Do energy markets provide adequate incentives for investment in generating capacity? – A case study in Nordic electricity market

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Abstract—**This article provides an insight into the profitability of a peak load generator in the Nordic electricity market as a way to evaluate the market's capacity to provide adequate incentives to stimulate investment in generating capacity. We base this analysis on the Nordic electricity market during the very tight period of the winter 2002-2003 triggered by an extreme drought, which should represent one of the most favorable market conditions to remunerate a peaking unit. The result shows that the "missing money" problem exists in the Nordic wholesale electricity market. Tracing the sources of the revenue gap, we find that the Nordic countries' peak load arrangement might be a major reason for the depression of price in the real time market and consequently in the spot market. After having studied the peak-load reserve arrangement, the real-time market design, as well as Nordic system operators' inclination in terms of market development, we propose some market design remedies which could help reinforce the consistency of market rules and the credibility of market prices.**

***Key words*— capacity payment, energy market, missing money, peaking units' profitability**

I. Introduction

Until 1990s, electricity sectors almost everywhere in the world were operated by vertically integrated national monopolies. Since then, a liberalization process has been taken place in many countries which mainly involves complete unbundling of the competitive activities (production, trading and supply) from the network activities (transport and distribution), and creation of competitive wholesale markets. In theory, the price signals generated by a competitive wholesale market are supposed to reflect the scarcity of the generation resources, and thus are able to induce the right amount of generating capacity (associated to a certain level of reliability required) by providing a scarcity rent just equal to the capital cost of the marginal generators. However, in reality, the wholesale markets suffer a number of demand-side and supply-side flaws[1] that make them deviate from the perfect functioning models. That's why after several years of liberalization experience, overriding concerns have been raised on the aptitude of a competitive electricity market to ensure an adequate level of reliability of supply by stimulating new investments in generating capacity. Such concerns are not groundless. A serious problem that has been exhibited on many organized electricity markets is the "missing money" phenomenon, referring to the fact that spot wholesale electricity market prices for energy and operating reserves are simply not high enough to provide sufficient scarcity rent to remunerate existing power plants or to attract new investment. Such problem has been observed in many U.S. electricity markets over several years time [1]. Our objective is to analyse the situation in the Nordic electricity market, which is often named as an energy only market without explicit capacity payment arrangement and is generally considered as the most developed power market in Europe.

The methodology we adopted to evaluate the incentive provided by energy markets to stimulate investment is similar to the one practised by PJM Regional Transmission Organisation [2], which consists in calculating the net revenue that a hypothetical new combustion turbine (CT) would have earned on the wholesale energy market supposing a perfect foresight of market price and an optimal dispatch[2]. This methodology, which we will present in the section III, is independent of the power mix of an electricity market.

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[1] The demand-side flaws and supply-side flaws that impede the perfect functioning of electricity market have been explained by Joskow [1], Tirole [3, 4] and Stoft [5]. The demand curve does not necessarily reflect the real utility that consumers attach to the volume of electricity consumed because it is impossible to date to meter the individual consumption of each consumer, or to control the power flows to specific consumers. On the other hand, the supply curve may also be distorted by the imposition of price caps and by the system operator's interventions during scarcity hours which are aimed at avoiding curtailment of demand or high prices. Another non-negligible imperfection of the real electricity market lies in the implicit belief that the government will ultimately intervene to guarantee the reliability of supply as long as the slogan "keep the lights on" prevails. Such implicit belief can be reflected by the lack of risk management and improper distribution of risk among actors in the electric system, as what we will show in the last part of this article.

[2] The perfect dispatch supposes that a unit can be readily dispatched when the market price exceeds its marginal cost regardless operating constraint. So the net revenue calculated under perfect dispatch should represent an upper bound of the net revenue that the generator can earn in the market.

However, our methodology is different from that of PJM in four aspects: 1) we calculate only the net revenue of a peaking unit such as CT to measure the overall market performance. In an optimal power mix, all supply technologies require scarcity rent during the "shortage hours" to cover the capital costs. In particular, the recover of capital cost for the peaking technology depends almost on the scarcity rent only. That is why a peaking unit such as combustion turbine often serves as a touchstone to test whether wholesale markets provide adequate incentives for investment in generating capacity; 2) the period of investigation is the tight period of winter 2002-2003, rather than 8 consecutive years as in PJM' analysis. The Nordic power market exhibits a strong hydraulic periodicity. The winter 2002-2003 is characterized by a severe drought which had induced tight market conditions during several months, in contrast with quite smooth price pattern in other normal years. Hence, we can consider that the winter 2002-2003 represents one of the most favourable market conditions for the remuneration of a peaking unit. If a peaking unit cannot be fully remunerated during this period, there is little chance that it could break-even during "normal" years. 3) PJM obtains the marginal cost of CT by simply adding the fuel cost and variable operation and maintenance cost. This is a common simplification of the start-up decision for a generator. However, in practice, the generator may have to take the starting-up cost into account (unit commitment decision), which is especially true for a peaking and flexible unit for which the number of start-up is quite important compared to base-load or intermediate producing unit. In our calculation, we use the cost data published by the French Minister of Financial and Industrial Economics in 2003, in which the start-up cost is included and spread in the variable cost. And finally 4) our calculation of revenue does not include the income from the supply of ancillary service such as reactive power because of lack of public data.

The article is structured as following: the first part provides an overview of the Nordic electricity market. The second part presents the calculation of the profitability of a peaking unit on the Nordic spot market during the winter 2002-2003. The result of the calculation entails an in-depth investigation of the peak load arrangement in Nordic countries. Finally, some comments and propositions are made for the improvement of Nordic electricity market's functioning.

II. Presentation of Nordic electricity market

During the 1990s, after the deregulation of their electricity sector, Norway, Sweden, Finland and Denmark have created a common Nordic electricity market. They share a common exchange of electricity, Nord Pool, which is composed of a day-ahead market, Elspot, an intra-daily market Elbas and a financial market. The Elspot day-ahead market is the most liquid market in Europe, with an exchange volume of around 260 TWh/year. On the contrary, the size of Elbas intra-daily market is very limited, with an exchange volume around 1 TWh/year [6]. System operators in each Nordic country are in charge of the real-time equilibrium of supply and demand in the whole area of the Nordic electricity market by operating jointly a real-time power market (RPM).

The annual electricity consumption in Nordic market is around 400 TWh, about half of which is supplied by hydroelectricity. Because of the dominance of hydropower, the electricity price in Nord Pool is greatly influenced by the seasonality of hydro resources. A shortage of hydropower due to the climate factors can provoke a severe supply shock, which tends to last for quite a long time until the next round of filling up of reservoir. Therefore, the depth and duration of the supply shock should entail a corresponding high price level in the market, which is nevertheless favourable to the remuneration of peaking units. The winter 2002-2003 represents just such a tight market condition, where an unexpected lack of rainfall in autumn caused a reduction of 35 TWh of hydraulic power compared to normal level [7]. Consequently, the price began to rise from October 2002 and peaked at 123 €/MWh in Februry 2003, whereas the average price in 2002 was only 27 €/MWh.

III. Numerical example: profitability of a peaking unit in Nord Pool

A. *Selection of price for calculation*

As presented above, the Nordic electricity market consists of several physical markets. On Elspot day-ahead market, hourly power contracts are traded for physical delivery in the next day's 24-hour period. For each hour, a system price is generated by the intersection of supply curve and demand curve disregarding the transmission grid. But if congestion is detected, area prices[3] are established by the mechanism of market splitting to relieve the bottlenecks and serve as prices for financial settlement of the transactions. As the time span between the Elspot price fixing and the actual delivery hour of the concluded contract can be quite long (12-36 hours), the market participants may still need to adjust their portfolio before the physical delivery of energy. The intra-daily Elbas market is just created for this purpose of allowing bilateral exchanges of energy up to one hour prior to delivery. On Elbas, the price is fixed between two counterparts by the mechanism of "pay as bid". Finally, a real time regulating power market is conducted jointly by the Nordic system operators to ensure the real-time balancing of injection and withdraws of energy. In the real-time market, TSOs procure upward regulation in case of deficit of power, and downwards regulation in case of surplus of power. The regulating power price is set at the marginal bid. Our observation of these prices in the aforementioned markets during 2002-2003 can suggest us the following:

[3] For the period 2002-2003, there were 8 bidding areas in the Nordic exchange area: 5 in Norway (Bergen, Oslo, Tromso, Kristiansand, and Trondheim), 1 in Finland (Helsinki), 1 in Denmark (Odense) and 1 in Sweden (Stockholm)

- the area prices were closely correlated to the system price, except for Denmark
- the maximum prices in Elbas intra-daily market were much higher and more volatile than the Elspot system price, although the average Elbas price followed generally the same evolution as the system price
- The real-time prices were very closely correlated to the system price but with fewer peaks. There is no connection between the direction and the volume of regulation and the level of system price. The difference between upward regulating power price and the system price turned out to be minor during the tight period of winter.

For these reasons, we decided to use the Elspot system price and Elbas intra-daily price to calculate the revenue that a peaking unit can earn in the Nordic electricity market.

B. Calculation of profitability of a peaking unit in the Nordic market during winter 2002-2003

A typical peaking unit is an open cycle combustion turbine. We refer to the report "Reference cost of electricity production" [8] published by the French Minister of Financial and Industrial Economics in 2003 for the cost structure of the combustion turbine, as we did not find out any detailed cost data of electricity production in Nordic countries. Table 1 displays the cost components of a typical CT for a running time of about 500 hours per year[4]. By subtracting the investment cost and fixed O&M cost from the total cost, we can obtain the variable cost of the CT. In order to simulate a perfect dispatching, we suppose that the CT is started up once the market price is higher than its variable cost which is 77 €/MWh .

As illustrated by Figure 1, the winter 2002-2003 encompassed almost all the price peaks during the year 2002 and 2003. Supposing all these price peaks happened during one whole year, we can draw a price duration curve which can tell us the net revenue that the combustion turbine can earn by cutting the curve by its variable cost (See Figure 2). We can then measure to which extent the net revenue contribute to recover the fixed cost of the combustion turbine.

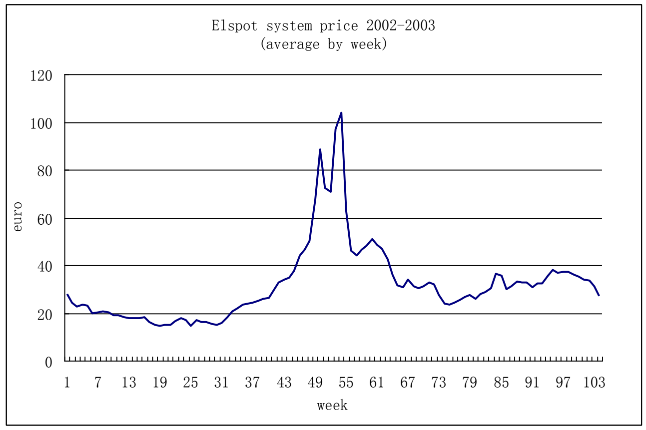
[4] In fact, the total cost per MWh of the combustion turbine varies for different duration of running, because the starting up cost is spread in the total cost in a non-linear way. The report of DGEMP 2003 provides the cost data for a running time of 250, 500, 1000, 1500, 2000, 2500, 3000 hours per year. We select the variable cost for 500 hours' running time (77 €/MWh) to simulate an optimal dispatch mainly for three reasons: 1) a combustion turbine is generally not supposed to run for 1000 hours or more during a year; 2) according to the report of DGEMP, for a running time of 250 hours per year, the variable cost of the combustion turbine is as high as 104 €/MWh. However, such variable cost will imply very few running hours of the CT given the price level in the Nordic electricity market. The net revenue generated during these few hours is far from sufficient to recover its fixed cost; 3) if the combustion turbine is started up once the price outstrips 77 €/MWh, we can find that the running time of the combustion turbine (supposing a perfect price foresight and a perfect dispatch) is just in the neighborhood of 500 hours, which can justify our hypothesis of the variable cost of the combustion turbine in the context of Nordic electricity market.

Table 1: Cost structure of combustion turbine
Reference of installation: 300 MW; life time: 25 year; discount rate: 8%; gas price: 3.3 $/MBtu; exchange rate: 1 €/$

Duration of running	(hour/ year)	500
Total cost per MWh	(€/MWh)	160
Annualised total cost	(€/MW/year)	*80 000*
Annualised investment cost	(€/MW/year)	*28 500*
Annualised O&M cost and taxes	(€/MW/year)	*13 000*
Annualised variable cost	(€/MW/year)	*38 500*
Variable cost per MWh	(€/MWh)	77

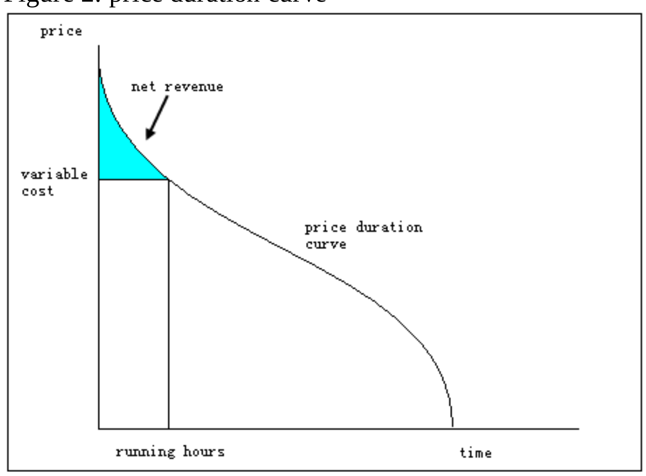
Source: DGEMP 2003 [8]

Figure 1: Elspot system price during 2002-2003



Source of data: Nordel

Figure 2: price duration curve



The results of the profitability of the CT in Elspot and Elbas market are displayed in the Table 2.

Table 2: Profitability in Elspot and Elbas market

Starting up at 77 €/MWh	Elspot	Elbas
Running hours	443	512
Revenue €/MW/an	40 161	49 377
Net revenue €/MW/an	6 050	9 953
Total fixed cost €/MW/an	41 500	41 500
Coverage of fixed cost	15 %	24%
Missing money €/MW/an	35 450	31 547

According to the results, neither of the two markets provides sufficient revenue to remunerate the combustion turbine; about 76% to 85% of the fixed cost remains uncovered. The performance in the Elbas intra-daily market is slightly better than in the Elspot market. But we should keep in mind that exchange volume in the Elbas market is very limited: it was only 0.6 TWh in 2006 and 0.7 TWh in 2007; more precisely, during the winter 2002-2003, the average exchange volume in Elbas when price was above 70 €/MWh was around 100 MWh/h. Therefore, we can grossly approximate the revenue earned by the CT to the revenue earned on Elspot market, which means that the CT could cover only about 15 % of its fixed cost even in a year characterized by extremely tight market conditions, the missing money being around the amount of 30000 €/MW/year, equivalent to about 80% of the capital cost of the combustion turbine. It is then safe to conclude that it is hard for the peaking unit to cover its investment cost during its life time by selling energy on the Nordic wholesale electricity market. Note that the net revenue is calculated *ex post* supposing a perfect foresight of market price. In reality, the uncertainty of the market condition would further increase the likelihood that no investment at all occurs.

C. Analysis of the results

The results show that even in the "best year", there was a big revenue gap for the CT in the Nordic market, not to mention other "average" years during its life time. Hereafter, we simulate two theoretical scenarios of spot price that could allow the full remuneration of the CT.

Scenario 1 with higher prices during the tight period: during the 443 hours' running time of the CT, if the price could reach 264 €/MWh (instead of 123 €/MWh in reality) from 77 €/MWh with a constant increasing rate on the price duration curve, the fixed cost of the combustion turbine could be just covered. (Net revenue= [(264-77) €/MWh*443h /2]/year = 41500€/year = fixed cost)

Scenario 2 with application of price cap[5] during the tight period: if the price cap of 1250 €/MWh can be applied for 35 hours[6], the fixed cost of the combustion turbine can be just covered. (Net revenue= [(1250-77) €/MWh*35 h]/year = 41500€/year = fixed cost)

In comparison with the two theoretical scenarios, the real Elspot price during the winter 2002-2003 has neither reached the high level we assumed in the first scenario, nor been set at the price cap even once. The fact that the price cap had never been reached shows among other things that the price cap was not a binding constraint in the spot market We have noticed that in spite of a relatively high degree of demand response in the Nordic countries compared with other European countries [9], the market conditions remained very tight during the winter 2002-2003, as suggested by a series of media campaign launched by public authorities to call on people to rationalise their consumption of electricity during that period. In our opinion, the most influential factor on the price level in Nordic market relies on the peak load arrangements which are implemented and operated by the national system operators. The next section of the paper is dedicated to a detailed investigation of the peak load arrangements in Nordic countries and their impact on market functioning.

IV. Peak load arrangements

The peak load problem refers to the situation where the demand is so high that the generating resources in the market may not be sufficient to satisfy it. Although the system operators in Nordic countries agree on the principle that the market should be designed to solve the peak load problem, in practice, each system operator has its own peak load arrangements which often involve subsidies for some generating resources in or outside the market.

In Norway, the system operator Statnett has implemented since 2000 an innovative disposition called RCOM (regulating capacity option market) to secure an adequate volume of regulating resources in the real-time market as a way to solve the peak load problem[7] [10]-[11]. In this market, Statnett buys the options from the supply side as well as the demand side. The sellers of the option receive a prime fixed by the marginal offer retained and in exchange, they are committed to submit bids in the real time regulating market for the volume contracted during the defined period but with no restriction on price. The volume of options that Statnett procures in this market is variable according to its prevision of market

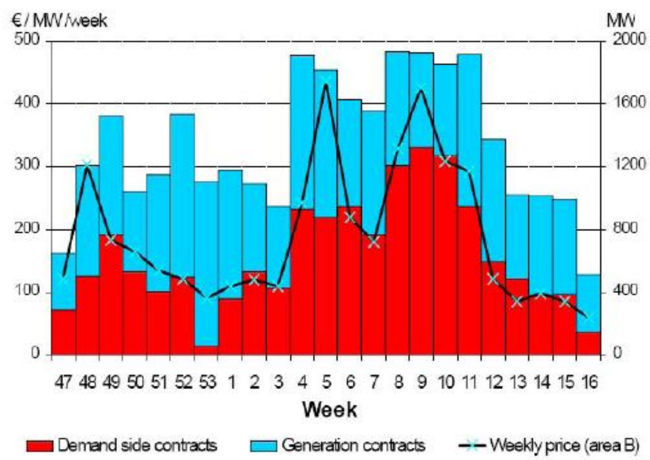
[5] Here, "shortage price" should be a more appropriate term than "price cap", for that price cap is fixed in the aim of limiting the spot price to rise above it, whereas the spot price is driven automatically to the "shortage price" once a certain level of tension of supply and demand is perceived. This type of practice is often named as "scarcity pricing", while the definition of "scarcity" may vary from one system operator to another. However, we maintain the term "price cap" because the "shortage price" is usually fixed as equal to the price cap.

[6] According to a report of Eltra (TSO of western Denmark) in 2003 [9], the price cap was fixed at 10 000 NOK/MWh during the winter in the spot market (100 NOK ≈ 12.5€). We can see from the result that a low level of price cap corresponds to a long duration of application time (or a high loss of load probability, LOLP) in order to remunerate a peaking unit.

[7] In the end of 2006, Statnett also bought 300 MW of mobile production units from Pratt & Whitney to handle the temporary deficit of production in winter [6].

condition. As a consequence, the price of the option also changes from period to period (cf. Figure 3). In Sweden, the system operator SvK signs bilateral contracts with producers (often mothballed thermal plants) and large consumers for their commitment of ensuring the availability of peak load reserve during the winter in exchange of a prime [12]. During the rest of year, the producer is free to sell the energy on the market, but 80% of the profit is transferred to SvK as a contribution to the financing of peak load reserve. Besides, SvK also purchased generating capacity for the reason of security of supply during peaking hours. For example, as ordered by the Government, SvK purchased in January 2002 a 500 MW power reserve to be used if periods of extreme cold weather arose. For the winter 2002-2003 they bought a reserve of about 450 MW [13]. In Finland, the system operator Fingrid pays a compensation for the return to service of mothballed condensing power plant during winter. Fingrid also has its own generating capacity via purchase or lease of power plant. In Denmark, the system operator Energinet.DK contracted bilaterally with producers for the provision of regulating power during hard winter [14].

Figure 3: volume and prices on RCOM, winter 2004/2005



Source: Statnett

These peak load arrangements are basically equivalent to capacity payments for peak load producers or non-market generating resources in exchange of their commitment of supplying regulating reserve when needed. One direct outcome of such peak load arrangements is that they provide another source of income for peak load units. The result of our calculation has shown that, in order to fully bridge the revenue gap, a supplement revenue should be equal to about 80% of the capital cost of the CT. Due to the lack of relevant data for the year 2002 and 2003, we cannot know exactly the amount of the additional payment for peak load producers and to which extent it filled in the revenue gap. The only available price concerning the peak load arrangement is the RCOM weekly price during the winter 2004/2005, as presented by Figure 3. A preliminary calculation shows that the income generated by RCOM during the winter 2004/2005 only covers one third of the revenue gap that the combustion turbine experienced during the winter 2002/2003[8]. A more precise estimate of the RCOM revenue should be done when more data is available in the future.

However, while the peak load arrangements can have the effect of reducing the short-term revenue deficit of the peak load producers, they can also interfere with the normal functioning of the market and depress the price, which in turn undermines the interest of all producers, including the peak load producers. Due to the existence of the additional payment that flexible generators and consumers receive from the system operators, the upwards regulating price in the real time market does not reflect the total cost of providing regulating energy, which can partly explain why the upwards regulating price in the real-time market was only slightly higher than the spot price. Nevertheless, as the real-time regulating market is the last market place where the market participants can sell and buy energy, it caps the prices in the Elbas and Elspot price. In this way, the Elbas and Elspot prices are also depressed, which further compresses the revenue of all producing units. Moreover, the call for the return to service of some mothballed power plant [9] and introduction of non market producing resources (units owned by system operator) during the peak time can seriously distort the real relationship of supply and demand in the market, and prevents the price to rise to a higher level which should reflect the scarcity of producing resources in the market. Finally, it is worth noting that only the peak load producers that contractualize with the system operator in the framework of such arrangements can receive the supplementary payment. This may induce a “sitting on the fence” strategy for the potential investors in peak generating capacity who will not invest until they are ensured of being included in the peak load arrangements. In one word, the peak load arrangements can have the effect of ensuring the short-term security of supply without unfavourable high prices, but at the same time they jeopardize the functioning of the market to pilot the long term investment by sending correct price signals.

V. Proposition of Market Design

In order to reduce the negative effects of the peak load arrangements on the functioning of the market, the Nordic system operators have agreed on the principle that the Nordic electricity market should be designed to solve peak load problems, and interventions in the market should be avoided. Guidelines for the harmonisation of peak load arrangements have been published by Nordel in 2007 which specifies the

[8] Revenue from RCOM during the winter 2004/2005 was 4310 €/MW for 23 weeks. We can take the average remuneration for the 23 weeks to get the yearly revenue offered by RCOM, which is 9744 €/MW/year. Revenue gap for the combustion turbine is estimated in the order of 30000 €/MW/year. So the income generated by RCOM can cover more or less one third of the revenue gap.

[9] According to the annual report of SvK, the Sweden system operator, some mothballed power plant had returned to service during the winter period with high prices. In Finland, a law that came into force on 15 December 2006 implied that the mothballed condensing power plant be dedicated to guarantee the power supply during the peaking period from the beginning of 2007.

rules concerning the procurement and activation of peak load reserves [15]. According to the new rules, the peak load resource should be offered first in the Elspot market, and then Elbas market. Finally, all remaining available resources can be offered in the real time regulating market. The resource shall only be used after all commercial bids have been activated. The activation of peak load reserve in Elspot market will lead the market price directly to its maximum level, which is equivalent to 2000 €/MWh according to the existing rules. In Elbas and RPM, the bid price should be equal or higher than the max price in Elspot[10]. The sprit of such rules is to prevent the use of peak load resource to distort the merit order and suppress the market price by forcing the price to reach the maximum level to mimic the situation of a real shortage of energy, while no forced load shedding is actually taking place. Such practices echo with the proposition of Oren [16] and Joskow [1] to make price caps meaningful by hitting them during scarcity conditions. Nordel gives a clear definition of the “scarcity conditions”, which refers to the period during which the peak load resources are activated. At the same time, the max price in Elspot will serve as the minimum price in Elbas and real-time regulating market, which ensures the coherence of price signals and allows the scarcity of resources to be fully expressed in these two markets.

If the 2007 rules are effectively implemented, they could kill two birds with one stone: protect the consumers from blackouts on the one hand, and improve the functioning of the electricity markets on the other hand. However, the demand side participants in the spot market may be averse to such rules for that once the scarcity pricing is activated, they have to pay very expensive for the energy. In fact, the ultimate solution of the missing money problem for the generators is a transfer of capital from the demand side to the supply side. The aversion of demand side participants to extremely high price may reduce the liquidity of spot market to some extent. Every coin has two sides. The aversion to high price in the spot market may also help to cultivate a proper demand side risk management, and more importantly, to stimulate a highly reactive demand response in order to avoid as much as possible the situation where the system operators have to set the price in their place. As Stoft has pointed out [5], a small amount of elastic demand can make the market efficient. We can then achieve a functioning energy market with few price spikes but longer duration of high prices, as described in the Scenario 1 that we have simulated, which is beneficial for both of the producers and the consumers. Of course, the credibility and effectiveness of these rules is still waiting to be tested, maybe in the next round of shortage of energy due to the drought, as the market price has never reached the price cap until now. However, while waiting for the real test of the 2007 rules, we should anticipate the interactions of these rules with existing markets rules, and see carefully whether the latter is compatible with or would weaken the effect of the former.

As presented above, the Nordic countries have generally implemented different peak load arrangements that offer the suppliers a complementary payment for the commitment of bidding in the real time regulating power market. If the 2007 rules are credible, the suppliers of regulating power can be remunerated at a price at least equivalent to 2000 €/MWh once the peak load resource is activated,. But at the same time, they receive also the capacity payment via the mechanism such as RCOM. Thus, the peaking units tend to be over-remunerated compared with other producers which contribute to the security of supply at the same time. In this sense, the co-existence of the 2007 rules on the peak load arrangement and the actual “capacity payment” mechanism for regulating power suppliers, can once again send distorted signals which can over-boost the investment in peaking units.

Another preoccupation stems from the actual rules concerning the financial security that the balance responsible market participant is required to provide to the system operator for the access to the organised wholesale market of electricity. In theory, the financial security should be evaluated as the price of real-time regulating power multiplied by the volume of electricity transacted in order to fully cover the risk of non-payment of a market participant. In Nordic countries, each national system operator has its own rule about the calculation of the security required. The security can be indexed to the price of the futures in the precedent month, as in the case of Denmark [17], or to the average spot price in the precedent month, as in the case of Finland [18]. The security calculated in these two ways is obviously not sufficient as a hedge against the risk of non-payment of the market participant in case of high price in the market. In Norway, the fixation of the security is much closer to the theoretical model. The security required is equivalent to the average price in the real-time regulating power market in the precedent week [19]. However, there is an exoneration clause exempting the national or municipal power companies from the requirement of security. From a market participant’s point of view, such fixation of security can be interpreted as that the system operator does not anticipate extremely high price in the market, otherwise the system operator would not let himself exposed to the counterparty risk which could be potentially very high. In this sense, the stipulation of security deposit implies an implicit guarantee of spot price so that the market participants can readily free themselves from hedging the risk of volatility of price. In order to convince the market participants of the credibility of the 2007 rules (application of price cap once the peak load resources are activated), the system operators should revise their formula of security and help to prompt a proper sense of risk among the market participants.

[10] The application of these pricing rules is less obvious given the “pay-as-bid” mechanism in Elbas market.

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