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THE NORDIC MARKET: SIGNS OF STRESS?

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The supply shock that hit the Nordic electricity market in 2002-2003 put the market to a severe test. A sharp reduction in inflow to hydro reservoirs during the normally wet months of late autumn pushed electricity prices to unprecedented levels. We take this event as the starting point for analysing some potential weaknesses of the Nordic market. We conclude that fears regarding supply security and adequacy are likely to be unfounded. Nevertheless, as inherited over-capacity is eroded, and new market-based environmental regulation takes effect, tighter market conditions are to be expected. It is then crucial that retail markets are fully developed so as to allow consumers to adequately protect themselves from occurrences of price spikes.

INTRODUCTION

The Nordic electricity market – encompassing Denmark, Finland, Norway and Sweden[1] – is well established by now. Starting in Norway in 1991, regulatory reform gradually spread to Sweden (1996), Finland (1997) and Denmark (2002). In all countries, separation of competitive and monopolistic activities, establishment of independent TSOs and allowing consumers to choose their supplier have been integral parts of reform. With a long tradition of Nordic co-operation, and with development of the jointly-owned power exchange Nord Pool, the Nordic market is now *de facto* fully integrated, at least at the wholesale level.

In this paper, we analyse some issues that are currently high on the agenda in the Nordic countries. Space does not allow a full discussion of the developments of the Nordic market, nor a comprehensive analysis of its functioning.[2] Instead, we limit our attention to a few important issues that have arisen lately, partly as a result of the extreme events of 2002-3.

[1] The fifth Nordic country – Iceland – is not interconnected with the others. The term ”Scandinavia” is inappropriate, as it only encompasses Denmark, Norway and Sweden.

[2] See for instance Bergman et al (1999) for a more comprehensive discussion of the earlier developments of the Nordic market.

In the second half of 2002, inflow to hydro reservoirs was only 54 per cent of the average of the preceding 20 year period (Bye, Hansen and Aune, 2003). As a result, reservoir fillings were record low at the beginning of the low-inflow/high-demand winter season. Foreseeing tighter market conditions, suppliers began restricting supply in late autumn and prices started to rise. The (daily average) spot price peaked at 850 NOK/MWh in January 2003, two to three times the normal level. High spot prices feed through to consumers, who in some cases faced increases in electricity bills of 50 per cent or more.[3] There was speculation that high prices were the result of abuse of market power, as well as a lack of investment in both generation and transmission in earlier years, and that rationing on a massive scale would be required. As it turned out, no such drastic measures were warranted, as responses from consumers and thermal-power producers balanced the market. Even though prices remained high during most of 2003, market conditions gradually normalised.

Some saw the events of 2002-3 as a warning sign, or indeed as outright proof that the electricity market is flawed. Others consider its performance through this period as evidence that the market has reached maturity and is robust enough to withstand even quite extreme shocks. We tend to lean towards the latter view. Nevertheless, the supply shock brought to the surface a number of potential weaknesses that warrant careful analysis and which may eventually lead to further improvements in the regulatory framework as well as in other market institutions.

After describing the events of 2002-3 in some detail, we analyse two issues that have attracted considerable attention in the aftermath of these events. The first issue concerns the operation of the retail market; in particular, whether there is sufficient competition on the market, and whether current contractual arrangements are adequate for consumer needs. The second issue concerns generation and transmission capacity; in particular, whether sufficient investment is forthcoming and reasonable levels of supply security and adequacy may be maintained. We end the paper with a discussion of how the implementation of the Kyoto protocol may affect the Nordic electricity market.

COPING WITH A SUPPLY SHOCK[4]

The development of the electricity market during the winter of 2002-2003 was spectacular, with prices reaching unprecedented levels and a constant threat – according to some observers – of rationing on a massive scale. We concentrate our attention on events in the Norwegian segment of the market, where effects were at their most extreme.

[3] Note that, since many Nordic consumers rely on electricity for most domestic energy needs, incl. heating, electricity bills tend to make up a considerable share of household budgets. For a typical Norwegian household, annual electricity consumption is around 20 MWh (compared to an average of 3.6 MWh in Britain), while the annual bill would amount to around NOK 14,000 (approx. Euro 1,700) at a price of 250 NOK/MWh.

[4] This section draws extensively on Bye, von der Fehr, Riis and Sørgard (2003); see also Bye (2003), Bye and Bergh (2003) and Bye, Hansen and Aune (2003).

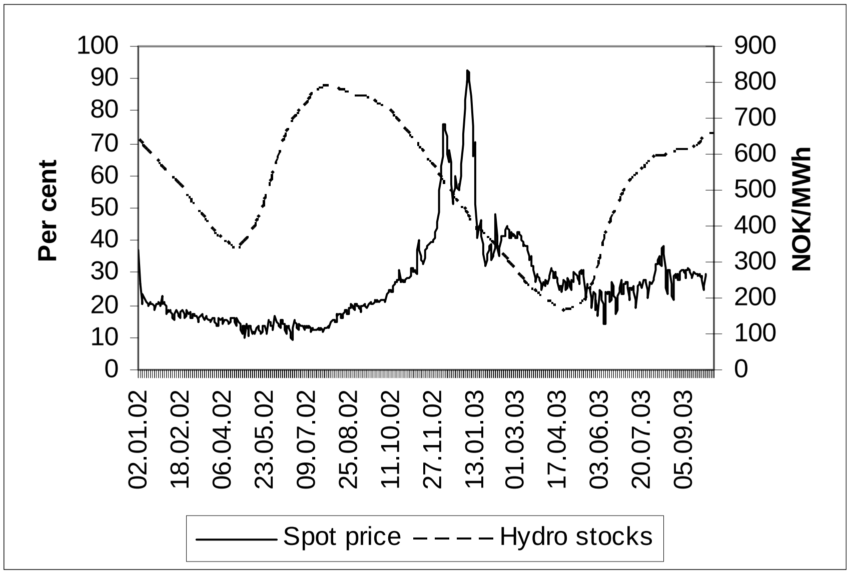

Figure 1: Spot price and Norwegian hydro stock, 2002-2003 (source: Statistics Norway and Norwegian Water and Energy Authorities)

Figure 1 shows the Nord Pool spot price (daily average) and the level of Norwegian hydro stocks[5] from the beginning of 2002 to the end of the summer of 2003. From a low level during the summer of 2002, the spot price rose gradually during the early autumn. This is normal and reflects the fact that limited storage capacity makes it impossible to transfer sufficient water into the high-demand/low-inflow winter season to equate prices over the year. However, towards the end of the autumn the spot price rose steeply and continued to rise well into the winter, when it peaked at around 850 NOK/kWh. The spot price then fell during the late winter and spring, but remained relatively high during most of 2003.

The price development reflects the development of hydro stocks. Stocks fell from high levels in the summer of 2002 to record low levels in the following winter. The most obvious reason for this unusual development was the extremely dry hydrological conditions with an almost total stop in inflows to reservoir during the normally wet weeks of the late autumn.[6]

[5] The Nordic hydro generation capacity is almost entirely located in Norway and Sweden. The Swedish hydro stocks followed a parallel development to the Norwegian.

[6] Inflow to reservoirs is at its minimum in the winter season when most precipitation is in the form of snow, and it reaches its maximum in the late spring and early summer when the snow melts. Autumn is usually rather wet, with almost all precipitation in the form of rain, and hence inflow is relatively high in this period also.

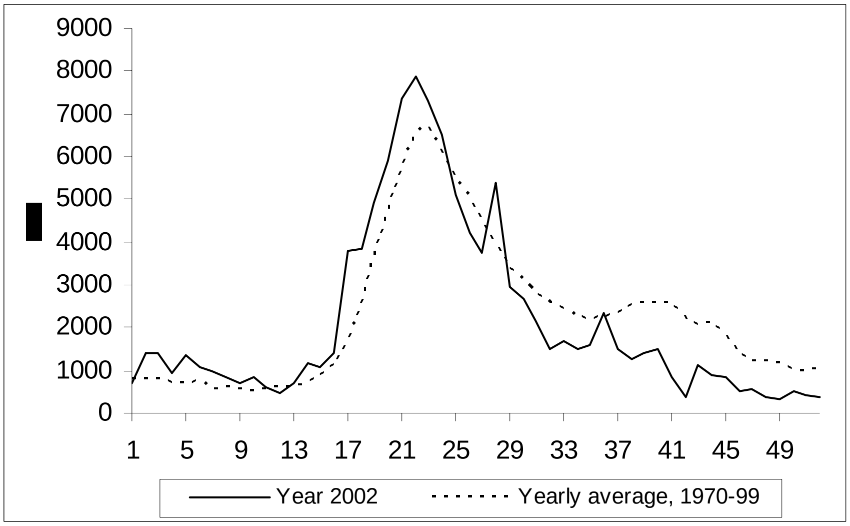

Figure 2: Weekly inflow to Norwegian hydro reservoirs (Source: Norwegian Water and Energy Authority)

As shown in Figure 2 – which compares weekly inflow to Norwegian hydro reservoirs during 2002 with yearly averages over the period 1970-99 – the year 2002 actually started out as rather wet. Until the summer, inflow was consistently above the historical average; indeed, in the 24 first weeks of 2002 inflow was 14 TWh, or nearly 20 per cent, above average. However, in early autumn inflow fell below normal levels and from October onwards it more or less dried up completely; during Weeks 38-48 inflow was 9,3 TWh below average.

It has been argued that the fall in hydro stocks could have been avoided if generators had restricted supply at an earlier stage. However, with the very high levels of stocks in the early autumn there was apparently a real risk that – with a wet autumn – reservoirs would have become so full that water would have been lost.

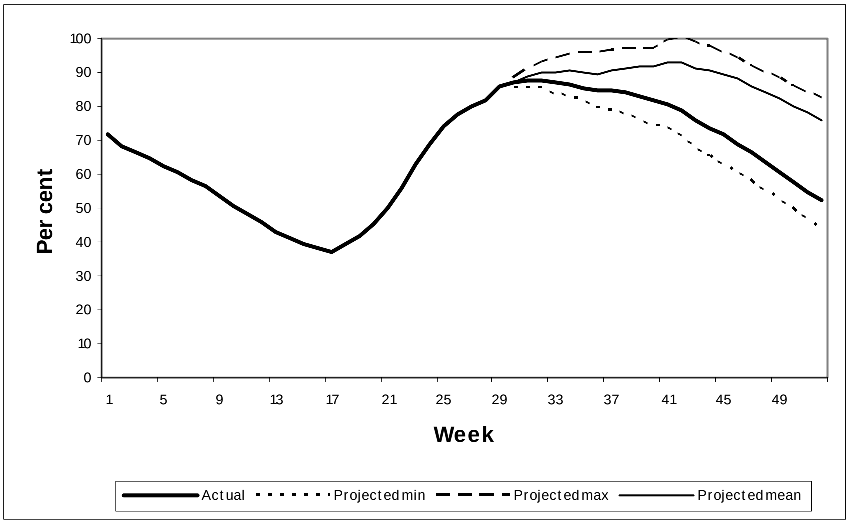

Figure 3: Norwegian hydro stocks 2002, actual and projected from Week 30 (source: Statistics Norway and Norwegian Water and Energy Authorities)

Figure 3 shows actual total hydro stocks, as well as projected levels as seen from Week 30. With maximum inflow reservoirs would have become completely full. Given differing levels of stocks, inflow patterns and constraints on output, the risk that any individual reservoir would be filled up was likely to be higher than suggested by these figures. As it turned out, such a wet outcome did not occur; instead, inflow and hydro stocks were in fact close to the lowest projected level.

This evidence would seem to be consistent with a view that generators acted rationally upon information available at the time. On the other hand, the evidence is also consistent with the view that hydro generators were overly anxious to tap their reservoirs, possibly with the intention of pushing up prices, which, at the time, looked to remain at modest levels during the winter. In any case, the mere suspicion that such anti-competitive practices were pursued may well have been influential in determining the tough stance that the Norwegian government took on attempts by the dominant (and state-owned) generator Statkraft to buy up more of its smaller Norwegian rivals.

Another possible explanation for the price spike – popular among a number of commentators – was that a lack of investment over a long period of time had eventually lead to under-capacity and a consequent imbalance between supply and demand. It is certainly true that investment levels had been low for a number of years, but whether this was a sign of market imperfection is questionable. We discuss the investment issue in some detail below. Here we only point to the fact that even though prices reached record levels during 2002-2003, they had been well below levels that would make new investment profitable for most of the preceding 10-15 years. Forward contract prices were also low. For instance, in 1999 prices in forward contracts covering the year 2002 were around 150 NOK/MWh, well below the 200 NOK/MWh estimate at the time of unit costs for new gas-fired plants. Forward prices gradually increased in subsequent years, although in 2002 prices covering the year 2006 were still not higher than 180 NOK/MWh. There consequently seems to be little support for the view that generators had not seized on profitable investment opportunities.

A criticism along similar lines concerned investment in transmission capacity.[7] Some commentators argued that lack of investment in transmission capacity – both within and between the Nordic countries – had allowed the development of areas where severe shortages were bound to arise. Again, it is true that there had been relatively little investment in transmission capacity over a number of years, and that the 2002 supply shock lead to long periods of time in which the market was effectively segmented. In particular, import-capacity to Norway, and export capacities from the thermal-dominated systems in Denmark and Finland, were constrained during much of the winter of 2002-2003. Nevertheless, it is not clear that this was a sign of deficiencies in the transmission network. On the one hand, the Nordic countries are highly interconnected, and most of the time the market is fully integrated at a single market-wide price. On the other hand, bottlenecks are becoming more frequent, and, in combination with increasing levels of market concentration, there is a worry that the result may be imperfect competition and inefficient market outcomes. We return to this latter issue below. We also return to the issue of transmission investment in connection with our discussion of supply security and adequacy.

[7] A completely opposite, but nevertheless quite popular view was that high prices in Norway were caused by excessive interconnection with neighbouring countries, leading to a drain on hydro resources and consequent shortage prices. While there was certainly some truth in this view, it seemed to overlook the fact that in the face of a severe, negative supply shock prices would reach even higher levels without access to imports. We do not discuss the possible (protectionist) implications of this view.

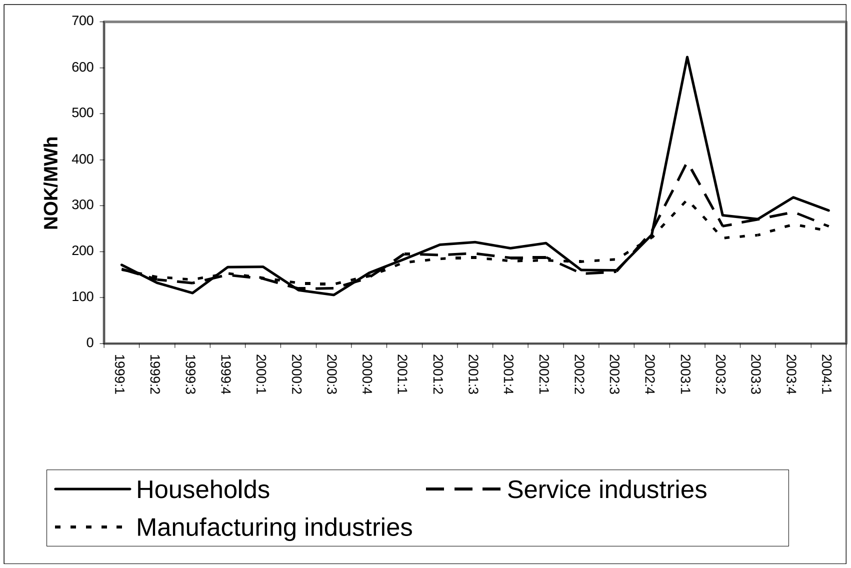

Figure 4: End-user prices (excl. taxes and network tariffs), quarterly observations, 1999-2004 (source: Statistics Norway)

The high spot prices feed through to end-user prices. Figure 4 shows quarterly observations of average retail prices from early 1999 to early 2004 for households, services industries and manufacturing industries, respectively. Retail prices shot up at the end of 2002 and soon reached unprecedented levels. Prices paid by households tended to increase more than those paid by industrial consumers. The difference seems to be explained by the different composition of contracts in the various segments of the market. Most household consumers have so-called “variable-price contracts”, according to which retailers can change the price with a few weeks notice. As of the first quarter of 2003, 85 per cent of household consumers had such contracts; another 7 per cent were on spot-price contracts (with the retail price directly linked to the Nord Pool spot price) and only 8 per cent on fixed-price contracts (see Figure 5). This is different from industrial consumers, especially in the manufacturing industries, who tend to rely more on long-term, fixed-price contracts. In the first quarter of 2003, 55 per cent of consumers in the manufacturing industries and 22 per cent of consumers in service industries had fixed-price contracts. The corresponding figures for spot-price contracts were 35 and 53 per cent, and for variable-price contracts 10 and 24 per cent. Consequently, industrial consumers were less exposed to price increases than were households.

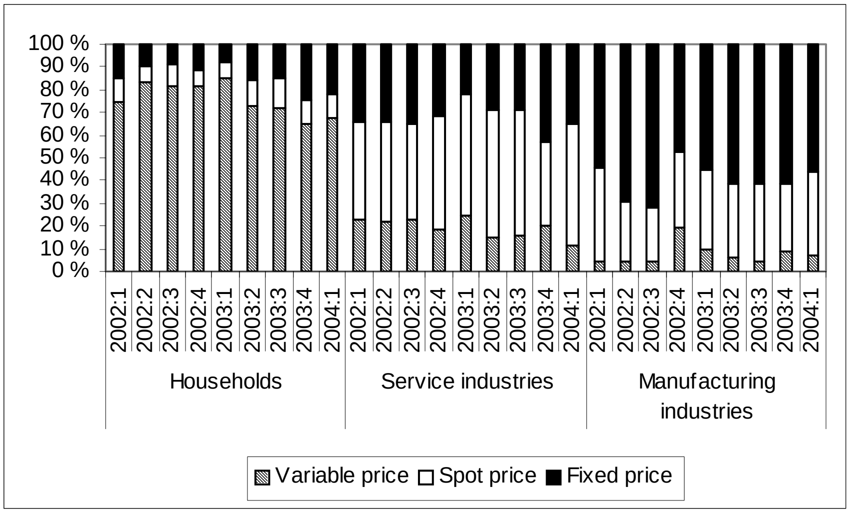

Figure 5: Contract shares, quarterly observations (source: Statistics Norway)

There was a general move from variable-price contracts to fixed-price contracts in the wake of the events of the winter of 2003. This trend seems now to be reversed (maybe because the memory of the price spike is starting to fade?). Interestingly, there is little interest among household consumers – as opposed to industrial consumers – for so-called "spot-price" contracts, in which the retail price is linked to (an average of) the Nord Pool Elspot price. There is ample evidence that spot-price contracts perform consistently better than variable-price contracts in the longer term; in particular, it would seem that competition between suppliers of variable-price contracts is not always entirely effective. The reason households have not embraced spot-price contracts may be (an erroneous) view that these contracts, being linked to the highly variable spot price, are somehow more risky than variable-price contracts.

Increases in end-user prices had a considerable impact on demand. Roughly speaking, demand may be seen as consisting of three segments: the very flexible boiler segment (approx. 5% of the total), the heavily-contracted power-intensive industry (approx. 30%) and the rest (approx. 65%). Demand from the boiler segment – which can easily switch between oil and electricity – fell sharply when prices started to rise in October 2002 and remained low during the winter; all in all, electricity consumption by boilers over the period November 2002 to May 2003 was around one third of that of the corresponding period in 2001-2002. In the energy-intensive industries, some plants stopped production, but the overall response was relatively small, probably less than 5 per cent (Bye, von der Fehr, Riis and Sørgard, 2003).[8] In the remaining segment – households and other industry – temperature-adjusted demand fell by 7 per cent over the

[8] The response seems small in comparison to estimated reservation prices for the power-intensive industry. The industry has the option of moth-balling plant and selling power, obtained of preferential terms determined by the Norwegian Parliament, in the spot market (Bye and Larsson, 2003). The lack of response may be due to uncertainty about price developments, long stop and start-up times, and the risk of undermining popular and political support for the industry.

November-May period compared to the year before; given an average increase in end-user prices of 30 per cent, this corresponds to a price elasticity of 0.23.

The experience in Norway may be contrasted with that of the other Nordic countries. Although wholesale prices moved more or less in parallel, retail prices were much less affected in these countries. This would seem to be explained by the fact that retail markets differ, particularly in the availability and composition of contracts, but also in market structure and the extent of competition. In Denmark and Finland, where fixed-price contracts dominate, domestic consumers were much less exposed to price increases than in Norway. In Sweden, there is a greater variety of contract types, although the incidence of long-term, fixed-price contracts is higher than in Norway. Moreover, as we discuss below, there seems to be less competition among Swedish than among Norwegian retailers. Also, in Sweden retail prices reacted much less than in Norway. As a result, the demand response was much less in these countries than in Norway.

MARKET INTEGRATION AND RETAIL COMPETITION

The events of 2002-2003 cast light on a number of potential problems, including concentration and scope for market power, contractual coverage and exposure of consumers to price risks, investment and its impact on supply security, as well as bottlenecks in the transmission network and segmentation of the market. Below we focus on the retail market (this section) and issues concerning supply security and adequacy (next section). We also discuss how the introduction of new, market-based instruments for regulation of environmental emissions may impact on the performance of the electricity industry (penultimate section).

The establishment of Nord Pool and the elimination of border tariffs between the Nordic countries were key elements in a strategy aiming at an integrated Nordic market for electricity. The success of this strategy may be measured by the degree of wholesale and retail price equalisation between the different "price areas".[9] Obviously, an uneconomically large transmission capacity would be required if wholesale prices were to be equalised across all areas at all times. However, significant and persistent deviations between area prices would imply that the Nordic market consists, in effect, of a set of national or regional electricity markets.

As we show immediately below, the wholesale market appears to be strongly integrated, with prices in different areas diverging for shorter periods only. However, as mentioned above, retail market prices reacted very differently across the Nordic countries to the 2002-2003 increase in wholesale prices: while

[9] Whenever interconnector capacity constrains power flows, the Nord Pool market is divided into two or more "price areas". Sweden is always treated as a single price area, and the same applies to Finland. This is because congestion in the national transmission systems is managed by means of so-called counter-trade in these countries. In Denmark, the eastern and western parts of the country are physically separated and hence there are always two price areas – East and West. In Norway, segmentation of the market is part of the handling of transmission constraints and the country may be divided into two to five price areas, depending on the demand-supply configuration.

they shot up in Norway, the reaction was much more subdued in Sweden, and in Denmark and Finland retail prices hardly changed at all. There are also considerable differences in the level of retail prices, even when one corrects for differences in taxes and network tariffs. Some of these differences can be explained by differences in regulatory regimes. We concentrate our attention on Norway and Sweden, where regulations are similar, but where retail markets nevertheless seem to perform quite differently.

WHOLESALE PRICES

Table 1 displays the annual averages of the Elspot system[10] and area prices over the period 1996-2003. The figures indicate that deviations between system and area prices have been quite small. Except for the years 2000 and 2003 – when the supply of hydropower, especially in Norway, significantly deviated from normal levels – the Nordic electricity market appears to be reasonably close to being a "single market".

Table 1: Elspot system and area prices 1996-2003, annual averages, NOK/MWh (source: Nord Pool)

	1996	1997	1998	1999	2000	2001	2002	2003
System	253.6	135.0	116.4	112.1	103.4	186.5	201.0	297.5
Norway, Oslo	256.7	137.5	115.7	109.2	97.7	186.0	198.5	301.7
Norway, Tromsø	251.2	133.0	116.2	119.5	100.7	188.6	200.2	295.7
Sweden	250.6	135.0	114.3	113.1	115.5	184.2	206.3	292.8
Finland	-	-	116.3	113.7	120.7	184.0	203.8	277.9
Denmark, West	-	-	-	113.7	120.6	191.2	190.7	268.3
Denmark, East	-	-	-	-	-	189.7	213.7	291.7

However, small discrepancies between annual averages may hide short-term variations in different directions and is thus only a very crude indicator of the degree of price equalisation. As can be seen from Table 2, the number of hours in which the entire market has been integrated – that is, when the system price has been exactly equal to all area prices – is below 60 per cent. The corresponding figures for Finland-Sweden are in the range 75-100 per cent, for Norway (Oslo)-Sweden 70-85 per cent (except in 2000) and for Finland-Norway (Oslo)-Sweden 60-85 per cent (except in 2000). Moreover, the share of the time when Sweden has been a "price island" is in the range 0-5 per cent. Thus, in terms of wholesale price equalisation the Nordic electricity market would seem to be reasonably well integrated.

[10] The "system price" is calculated under the assumption that there are no transmission constraints. Actual trade is carried out at the system price only when transmission constraints are not binding.

Table 2: Number of hours with complete Elspot price equalisation 1997-2002 (source: www.seef.nu)[11]

	1997	1998	1999	2000	2001	2002
Number of hours	5 201	3 825	3 788	1 703	4 487	3 076
Share of time, %	59.4	43.7	43.2	19.4	51.2	35.1

RETAIL COMPETITION

There is complete market opening (i.e. full retail competition) in all the Nordic countries. In some of the countries, such as Sweden, a household consumer may even buy electricity from suppliers in any Nordic country. Given this, the pre-tax retail prices should not differ very much between the four Nordic countries. However, there are obstacles to transactions between suppliers in one country and households and other small customers in other countries. For instance, in order to be able to supply electricity to a Swedish customer located in Stockholm a non-Swedish supplier needs to buy electricity in the Stockholm price area. Moreover, as a buyer in the Stockholm price area the supplier needs to have a contract with a so-called “balance responsible party” (as well as in the home country).

As a result of such obstacles, only a sub-set of all retailers in the Nordic countries is actually competing on the Swedish market. In addition, only a sub-set of all Swedish retailers competes outside the geographical area in which they are located. Corresponding situations prevail in the other Nordic countries. Consequently, retail electricity prices need not necessarily be equalised across national borders. In order to shed some light on this issue, we have compared retail prices in Norway and Sweden, the two countries that have operated a common wholesale market since 1996.

Retail prices differ between households for several reasons. One reason is related to non-linearity of price schedules and annual consumption patterns of households. Thus prices paid by households living in a single-family houses with electric heating – typically consuming around 20 MWh per year – is lower than the prices paid by households using electricity only for lighting and electrical appliances, consuming as little as 2 MWh per year.[12] Another reason for retail price differences is that customers can choose between fixed-price contracts (with different duration) and variable-price contracts, and that the prices charged for these contracts may deviate in the course of year. In both Norway and Sweden, the “default contract” – the type of contract that applies for customers who have not actively chosen to change supplier or signed a new

[11] Presentation by Dr. Niklas Strand, Swedish Competition Authority, at the Swedish Association for Energy Economics.

[12] To some extent this pattern is surprising. On the one hand, it is likely that economies of scale may motivate some quantity discounts. On the other hand, it is obvious that households with electric heating consume electricity primarily during the winter period when peak generation capacity is used and spot prices are high. As spot prices are sometimes very high during the winter season, one would expect that the cost of offering the customer insurance against winter “price spikes”, which is what the retailer does, would be rather high.

contract with the "old" supplier – is a variable-price contract; that is, a contract that allows the supplier to adjust the price (after notifying the customer) and so, in effect, pass on cost increases to customers. A third reason for retail price differences is that individual retailers may adopt different market strategies and offer different combinations of prices and services.

In Table 3 and Table 4, annual averages household prices over the period 1997-2003 are displayed for, respectively, Norway and Sweden. The numbers reflect averages of prices offered by all retailers to households with an annual consumption equal to 20 MWh.

Table 3: Retail prices, net of taxes, for 20 MWh household consumer according to contract type in Norway 1997-2003, NOK/MWh (Source: Statistics Norway)

	1997	1998	1999	2000	2001	2002	2003
Normal	n.a.	160	151	141	210	205	454
Spot	n.a.	n.a.	131	123	193	193	323
1 year fixed	n.a.	n.a.	152	144	189	195	287
Average	210	162	152	141	206	203	414

Table 4: Retail prices, net of taxes, for 20 MWh household consumer according to contracts in Sweden 1996-2003, NOK/MWh (Source: Statistics Sweden)

	1997	1998	1999	2000	2001	2002	2003
Normal	259	251	244	218	225	296	447
1 year fixed				178	181	256	397
2 year fixed				177	184	253	351
3 year fixed				182	186	252	324

It is immediately clear that Norwegian and Swedish retail prices differ significantly. No "law of one price" is visible, and the retail prices have been significantly higher in Sweden during most of this period. Thus, with regard to the household market, there seems to be two national rather than one integrated Norwegian-Swedish electricity market.

Annual variations of the Norwegian retail prices are quite significant, but also relatively well correlated with variations in Elspot prices (comp. Table 1 and Table 3). Thus retail prices fell during the "wet" period 1997-2000, increased in 2001 when precipitation was "normal", and skyrocketed in 2003 when Nord Pool prices were extremely high. In the case of Sweden, however, the correlation between Elspot and retail prices was rather weak during the period 1996-1999. Instead, average retail prices remained high in 1998 and fell only marginally in 1999, while a quite significant reduction took place in 2000 and 2001.

The most obvious explanation for these differences between the development of retail prices in Norway and Sweden are related to switching costs at the household level. In Norway, a system of profiling was adopted from the outset and customers could switch to another supplier at no cost; more specifically, there were no requirement to install specific meters, nor any charges levied. The option of changing supplier at no charge has led to a sizeable swing of customers away from the “old” local suppliers to alien suppliers that offer electricity at lower prices. In other words, there were no significant switching costs protecting the “old” suppliers from competition.

In Sweden, on the other hand, costly real-time metering and reporting were required for consumers wanting to change supplier. These regulations were in effect until November 1999, and as a result few households changed supplier or renegotiated their contract with the “old” supplier. After November 1999, a system of profiling has been in place. Consequently, there was a significant reduction of switching costs in Sweden at the end of 1999. The figures in Table 4 suggest that retail competition was rather modest as long as switching costs were high. At the same time, the figures indicate that the reduction of switching costs opened up for a significant competitive pressure on retail prices.

Nevertheless, even with a regulatory regime more conducive to competition, retail prices continue to be higher in Sweden than in Norway, in spite of the fact that retailers procure electricity at the same well-integrated wholesale market. A natural hypothesis is that this is a result of market power.

MARKET STRUCTURE

Traditionally, the major generating companies in Sweden have had rather small shares of the retail market. Thus, although Vattenfall for a very long time has been the single biggest retailing company, its share of the retail market was only around 15 per cent in the middle of the 1990’s. However, in the last few years the major generating companies – Vattenfall, Sydkraft and Fortum (formerly Birka) – have bought majority or minority shares in a number of small and medium-sized retailing companies. In most cases, sellers have been towns and municipalities. Moreover, some of the independent retailing companies that entered the market in 1999, such as the Norwegian oil and gas company Statoil, have since left the market.

As a result of these developments the number of retailing companies has been reduced, and the “big three” have become dominant players on the retail market. For instance, if we include retailing companies in which generators own minority shares, Vattenfall is currently serving around 30 per cent of all Swedish customers, while the corresponding number for the “big three” is around 70 per cent. Similar numbers apply to shares of volumes of electricity delivered to final consumers.

In Norway, power generation has traditionally been much less concentrated than in Sweden. Except for the state-owned company Statkraft, accounting for some 30 per cent of total Norwegian power generation, generators are small, with market shares of 5 to 6 per cent or lower. As Statkraft and the second largest company, Norsk Hydro, almost exclusively serve industry and other businesses on long-term contracts, the retail and household market in Norway has been much less concentrated than in Sweden.

In recent years, however, significant changes in the Norwegian power sector have taken place. In particular, many companies in local-government ownership have been turned into limited-liability companies, often as part of a process leading up to the sale of ownership interests. Also, larger regional power companies have been established, partly by acquisition and partly through mergers. Furthermore, Statkraft has acquired stakes in several Norwegian power companies. Foreign companies have also acquired some ownership interests in Norwegian companies (notably in grid management and operations and in power retailing). In spite of these developments, however, the Norwegian market, both at the wholesale and retail level, remains less concentrated than its Swedish counterpart.

MARKET POWER AND PRICE DISCRIMINATION

So far, the retailing segment of the Swedish electricity supply industry has not been very profitable, and several entrants to the market have had to leave after having suffered significant losses. On the whole, it seems that the costs of the retailing business have been severely underestimated; in particular, it seems that the exposure to price- and quantity risks have been more costly than expected.[13] But in 2002 the established retailers were able to implement an increase in trade margins without attracting new entrants to the market. The question then is why “the big three” have grown while several independent retailers have left the market.

A possible explanation may be that integrated generation-retailing companies are more efficient than independent retailers. In Sweden, legal separation between retailing and distribution is required. This provision has paved the way for significant integration between generation and retailing. It seems that the integrated companies have a competitive advantage in relation to independent retailers stemming from the lack of efficient markets for hedging against area price and quantity risks. Thus, while all retailers may suffer from a combination of unexpectedly high area prices and consumption levels, the extra costs in the retailing business become extra revenues in the generation business for the integrated generation-retailing companies.

If these hypotheses could be verified they clearly point at an unexpected effect of the legal separation requirement in Sweden. The intention was to stimulate retail competition by preventing cross-subsidisation between distribution and retailing. This objective may have been attained, but recent developments suggest that allowing vertical integration between generation and retailing also made it possible to exercise market power in the retail market.

[13] Retailers can hedge Elspot system price risks at Eltermin, and the liquidity of these instruments (futures, forwards and options) traded at Eltermin is high. However, retailers in Sweden have to buy electricity at the relevant Swedish area price, and opportunities for hedging idiosyncratic area price risks are not very well developed. Moreover, retailers can only hedge price risks for a fixed number of MW:s per hour, while their customers do not have to commit to a certain quantity. Thus retailers are exposed to the risk of having to buy “extra” electricity at spot-market price during hours when their customers have an unexpectedly high level of consumption.

There also seems to be an element of price discrimination in Swedish retail prices. As seen in Table 4, there is a considerable spread between prices in the so-called "normal contract" and prices in fixed-prices contracts, or between prices paid by customers with default contracts and customers who have actively switched to a new contract; in particular, prices in default contracts are higher than those in fixed-price contracts. This suggests that Swedish retailers are able to price-discriminate against the default-contract customers. After all, by refraining from actively choosing another type of contract these customers have demonstrated that they are not very price-sensitive and it must be tempting for suppliers to utilise this information.

SUPPLY SECURITY AND ADEQUACY

A notable consequence of regulatory reform in the Nordic countries – and, indeed, one of its most important successes – has been the almost complete halt to investment in generation and, to a lesser extent, in transmission and distribution.

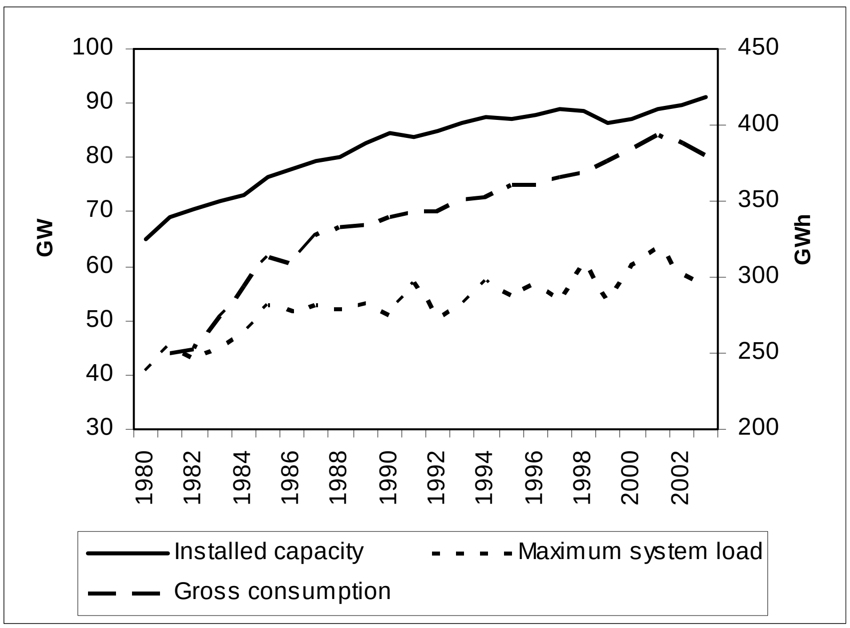

Figure 6: Capacity, consumption and system load (source: Nordel)

Figure 6 shows installed generation capacity in the Nordic market since 1980. Over the ten year period preceding the first regulatory initiative, from 1980 to 1990 (the year before the new Energy Act took effect in Norway), generation capacity grew by 30 per cent. Over the next ten year period, from 1990 to 2000, installed capacity grew by a mere 3 per cent. Indeed, in 2003 installed capacity was more or less the same as in 1996 – the year when regulatory reform was introduced in Sweden: a fall during 1998-9 was only reversed by subsequent increases in recent years.[14]

The stagnation in capacity growth cannot be explained by development of demand. Admittedly, demand did not grow at the pace experienced in the early 1980s and before, but gross consumption continued to grow at a more or less constant rate of 1-1.5 per cent per year (see Figure 6). As a consequence, over-capacity inherited from the pre-reform era has gradually being reduced, if not entirely eliminated. Comparing generation capacity and maximum system load, we find a similar picture, although the trend is perhaps not as pronounced. Nevertheless, the capacity margin – defined as the excess of installed generation capacity over maximum load – reached it lowest level in 2001.

The development of generation capacity must be seen in relation to stricter regulatory policies, arising mostly from environmental concerns. Although a considerable amount of undeveloped hydro capacity still remains, it is unlikely that many more new hydro sites will be developed. Nuclear power – traditionally important in both Finland and Sweden – has long been viewed with great scepticism (although the Finnish Parliament recently approved the building of a new nuclear power plant). Increasing concerns about air pollution has lead to strict regulations, not only on coal- and oil-fired power plants, but also gas-fired plants.

Notwithstanding the importance of environmental regulation, it would seem that regulatory reform – with the abolishment of monopoly rights, integration of markets and development of market places – has been the most important factor in determining generator investment behaviour. Market-based competition not only reduced prices, but also turned the focus of market participants towards profitability. Indeed, in an industry traditionally committed to a public service ethos, regulatory reform legitimised a more "capitalist attitude". The greater emphasis on profits lead to company restructuring and mergers, as well as to increased efficiency (eg., employment in the Norwegian electricity industry fell from almost 20,000 in 1993 to below 13,000 in 2002). Specifically, electricity supply companies increasingly required returns on investment in line with those obtained in other industries.

[14] This movement seems to be explained largely by plants that were first moth-balled and then re-opened.

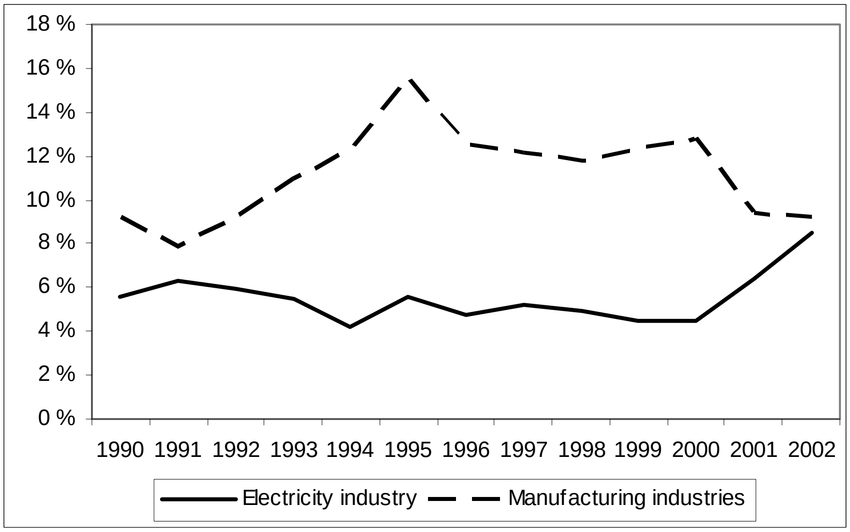

Figure 7: Return on capital, 1990-2002 (source: Statistics Norway)

Figure 7 shows return on capital in the Norwegian electricity industry since 1990, the year before deregulation.[15] Over this period, rate of return has averaged 5.5 per cent, only half that achieved in the Norwegian manufacturing industry. Due to the existence of a "resource rent" in a hydro-dominated electricity industry, we would expect the average rate of return to exceed that on a marginal plant. Consequently, it seems relatively safe to conclude that new investment in generation capacity could not have achieved reasonable levels of profitability over this period.

Nevertheless, even though low levels of investment seem to have been a rational response to prevailing market conditions, the question remains whether investment will be forthcoming as the earlier over-capacity is eroded and market conditions become tighter. In other words; are there reasons to believe that market imperfections will inhibit investment and undermine the future performance of the industry?

In order to answer this question, it is important to distinguish between two related, but nevertheless entirely different, concepts: supply security or balancing consumption and generation on a continuous basis within existing capacity limits; and supply adequacy or ensuring optimal capacity investment by balancing willingness to pay for new capacity against its cost.

In other words, while the supply-security issue is short term and mainly concerns system operation, the supply-adequacy issue is long term and concerns the evolution of capacity in relation to consumption. In interpreting the balance of consumption and generation one must be aware of transmission constraints

[15] Rate of return is measured according to National Accounts as operating surplus relative to the value of capital employed.

that limit the range of generators that can meet demand in a given location. Below, we discuss these issues in some detail.

SUPPLY SECURITY: BALANCING DEMAND AND SUPPLY

As is well known, the problem of continuously balancing consumption and available generation arises from specific features of electricity markets, including the need for electrical equilibrium at all times, unexpected variations in demand and supply, limited possibilities for establishing and transmitting adequate price signals to market participants on a continuous basis, and limited short-run response by market participants to price signals.

The gain from increasing supply security is associated with a reduction in the costs of rationing. A rationing event occurs when, at prevailing prices, the desired demand and/or supply of market participants cannot be satisfied and hence their decisions have to be constrained. For example, if demand exceeds supply at prevailing prices, either additional supply (if available) has to be ordered onto the system, or the consumption of one or more consumers has to be forced down. Rationing may be voluntary or involuntary. One example of a voluntary rationing agreement is contracts for operational reserves, by which the system operator obtains the right to call on additional supplies when needed. Another example is long-term load-shedding contracts between consumers and their suppliers (or between consumers and the system operator), by which consumers, upon conditions that have been agreed in the contracts, can be called on to reduce their load. Involuntary rationing typically occurs by zonal interruptions of power supplies.

Supply security cannot be ensured by capacity investment alone, although a larger capacity may reduce supply security problems. Optimal utilisation of existing generation capacity – whatever its level – involves setting prices that allow for the highest possible degree of capacity utilisation while at the same time securing sufficient reserve margins. Having more capacity available essentially means that prices will remain at lower levels so that more demand is encouraged and a high level of capacity utilisation is ensured. Conversely, when capacity is limited prices will increase so as to reduce demand. Provided generation capacity is optimally used, on longer time scales demand for capacity will follow available capacity and system reserves will not be directly linked to total capacity.

Obviously, in the Nordic system, with a large incidence of hydro power, there will be sustained periods of time in which the energy balance is tight. In such situations, a continued balance between demand and supply requires that prices rise, as happened during the winter of 2002-2003. Note that the price rise would have been less in that event if more of demand had been exposed to the actual cost of electricity: the reliance on fixed-price contracts in large segments of the market exacerbated the supply deficit and pushed wholesale prices higher than they otherwise would have been. On the other hand, it is conceivable that one may in the future experience an even more severe reduction in inflows, with even higher prices as a result. Nevertheless, if, by adjusting price levels, demand can be scaled to be (on average) aligned with existing capacity, the supply security problem is not associated with the level of demand (relative to existing capacity) *per se* but rather with variations in demand (and capacity availability).

Given this, it must be noted that, in a hydro system, even if the energy balance is tight there is generally a large amount of (power) capacity available. Since hydro plants are typically constructed so as to be able to handle peak inflow levels, and adjustment of output is extremely cheap, the ability to deal with short-term variations in the system is not necessarily impaired in dry periods.

To sum up, it is not at all clear that the Nordic market is particularly vulnerable to supply insecurity, even if market conditions were to become tighter in the future. Indeed, the technology mix – and the mere size of the market – would seem to allow for a very high degree of supply security.

Moreover, regulations are in place which should provide Nordic system operators with the tools they need to balance the system. Take the Norwegian TSO Statnett as an example. Firstly, rights and responsibilities have been clearly set out in specific regulations; in particular, Statnett is responsible for system balance and have the right to make the necessary contractual arrangements with market participants to achieve this task. Secondly, market-based institutions have been set up to achieve balancing in a cost-effective manner. Most importantly, Statnett runs a (near-to) real-time balancing markets in which balancing services are sourced on a short-term basis. Furthermore, at regular intervals Statnett procure strategic reserves, partly in the form of contracts for interruptible demand. All in all, these instruments should be sufficient to guarantee that balancing is achieved at reasonable costs.

Studies have indicated that the efficiency of system operations would be further enhanced by tighter co-operation between of system operators (Bjørndal and Jørnsten, 2001; see also von der Fehr, Hagen and Hope, 2002). Developments in this direction have recently taken place, with integration of the national balancing markets (Nordel, 2003). However, these efforts are probably not sufficient, and further gains may be had from optimising the system as a whole, including lower overall reserve margins and increased transmission capacity.

SUPPLY ADEQUACY: OPTIMISING CAPACITY INVESTMENT

The supply adequacy problem essentially consists of two elements, namely ensuring an optimal level of overall generation capacity and an optimal mix of different generation technologies.

An optimal level of overall capacity is characterised by equality between willingness to pay for new capacity and the cost of such capacity. In other words, a situation of under-investment in generation capacity would be characterised by investment not forthcoming even though the willingness to pay for the associated increase in output is more than sufficient to cover its cost. Similarly, a situation of over-investment would be characterised by the cost of marginal capacity units exceeding consumer willingness to pay for the associated output – a situation well known from the history of the Nordic electricity industry.

An optimal mix of generation technologies is characterised by the minimisation of costs of satisfying a given consumption profile. Cost-efficient operation requires a mix of technologies with different variable to fixed cost ratios. At one extreme, low-variable/high-fixed costs technologies – such as hydro, nuclear and conventional thermal – operate continuously as base-load units; at the other extreme, high-variable/low-fixed costs technologies – such as small gas- or oil-fired units – are used for demand peaks only. An optimal capacity mix balances the gains from reducing variable operating costs by having more base-load units available against the higher fixed costs of such units.

At the moment, there would seem to be two major concerns regarding supply adequacy in the Nordic market: firstly, whether investment incentives are sufficient to allow overall capacity to expand at a reasonable pace, and secondly, how the generation park will be affected by the introduction of new environmental regulation initiatives. Here we focus on the first issue of general investment incentives and leave the latter issue for the next section.

In the hydro-dominated Nordic market, wholesale prices swing from year to year, depending upon hydrological conditions. However, these fluctuations in prices tend to average out. Indeed, judging from prices in forward contracts – which are traded up to three years ahead on Nord Pool – expected prices tend to be quite stable, evolving slowly in reaction to changes in underlying fundamentals. At the time of writing, contracts for two and three years ahead are trading at around 250 NOK/MWh, a level that would make investment in conventional gas-fired plant approximately break even.

It would seem that these prices are in fact sufficient to attract investor interest. The Finnish government and the EU Commission recently approved a new 1.6 GW nuclear power plant, expected to be in operation from 2009. In Norway, Statoil recently unveiled plans to build a 860 MW gas-fired plant and a 280 MW co-generation unit at its industrial plants at Tjeldbergodden and Mongstad (landing points for North-Sea gas). Gas-fired generation has been a source of controversy in Norway – leading to the downfall of at least one government – and it remains to be seen whether the Statoil projects will be approved. However, whatever the outcome, it would seem that generation investment in the Nordic market is not so much a question of commercial, as of political, will.[16]

Transmission investment has been fairly limited for a number of years. There seems to be two main issues: first, how regulation of the individual TSO affects investment incentives and, second, the ability of national TSOs to solve co-ordination problems associated with investment in interconnector capacity. In the case of the Norwegian TSO, Statnett, there appears to be no lack of will to invest. Given that costs of new investment will in effect be passed on to network users, Statnett has shown considerable willingness to undertake new projects. Were it not for the more restrictive view taken by Norwegian regulatory authorities, more transmission capacity would indeed have been

[16] Uncertainty surrounding the future of the Swedish nuclear capacity is another important example of how the political process interacts with investment incentives. Investment in renewables, such as wind power and generation based on burning of biomass, is critically dependent upon government support.

built.[17] The regulatory regimes differ somewhat between the Nordic countries, which may explain why other TSOs have been more reluctant to invest, particularly in new interconnector capacity. However, Nordel – the association of Nordic TSOs – has taken several initiatives both to resolve problems associated with transit (Nordel, 2001), as well as producing plans for co-ordinated expansion of the Nordic transmission network (cf. the "Nordic Grid Master Plan" described in Nordel, 2003). These initiatives would seem to a go a long way in resolving transmission problems, but, again, it would seem that regulatory and political will, rather than commercial will, is going to be decisive.

EMISSIONS TRADING

The EU Directive of emissions trading was adopted in July 2003 and will be implemented in 2005 (European Commission, 2003). In the beginning, the system will only comprise emissions of carbon dioxide (CO_2), but other Greenhouse gases will be included later. The EU Emissions Trading Scheme (ETS) covers a wide range of industrial sectors, representing some 45% of EU CO_2-emissions. One of the sectors included in the scheme is electricity and district-heating. It is expected that the introduction of the ETS will significantly influence this sector.

According to the Directive, Member States are responsible for allocating emission permits to companies under their jurisdiction. At first, permits will be granted free of charge in accordance with National Allocation Plans approved by the Commission. The number of permits will be reduced over time. The ETS implies that a participating company, on the margin, will be faced with the decision of whether to use a permit to cover its own emissions or to reduce emissions in order to be able to sell the permit on the market. A company not able to fulfil its emission target with the assigned permits may either purchase permits or pay a penalty for non-covered emission. In principle, the possibility of buying, selling and trading permits will result in a single price of permits and lead to equalisation of marginal abatement costs of CO_2 across companies, sectors and countries, thereby minimising the total costs of reaching the EU-target of emission reductions.

Among the Nordic countries, Denmark, Finland and Sweden will – as EU Member States – have to implement the ETS, while Norway, not being a member state, is not obliged to do so. However, Norway has recently redesigned its former national (more ambitious) emissions trading scheme proposal to better fit the EU Directive, and Norway seeks in this way to cooperate and participate in the EU arrangement on an equal footing with the other Nordic countries. A possible outcome of this process is that Norway adopts the EU Directive and thus commits to the rules and regulations of the ETS. This option still awaits parliamentary approval.

[17] Statnett recently failed to get approval for a subsea link to the UK. It would seem that the business case for this project was indeed weak (Aune, 2003). Statnett is however going to undertake considerable investments in the Norwegian network over the coming years (see www.Statnett.no).

Due to the different structures of generation technologies, and the resulting variation of CO_2-emissions, emissions trading may give rise to significant changes in the Nordic power market. The structure of generation technologies is given in Table 5. Norway represents an extreme case, with electricity generation almost exclusively based on hydro-power. Danish electricity and heat generation is primarily based on coal and natural gas, Swedish electricity generation is based on a combination of hydro power and nuclear power, while Finland has a broad range of generation technologies, including bio-fuels.

Table 5: Total electricity generation by energy source in 2003, TWh (Source: Nordel)

	Denmark	Finland	Norway	Sweden	Total
Hydropower	0.0	9.3	106.0	53.0	168.3
Nuclear power		21.8		65.5	87.3
Coal	23.9	18.2		2.5	44.6
Natural gas	9.9	11.0	0.3	1.3	22.5
Oil	1.5	1.9		4.0	7.4
Wind power	5.6	0.1	0.2	0.6	6.5
Biofuel	2.4	10.1		5.0	17.5
Peat and other	0.3	7.5	0.7	0.7	9.2
Total generation	43.6	79.9	107.0	132.6	364.1
Total consumption	35.0	84.8	115.1	145.5	380.4

Table 6 gives numbers for CO_2-emission in electricity and heat supply. The levels of CO_2-emissions are very different. Denmark, with its relatively small electricity industry, has the highest level of emissions, whereas Norway, with a relatively large electricity industry, has almost negligible emissions.

Table 6: CO2-emissions in public electricity and heat supply in 1998, Mton (Source: IEA)

Denmark	Finland	Norway	Sweden
27.8	18.2	0.2	7.9

The simple idea of the ETS is that the permit price will function as a cost increment of using a CO_2-emitting resource, with the increment being in proportion to how much that resource emits per unit used. As a result, input substitution is expected to take place in electricity generation, away from coal and gas power towards hydro, wind and nuclear power. Hence it is to be expected that, in the Nordic countries, the ETS will result in an increase in the relative importance of electricity based on “clean” power, accompanied by increasing electricity prices and a relative increase in the export of electricity from countries endowed with clean natural power resources, such as Norway. This is, indeed, what earlier studies of the effects of a common Nordic market for emission permits show; see Amundsen et al. (1999), Unger and Alm (2000) and Hauch (2003).

It should be noted that these studies show that the introduction of a common Nordic electricity market has in itself lead to considerable reductions in CO_2- emissions. The reason for this is that increased levels of electricity trade lead to substitution of low-cost and emission-free hydro power for electricity generated by high-cost emission-intensive sources.[18] Nevertheless, introducing a common Nordic market for emission trade will provide an additional gain. The reason is that equalisation of both marginal generation costs (resulting from trade in electricity) and marginal abatement costs (resulting from trade in permits) is more efficient than equalisation of either of these alone.

THE NORDIC MARKET FOR GREEN CERTIFICATES

In recent years, a Nordic market for Tradable Green Certificates (TGCs) has been under development in order to facilitate the use of so-called green electricity, i.e. electricity generated by wind-power plants, new small hydro-power plants and power plants using bio fuels. Sweden introduced its TGC-system on May 1, 2003 and Norway will follow suit in 2006. It is the intention that Norway and Sweden will start trading TGCs from that year on. The Nordic TGC-system was to a large extent designed in Denmark and plans existed for its introduction already in 2001. Although the legal foundation for implementation was in place in Denmark, the TGC-system has been put on hold, and no decision has been made as to when it will be implemented. Finland has no immediate plans of introducing a TGC-system but does participate in the European RECS system, as do the other Nordic countries.[19]

Sellers of TGCs are producers of electricity using renewable sources. They are issued with a number of certificates corresponding to the amount of electricity they feed into the electricity network. Buyers of TGCs are consumers/distribution companies that are required by the government to hold a certain percentage of certificates corresponding to their total consumption/end-use deliveries of electricity. The percentage requirement functions as a check on total electricity consumption, as the total number of certificates available is determined by the total capacity of renewable technologies. The TGCs are thus seen as permits for consuming electricity. The system implies that producers using renewable energy sources receive both the wholesale price and a certificate for each kWh fed into the electricity network. In a competitive equilibrium, therefore, marginal generation cost of green electricity is equal to the marginal generation cost of non-green electricity plus the subsidy element (i.e. the TGC price). Hence, for the producer, the marginal cost of providing a kWh of green electricity is the same as that of non-green electricity, wherefore both technologies will be involved in power generation at the margin. In this

[18] This result is, however, sensitive to the relative cost of electricity generation for the various technologies employed and to future market development. For instance, enlarging the power market to include Northern Germany may well result in larger imports of low-cost, carbon-intensive coal power and lead to more CO_2-emission. In such a setting, the value of introducing ETS will be significant. The introduction of ETS may lead to an increase of end-user prices and reduced demand for electricity. Hence, even though ETS will stimulate electricity exports from countries rich in clean power resources, reduced demand for electricity may still dampen electricity transmission between countries.

[19] The European RECS (“Renewable Energy Certificate System”) facilitates many support schemes for green energy, rather than being a support scheme itself. It is not restricted by national boundaries. RECS provides a mechanism for presenting production of a megawatt-hour of renewable energy by a unique certificate which can be transferred from owner to owner before being used as proof of generation, or exchanged for financial support (http://www.treckin.com).

way, the TGC-system is supposed to stimulate new investments in green electricity generation.

Analytically, the TGC-system implies that the end-user price of electricity becomes equal to the wholesale price plus a percentage of the certificate price (assuming zero distribution costs), determined by the holding requirement. In a competitive electricity market, end-user price is also equal to a linear combination of the marginal generation cost of green electricity and the marginal cost of non-green electricity, with the percentage requirement as the combination weight. Hence a change of the percentage requirement will affect the relevant marginal generation cost. However, as the system is founded on a percentage basis, it is not necessarily true that an increase of the percentage requirement leads to more green generation capacity, though it will lead to less non-green generation capacity (Amundsen and Mortensen, 2001, 2002). [20]

JOINT EFFECTS AND COMPATIBILITY OF ETS AND TGC

Both the ETS-system and the TGC-system will affect CO_2-emissions from electricity and heat generation. In this sense, these are two broad market-based measures (on top of other measures like emission standards, direct subsidies for renewables etc.) to obtain the goal of reducing CO_2-emissions (other considerations, such as supply security and infant industry protection also motivated the introduction of the TGC system). In order to provide an indication of the possible effects of these measures, we refer to some results from a simulation study of the Nordic electricity market focusing on Sweden, which, as mentioned, has already introduced a TGC-market (Bergman and Radetzki, 2003).

The introduction of the TGC-system in Sweden (based on a 7% requirement) will lead to certificate prices at the stipulated upper price bound and an increase in the production of green electricity by 10 TWh. However, net export to the other Nordic countries will increase by 5.2 TWh. This somewhat surprising result is explained by the high price of certificates and the resulting low net cost of generating green electricity in Sweden. Hence the introduction of a TGC-system in Sweden significantly affects investment decisions in the electricity industry. However, since in these simulations Sweden is assumed to be the only country applying a TGC system, the effect on the common Nordic electricity wholesale price is rather small.

With a joint Nordic ETS-system in place (or, equivalently, a joint CO_2-tax), Bergman and Radetzki calculate that electricity consumption in Sweden would be reduced by an amount corresponding to the growth in demand over the period 2001-2010 which would otherwise have occurred (i.e. without such a scheme). Hence, CO_2-emissions from the electricity sector are reduced at the expense of electricity consumption. However, as the cost increase is even higher in Denmark and Finland, the competitive position of the Swedish electricity

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[20] Potentially, the TGC-system involves some serious problems. For instance, certificate prices may be extremely volatile if wind power constitutes a large part of the renewable technologies. Also, problems of market power (i.e. gaming on the electricity and GC-markets) may be severe and lead to a collapse of the system (Amundsen and Nese, 2004).

industry improves and Sweden begins to export electricity to Denmark and Finland.[21]

As for Norway, the introduction of the TGC-system in 2006 is targeted at stimulating power generation from wind and bio-fuel sources. Norway is already well endowed with environmentally friendly hydro-power resources, but the construction of new large hydro-power plants has more or less come to a halt, due to the lack of sites for large-scale developments. This is in part due to politically imposed environmental constraints and conflicting interests of land use. The emerging alternative is large-scale gas-power plants. The introduction of the ETS-system will reduce the profitability of planned gas-power plants (unless they are not exempted from the ETS-system). However, with the present ambition of the ETS-system it is not quite obvious that the resulting increase in the wholesale price will be sufficient to stimulate the required investment in electricity plants based on wind-power and bio fuel. Thus, in order to realise these plans a sizable stimulus, such as a TGC-market (or plain subsidies for that matter), is called for.

Although the two measures work towards the same end – that is, of reducing CO_2-emissions – they are not quite compatible. For instance, under the ETS-system, stricter emission constraints will lead to increasing permit prices, increasing generation costs for non-green power and thus increasing wholesale prices of electricity. Remuneration to generators of green electricity – that is, the wholesale price of electricity plus the value of a TGC – will however decrease.

The reason for this somewhat paradoxical result is the particular construction of the TGC-system, whereby an increase of the wholesale price by one cent results in a reduction of the TGC-price by several cents (depending on the size of the percentage requirement). The increase in the wholesale price, following a higher permit price, leads to a corresponding reduction of the margin between the end-user price and the wholesale price. This margin is equal to the TGC-price multiplied by the percentage requirement. Hence if this margin is reduced by one cent, and the percentage requirement is 20 per cent, the TGC price will be reduced 1/0.2 = 5 cents. The remuneration to a green producer (the sum of the wholesale price and the TGC-price) is therefore reduced. The equilibrium effect of stricter emissions constraints is a reduction of both non-green and green electricity generation, such that the percentage requirement is still satisfied (for further explanation, see Amundsen and Mortensen, 2001).

Investigating this problem in a numerical model, comprising both an ETS-system and TGC-system for the Nordic countries, Unger and Ahlgren (2003) identifies a negative effect of stricter CO_2-constraints on green electricity generation capacity. They conclude that this effect is probably not very large in the longer run, as the effect of constraining CO_2-emissions further will have only a small effect on electricity wholesale price.

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[21] Broadly speaking, these conclusions seem to be in line with other model simulation studies of the joint effects of ETS and TGC systems in the Nordic countries; see Hindsberger et al. (2003) and Unger and Ahlgren (2003).

CONCLUSION

During the winter of 2002-2003, the electricity market was front-page news almost daily. The obvious reason – and perhaps the main concern – was the impact of high prices on customer bills. After a sustained period of low prices, consumers were not prepared for a sudden price increase. Nevertheless, all in all it must be said that the market withstood the test and handled the supply shock rather well: prices adjusted rapidly and both demand and supply responded. Drastic measures such as rationing – foreseen by some and feared by many – were never warranted. As such, it would seem that the market has reached maturity.

Nevertheless, this event also made it clear that potential problems still exist. As the over-capacity of the pre-reform era is vanishing, the market is becoming increasingly tight. One must consequently be prepared, not only for higher, but also more variable prices. Tighter market conditions also means that system operation will become more challenging, particularly ensuring the availability of sufficient reserves of generation capacity and, most importantly, interruptible demand so as to achieve system balance at all times. Nordic system operators seem on the whole to be well prepared, although further co-operation (integration) of system operations could potentially enhance efficiency.

Tighter market conditions and increasing prices signal a need for capacity additions. So far, there is little evidence that generators do not react to such signals: indeed, at the time of writing capacity additions are either being planned or are already under way. However, uncertainty surrounding the political will to accept growth in electricity generation and consumption – exemplified with the lack of clarity about new measures for regulating environmental pollution – may undermine the willingness to invest. From a supply adequacy point of view, it is important that such political and regulatory uncertainty be kept to a minimum.

Further investment in transmission capacity is also likely to be warranted, especially in light of increasing concentration of the Nordic electricity industry. A low level of concentration may have been the most important factor underlying the success of the regulatory reform so far, and it would be a pity if mergers – horizontally and vertically – were allowed to undermine the performance of the industry. There is reason to believe that the difference in end-user prices between Norway and Sweden may be explained by a lack of competition in the Swedish retail market resulting from a combination of vertical integration between generation and retail and high levels of concentration. Similarly, tighter market conditions and more frequent occurrence of bottlenecks in the transmission system are signs of increasing segmentation of the market that may lead to higher prices also at the wholesale level. Only a combination of adequate investment incentives and strict competition policy can ensure the continued success of the Nordic electricity market.

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