistic behaviour and cheat on the rules.

4. Strategic Behaviour

The simultaneous implementation of the different congestion management methods in a single market may give incentives to adopt an opportunistic behaviour and cheat on the rules. These incentives should be all the higher that the financial consequences at stake are noticeable. We focus on one particular strategy that consists in faking a constraint on a given transmission line. In particular, we show that when he faces a congestion, the network operator may prefer faking and resolving a fictitious constraint so that he also manages the real one… but changes at the same time the relative balance between the winners and losers in the market.

At least two groups may have the ability to fake a constraint in the Nordic electricity market:

- the transmission grid operator, that fix the capacity limit of the lines on the grid and because of the high level of externalities in the electric power grid, these limits are determined on the basis of reference cases[17], that let a high degree of liberty; let's recall that the regulatory models in the Nordic countries aren't equally constraining…
- the generators also since they can benefit from the self-dispatch rule and from the location of their generating units on the grid to trigger congestion on specific transmission lines.

We will focus here on the first case.

4.1. Towards a diverted congestion management

The congestion management methods used in the Nordic countries tend to be more and more debated. Indeed, zonal prices has frequently diverged often these last years which raises concerns on potential market power and opportunism especially from the Swedish industry; as we have already noticed, it's indeed the most concentrated generation system in the Nordic market coupled with a passive regulatory authority. These last years, the separation between the Swedish and Norwegian prices has happened almost half of the time! Besides, the gap between the zonal prices has greatly increased. A study[18] based on NordPool data, reports that Sweden in 1998 had an averaged zonal price just a bit lower than the system price (- 2 %); in 1999, the zonal price was around 1 % higher and in 2000, 12 % higher than the unconstrained system price! At the opposite, the Norwegian areas had in 2000 a lower price, ranging from – 2 % to – 6 %. Some have argued that it could be due to specific hydro

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[17] The publications on the website of the European Transmission System Operators enable to have a look on the high variability level in the transfer capacity asessments http://www.etso-net.org.

[18] "European Power Trading 2001", Prospex Research Ltd.

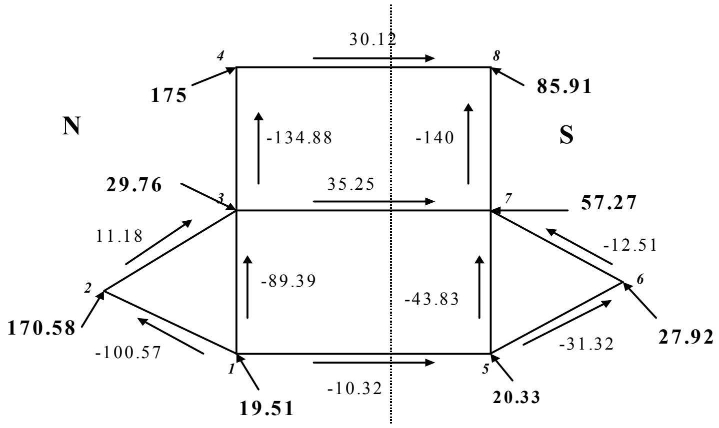
conditions, and the issue of wether it could be a manipulation of the rules to deal with congestions or not hasn't been settled yet.

We will now illustrate a strategic behaviour that could explain this frequent divide. It consists in cheating on the congestion management rules through the fake of congestions on specific transmission lines.

Let's return to the previous numerical example. In this case, the least cost generation dispatch while ignoring the capacity limits on the grid brought about a flow of 78.64 units from node 3 to node 7. We assumed a transmission capacity limit of 30 units only.

Let's now consider the case where the real transmission constraint lies in fact on line (7,8) and not on line (3,7). In the unconstrained case, 181.91 units would flow from 8 to 7 whereas the maximum energy flow that can be transmitted amounts to 140 units. Since the congestion appears internally in market S, the counter-trading method should be used. Considering the same assumptions as in the previous counter-trading example, the management of the constraint on line (7,8) gives the following flows and injections at each node.

Figure 4: counter-trading with constraint on (7,8)



Relieving the congestion through counter-trading entails costs for the transmission system operator that has to buy additional units at the upward price and to sell back units at the downward price, namely 19.54 and 14.88 respectively.

$TSOcosts = (G_{AU} - G_{SU})*p_{AU} - (G_{SD} - G_{AD})*p_{AD} = 36.34$

We consider the previous assumptions as regards the market power of the generators; in particular we consider that they bid at their marginal costs on the markets and that the producers that take part in the adjustment market announce the same costs as in the spot market. To take in account the lack of flexibility of the nuclear producers, the generators located at nodes 7 and 8 don't participate to the congestion management. Hence, they have to generate at their unconstrained level. We also assume a generation capacity limit of 175 units for the generator located in node 4.

The producers at nodes 1,2 and 3 eventually decrease their output compared with the unconstrained level whereas on the contrary the producers at nodes 4,5 and 6 increase their output. The least cost adjustment of generation to manage the congestion entails the dispatch of the most efficient units taking in account the generation and the transmission costs[19]. Since the adjustment market clears at the marginal price, even without power market, most of the producers will eventually benefit from the congestion management. Nonetheless, the transmission cost operator integrates uniformly their congestion management costs in the transmission price.

Table 7: Generators Profit with counter-trading including the congestion charge

node	Final Profit
1	186,87
2	1 473,40
3	299,56
4	1 477,52
5	165,60
6	213,96
7	490,20
8	735,30

It's interesting to notice that with the market splitting solution computed before, only 133.38 units are flowing from node 8 to node 7. Thus, putting a capacity limit of 30 units on line (3,7) eventually solves the internal constraint in market S! Besides, line (3,7) is a cross-border line and the market splitting mechanism is used to deal with the bidding constraint on cross-border lines. Hence "moving" the transmission constraint on the cross-border line (3,7) may relieve the internal congestion on line (7,8) without having to resort to counter-trading.

4.2. Winners and Losers

Market splitting and counter-trading are two congestion management methods that are quite different as regards their trading process and the distributional consequences that they have. The more different these consequences will be and the higher the incentives to cheat on the rules will be.

Based on this stylized example, some market participants may have an interest in faking a constraint on line (3,7).

Firstly, the system operator extracts revenues from the crossborder transactions and the zonal price difference. Since the bilateral contracts aren't allowed between different control areas, every cross-border transaction takes place through NordPool, that belongs to the Transmission System Operators. They transmit power from the low market price area to the the high market price area while respecting the transmission capacity limit. In the numerical example previously developped, market splitting resulted in an additional revenue that amounts to 96.16 monetary units.

Secondly, table 7 show the relative variation of surplus for each generator due to the use of market splitting instead of counter-trading, that is to say due to the fake of a cross-border constraint.

Table 8: Relative variation of profit for the generators

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[19] However the sole transmission costs considered in this paper are the costs due to the congestions on the grid.

Node	Surplus Variation
1	-12,79%
2	-11,51%
3	-12,95%
4	-11,76%
5	8,73%
6	8,20%
7	10,20%
8	10,20%

The increase in profits for the generators located in area S ranges from 8.20 to 10.20 % when the congestion is managed with the market splitting mechanism instead of counter-trading. In the mature electric power industry, as it is the case at least in the developped countries, it's a variation that is worth considering! Obviously, the generators located in area N are in the opposite situation with for some of them a loss of profit that amounts to more than 12 %.

We have described and illustrated two congestion management mechanisms that differ as regards the level of internalization of the externalities on electric power networks: non-existent with the counter-trading mechanism that uniformly charges the average congestion costs to the grid users, partial in the case of market splitting with a unifom price charged within each area but different prices across areas. The simultaneous use of both mechanisms may trigger a opportunistic behaviour in order to benefit from the financial consequences of one of the mechanisms. It consists in faking a constraint on a specific line.

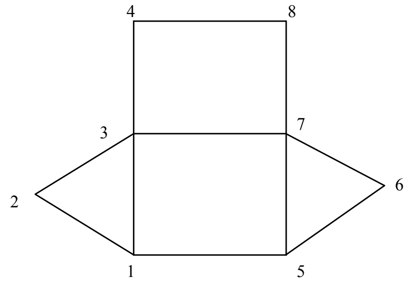
5. Conclusion

This paper raises a problem linked with the creation of common regional electricity markets based on several submarkets, each having its own transmission rules. We focus here on the interaction between the congestion management methods used in the Nordic market and point out a strategic behaviour rooted in the difference in the distributional results of the method used. Even if we assume that the generators on the markets bid their generation marginal costs, we indeed find in the numerical example developped that the choice of the congestion management method isn't neutral regarding the financial situation of the market participants. That is because of the different internalization level of the externalities on electric power networks. It brings about distributional conflicts that may give an incentive to manipulate the rules. The example of manipulation investigated here may be an explanation for the recent tendency in the Nordic electricity market.

Currently, the creation in Europe and in the United States of regional energy markets raises several debates as regards the "best" harmonization way between the submarkets. At the core of this debate lies the following question: should we favour a regional coordination between control areas or the creation of one single area with uniform rules? In Europe as well as in the United States, it seems that up to now we have bet on the first solution, although there are noticeable differences between the American and European methods. However, one of keys for this choice to be successful lies in the compatibility level between the subregional rules. It may be that as regard the congestion management methods, the competitive and distributional effects at stake are too large to enable the simultaneous use of several mechanisms.

Appendix: Modelling of the power flow equations

In the optimization programs, the Kirchhoff's current and voltage laws as well as the law of conservation of energy appear as constraints to take in account the power flow equations that govern the way electric power is transmitted in the grid.



In the 8 nodes electric power grid example, it gives the following constraints:

Kirchhoff's current law

$X_1 = X_{12}+X_{13}+X_{15}$

$X_2 = X_{21}+X_{23}$

$X_3 = X_{31}+X_{32}+X_{34}+X_{37}$

$X_4 = X_{43}+X_{48}$

$X_5 = X_{51}+X_{56}+X_{57}$

$X_6 = X_{65}+X_{67}$

$X_7 = X_{75}+X_{76}+X_{78}$

Kirchhoff's voltage law

$X_{13}-X_{12}-X_{23} = 0$

$X_{57}-X_{56}-X_{67} = 0$

$X_{13}+X_{37}-X_{15}-X_{57} = 0$

$X_{34}+X_{48}-X_{37}-X_{78} = 0$

law of conservation of energy

$$\sum_i X_i = \sum_i (G_i - D_i) = 0$$

where

X_i is the net injection (positive or negative) for node i,

X_{ij} stands for the electric power flow on the line that connects node i to node j,

G_i is the power generation in node i,

and D_i is the power consumption in node i.

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