

A Nordic energy market under stress

Torstein Bye

The Nordic electricity market was exposed to an extreme primary energy shock during 2002 and 2003. A short-term shortage of precipitation and inflow entailed sharply increasing prices and vigorous discussions about the functioning of the deregulated market when exposed to such extreme situations. As a consequence, several policy instruments that could relieve so-called infirmities in the market were launched. In this article, we show that the market functioned remarkably well; the producers tried to optimise the value of water as expected, electricity trade followed anticipated patterns, and consumers responded according to theory. We also show that the historic rate of return in power production explains low investments in production capacity. Moreover, expectations of futures prices do not justify expansion in the production capacity as yet, despite the high price level in 2002-2003. Although the market seems to have functioned well, the article points at some elements for further study and follow-up by the competition authorities.

1. Introduction

The Nordic electricity prices were much higher than usual in the late fall of 2002 and winter of 2003. Electricity producers claim that a dry summer and a cold and dry fall and winter were the main reasons for the high prices. Precipitation was low and put a stress on water reservoirs. But in the media it was frequently argued that the electricity producers exported too much electricity in the late summer and early fall, reducing water reservoir levels to a record low and driving prices upwards. The claim was that producers should have kept a higher security level of the water storage to make sure there was enough water for the winter demand. Some even proposed that a lower bound on reservoir levels should be implemented as a regulatory mechanism.

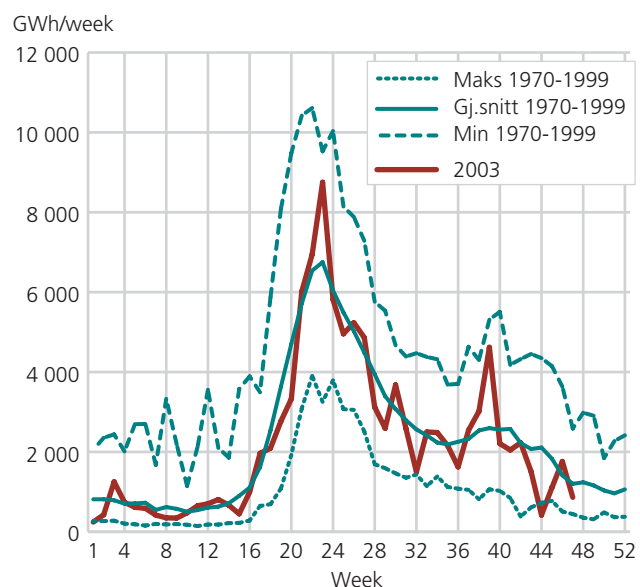
In this article, we take a closer look at the validity of these claims. We particularly ask if the development could be explained by normal optimising behaviour in a free competitive market. This includes a discussion of the link between the physical spot market and the financial risk hedging market at the NordPool exchange. We also investigate the demand side responses, as many seem to believe that consumers do not respond to increasing prices. Thus increasing prices just imply income redistribution, and do not help out in securing the market when primary energy inflow fails. We also ask whether market failure has led to inefficient investment decisions or if normal incentive indicators may explain the lack of investments.

2. What happened to inflow?

The common view concerning the Norwegian water balance in 2002 seems to be that it was a very dry year, something which created problems in the hydro-based electricity market. The total inflow to Norwegian reservoirs in 2002 was some 111 TWh compared to a normal level of 118 TWh. The 90 per cent confidence interval, with respect to the stochastic inflow to this system, is 90-145 TWh a year. A 6 per cent lower than normal inflow could then hardly be characterised as a particularly dry year. So what was the problem?

From figure 1 we find that during the first 22 weeks of 2002 the water supply was some 30 per cent (14 TWh) above *normal* (average of the period 1979-

Figure 1. Effective inflow to the Norwegian reservoirs during 2002 and 2003 compared to normal. GWh/week



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Figure 2. The development of the reservoir level. Deviations from the average development. Per cent

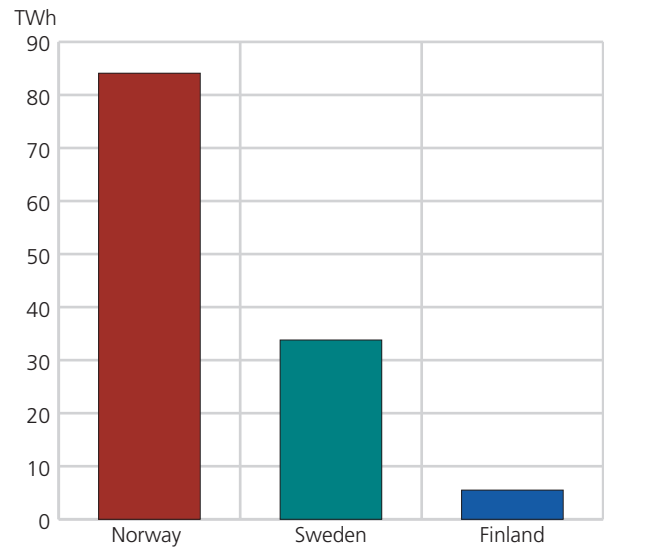


1990). Then, in week 23, the precipitation and inflow decreased sharply, and eventually became lower than normal. During the last 20 weeks of 2002 the accumulated inflow was 30 per cent (21 TWh) below average for these weeks over the period 1979-1999. At the same time, the abnormal precipitation led to groundwater losses, i.e. further precipitation had to re-establish the water balance in the ground before the reservoir level increased. The probability for this low or lower inflow, referring to the statistics of 70 years of inflow variation, is calculated at 0.5 per cent, i.e. this would occur in one out of two hundred years. Producers calculate expected water inflow as a total of possible outcomes weighted by their probabilities. Since the probability of low inflow is low, the expected value is hardly influenced. Producer behaviour during the fall of 2002 may then well be in line with an optimal risk management, despite the fact that the actual production path eventually led to a shortage of water and high prices in the market.

The Nordic electricity market is integrated via transmission lines with continuous exchange of power across country borders. Although some countries (Denmark and Finland) base their supply on thermal technology, others (Sweden and Finland) include hydropower and water reservoirs as in Norway, although the relative share of hydropower is smaller in these countries. The inflows to the Norwegian, Swedish and Finnish reservoirs are highly correlated. In figure 2 we depict the development of the reservoir filling level in these countries in 2002 and 2003.

We see that the total reservoir level in spring was well above the average over time. The reservoir level in Sweden was some 30 per cent above the normal level in week 20, while in Finland it was 17 per cent above and only 10 per cent above in Norway. The total

Figure 3. The water storage capacity in the Norwegian, Swedish and Finnish reservoirs. TWh



Nordic reservoir level was approximately 15 per cent above normal. The reservoir filling started to drop fast, compared to normal, during the early fall, as precipitation failed and demand increased. At the end of the year, the filling was approximately 25 per cent below normal.

Although the drop in the reservoir level was highest in Sweden (from 25 per cent above to 25 per cent below) and lowest in Norway (from 10 per cent above to 24 per cent below) the volume drop was highest in Norway, from plus 8 TWh to a negative difference of 21 TWh, compared to plus/minus 8 TWh in Sweden. Figure 3 shows the reservoir capacities in the three countries, underlining the importance of Norway as the largest hydropower contributor among these countries.

3. The producer problem

The fundamental profit maximising problem for a hydropower producer is to optimise the value of a stochastic inflow of water over time, see Førsund (1994). The reservoir is an instrument to equalise prices over time, which under simplifying assumptions secures the maximisation of profit from the production of power. As long as a sufficient number of producers compete efficiently, no transmission constraints occur, a sufficient storing capacity exists, and precipitation, inflow and weather are normal, equalising prices over periods also secure the optimisation of social surplus. Under no constraints this optimising strategy secures equal prices for electricity in space and time.

In reality these assumptions are too simplistic. The supply side of the market has become increasingly concentrated, the production capacities are limited, short term marginal costs differ between countries, constraints in transmission eventually occur, and

uncertainty about inflow is important. Let us take a closer look at some of these aspects.

3.1. Market imperfections

Over the last 5 years, the supply side has become increasingly *concentrated* as a consequence of acquisitions and formal and informal cooperation. This may open up for the exercise of market power. According to Bye, Fehr, Riis and Sørgaard (2003), it is unlikely that market power has been exercised so far in the Norwegian electricity market, but it could be in the future.

3.2. Limited storing capacity

In the short term, the storing capacity, which allows for the transfer of water from one period to another, is limited. A large inflow in one period may imply water overflow in another, since the expected value of inflow in the second period may override the generating and storing capacity. The capacity of the generators and reservoirs will be too small to take care of the large inflow. It could also be the other way around, i.e. the level of water is too low to satisfy demand before the rainfall season. A large amount of non-storable precipitation, i.e. river plants, may also imply a downward pressure on prices despite the storing capacity in other parts of the market. As a result the link between prices over time is distorted. The uncertainty about future water inflow is large and demand will fluctuate due to temperature changes. Again, these are important elements in the producer's daily production and storing strategy.

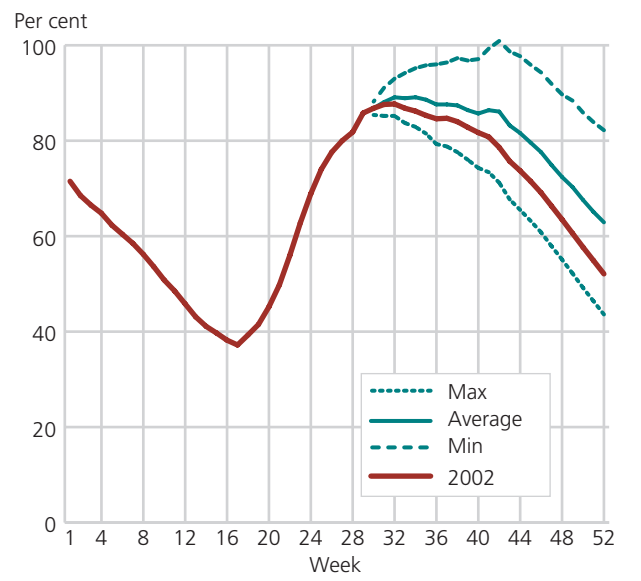
3.3. Limited generation capacity

Several other constraints may occur on the supply side. The generation capacity is limited and may in periods be insufficient to satisfy demand, i.e. prices increase to secure market balance. Most hydropower plants run under a set of regulations including a minimum and/or maximum allowable water flow, and a maximum and/or a minimum change in the water flow etc. When the limitations are effective, price is the only instrument to secure market balance. Constraints will then imply price differences in space and time.

3.4. External trade and increasing cost of short term supply

The short-term marginal production cost in a hydropower plant is very low, but on the demand side the value of water may be high. The Norwegian hydropower dominated market is linked with the markets abroad with thermal dominating technologies through transmission lines. In the expansion process of the thermal-based power market an important aspect is to combine base load technologies with high capital costs and low operating costs, and peak load capacities with low capital costs and high variable costs. This implies a stepwise upward sloping supply curve. When demand is high, prices increase and the market

Figure 4. Actual, minimum and maximum possible storage level. Week 30, 2002.



equilibrium moves upwards the supply curve abroad. As a result the value of water and prices of electricity in Norway also increase. Demand decreases and the excess supply in the Norwegian market is exported (exchange in accordance with profitability conditions). When demand in Europe is low, market prices are low; some of the marginal technologies are out of short-term business. When prices are low, the hydropower production is reduced, water is stored, and normally there is a net import to the Norwegian market.

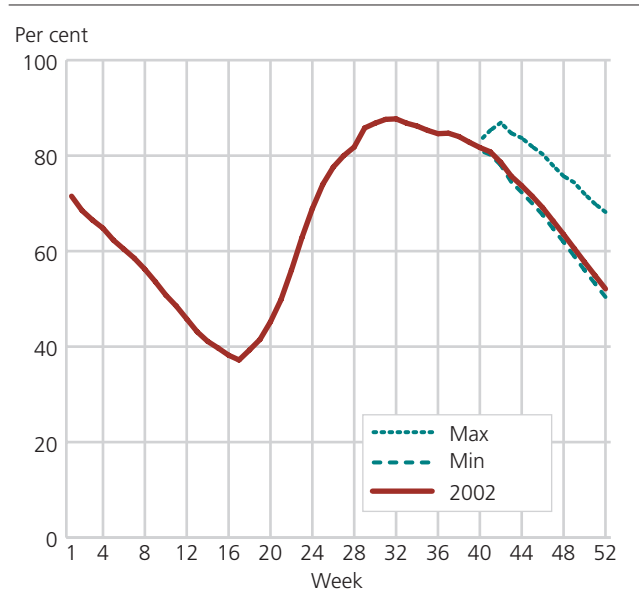
3.5. Transmission constraints

Since the power production technology, and thereby short term marginal cost, differs between countries, and since hydropower plants and consumers are located in different regions, transmission constraints often arise. For instance, during the winter of 2002-2003 (1 October to 1 March) transmission constraints between Denmark and Norway and between Denmark and Sweden, see Nordel (2003), occurred in 3300 out of 4400 hours. Transmission constraints imply price differences over time and across regions, and thereby influence producer behaviour. Even domestic transmission constraints occur frequently, especially under such circumstances as the fall of 2002 and winter of 2003. Uncertainty about future transmission constraints complicates the optimisation of the value of water both regionally and over time.

3.6. Uncertainty about inflow

As mentioned earlier, the 90 per cent confidence interval for annual inflow to the Norwegian hydropower reservoirs is 90-145 TWh. During the first half of 2002, inflow was above the normal level. Since temperatures and the business cycle changed only to a minor extent, demand was normal. Consequently, the stored amount of water was also high. An unusually

Figure 5. Actual, minimum and maximum possible storage level. Week 40, 2002.



warm and long summer implied decreased demand. Thus, producers estimated the futures' value as relatively low compared to normal at this point of the year, i.e. the willingness to produce was relatively high. This is underlined by the fact that there was a positive possibility for overflow when precipitation was expected to increase in the autumn. Figure 4 depicts actual, minimum and maximum possible storage levels during the fall when demand and production were assumed to be normal, referring to the actual reservoir level in week 30 (1 August).

Figure 5 shows the minimum and maximum possible storage level for the rest of the year, assuming normal production and demand from week 40 to the end of the year (1 October). We observe that at this point in time there is a zero possibility that overflow will occur, but still the actual production during this period is high. Two factors are important to bear in mind: First, prices in the day-ahead market had started to increase, sending signals to the reservoir owners to produce more electricity. Second, despite the fact that there was no possibility of overflow, the upper bound storage level was approximately normal. Since prices were above normal, again, the important incentive for the producer was to produce when prices were relatively high compared to earlier equivalent physical periods.

3.7. A complex optimisation

Uncertainty about inflow of water to the hydropower system is large, and demand changes due to temperature variation. In combination with all the restrictions that may occur in the storing, generating and transmission capacities, and the changing marginal cost of production from thermal plants, this supply and demand uncertainty creates a complex optimisation procedure for the hydropower producers. Eventually, this

causes prices to be high or low and differ between regions, depending on the inflows, but also depending on which capacity constraint is limiting. The underlying strategy from a hydropower producer, however, is still to equalise prices over time.

How can the producer deal with these uncertainties? A large number of market participants place bids and offers on the NordPool Exchange, which calculates the balancing price in the market on a 24-hour basis. Indirectly the NordPool market is an exchange of information on the cost of production and willingness to pay in the daily market. The aggregated information helps the market clearance. The electricity market is divided into regional markets, with systematic price differences between regions when transmission constraints occur. Then, the most important and relevant price differences in space are handled in the market.

What about differences in time? The NordPool participants take part in a price hedging futures market. Due to the volatility of both the supply and demand side, players need to hedge against the risk. In this market, risk lovers and risk averters meet and set up hedging prices for futures and forwards. All available information needed to optimise the value of water over time is settled indirectly through this financial market mechanism. The overall strategy, again, is to equalise the value of water over time.

4. The price formation

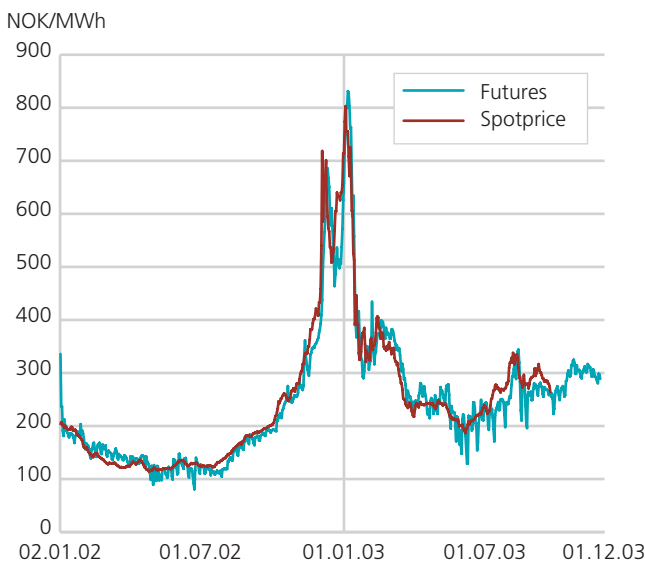
The futures market at NordPool gives information about the market anticipation of the future value of water. If prices are higher in the future (futures) than today (the spot market), it is profitable to store water for production at higher prices later on. Lower production today increases the spot prices. More production tomorrow reduces prices in the future. This optimising behaviour is going on until no arbitrage possibility between periods can be obtained. However, today is higher valued than tomorrow, due to uncertainty and an expected rate of return of investing in storing water, and because there may be some short term marginal costs of storing water. These elements must be adjusted for when comparing futures prices and the day-ahead spot price. The formal relation between futures prices and the spot price can be specified as (see Gjørlberg et al (2003))

$$p_f = (1+r)p_s + w + \varepsilon$$

p_f is the futures price, p_s the spot price, w the storage cost and ε represents an uncertainty element.

In figure 6, we show the development of the average over the 3-month ahead futures prices and the spot price for every day in 2002 and 2003. As the figure shows, the correlation seems to correspond with theory. Whether the futures price is the leader and the spot price the follower seems to vary over the period.

Figure 6. The development of the average 3-month ahead futures prices and the spot price. NOK/MWh

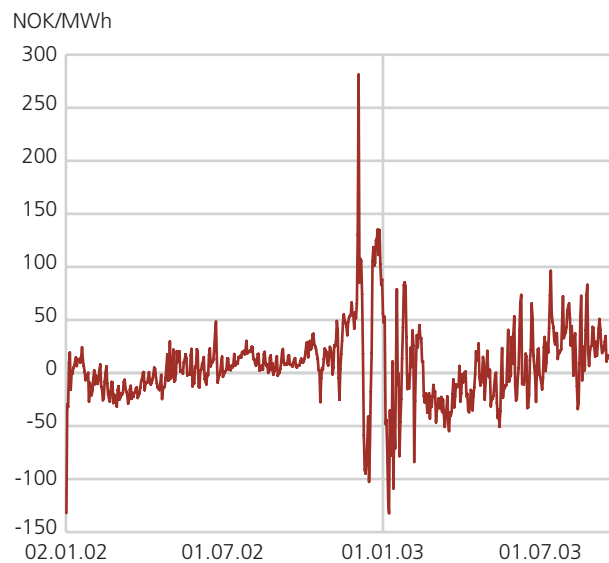


During most of the fall of 2003, the futures price was higher than the spot price as we would expect when uncertainty is normally distributed. From mid-December 2002 to early May 2003 the futures price was lower than the spot price in periods. Uncertainty was high and seems to have varied, perhaps biased downwards. When the snow-melting period started in May 2003, the reservoir level increased, and the normal high futures price compared to the spot price prevailed.

Even though the futures price and the spot price seem to correlate as expected from theory, a closer look at the differences raises important questions about the functioning of the market. Figure 7 shows these differences. For most of the period, the futures prices were about 10-15 per cent above the spot prices. In mid-December, this changed dramatically. Over a short period of time, the difference was almost 35 per cent, and it changed from positive to negative in a matter of days. What can the explanation be? The theoretical relation between futures prices and the spot price described above point at three different elements; the interest rate, the storage cost, and an uncertainty element. The interest rate did not change during this period, neither did the storage cost, as there was no probability of overflow in December. Uncertainty obviously changed. Three elements may be important to explain this change in uncertainty: bank security, an inefficient market and information.

First, since the spot price almost quadrupled in this period compared to the summer of 2002, the absolute price difference became huge in December and January. Thus, the arbitrage possibilities increased enormously. Arbitrage also changed from a bias towards spot to a bias towards futures in a matter of a few days, i.e. a large change in the risk. Second, all agents in the futures market have to place a bank security for the future settlement of the contracts. Since prices in

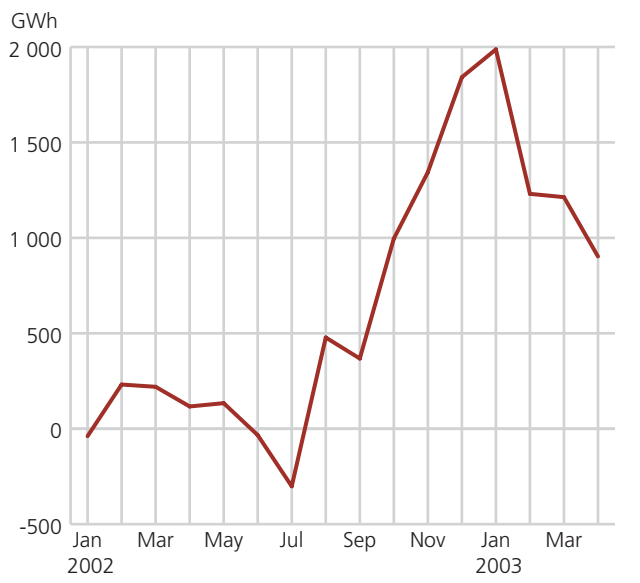
Figure 7. The differences between the 3-month ahead futures prices and the spot price. NOK/MWh



the futures market tripled, the NordPool administrator found it necessary, on a short notice, to increase the bank security level in the futures market. This resulted in some of the market participants facing problems in raising the increased security and even withdrew from the market. Tripling of the prices, increased risk, and increasing bank security levels implied an almost illiquid market for a short period of time. A low number of players then increased the possibilities to exercise market power, both in the spot market and the futures market. The third element is the information problem. Prices normally have a rationing effect on the market. If the authorities consider the price mechanism as insufficient they should regulate the market by other instruments to secure enough electricity throughout the whole winter period. In December, both the Transmission System Operator (TSO) and the Norwegian Water Resources and Energy Directorate (NVE) indicated the possibility of intervention in the supply and demand side of the market. At the same time, there was a huge debate on prices, price formation and possible malfunctioning of the market that also led politicians to launch a range of possible instruments to "make the market work". There is reason to believe that this influenced the price formation in both the futures and the spot market.

From figure 6, we see that the average spot price in 2002 was much lower than the average spot price in 2003. In 2002 the average spot price was just above 20 øre/kWh – approximately the same as in 2001. So prices were not generally high in 2002. Only the last two months of 2002 can be characterised a high price period. The average spot price in 2003 is approximately 29 øre/kWh, which is 45 per cent higher than in 2002. Thus, 2003 is a very high price year, not only because of the high prices in the wintertime 2002-2003 but also because of relatively high and stable

Figure 8. Net exchange of power between the Nordic countries and Europe by month. GWh



prices throughout the year. This of course is a consequence of the relative scarcity of water at the beginning of the year, and only a normal inflow throughout 2003, i.e. the relative scarcity prevails.

5. Did we export too much?

One of the main focuses in the discussion last year was the public allegation that Norwegian producers exported too much power during the fall of 2002, as an effort to raise prices and increase profit during the wintertime of 2003. Producers of electricity do not export. Their obligation is to maximise the value of water, taking all the information they have about prices into account. Producers trade spot and futures at the NordPool exchange on the margin. The NordPool Exchange is an international exchange, i.e. producers and consumers from the Nordic countries meet indirectly through bids and offers. However, producers do not meet individual consumers in this market. They face only the total supply and demand, irrespective of whether the players are domestic or foreign. The result of the market clearing at NordPool is an exchange of power between countries. Export and import then become more of an accounting measure than a delivery measure. What takes place is an exchange of power on a profitable basis.

The statement about increasing production in the fall in order to increase prices in the wintertime implies an accusation that electricity producers exercised market power. As explained in the previous sections, production seemed to follow a profit maximising behaviour in a competitive market. It is hard to point at any exercise of market power throughout this period.

The discussion so far has mostly focused on the export side of the story. Let us take a closer look at what happened with respect to imports and exports from Norway from the summer of 2002 to the summer of 2003.

Figure 9. Net exchange of power between Norway and Sweden. Net export from Norway. NOK/MWh and GWh

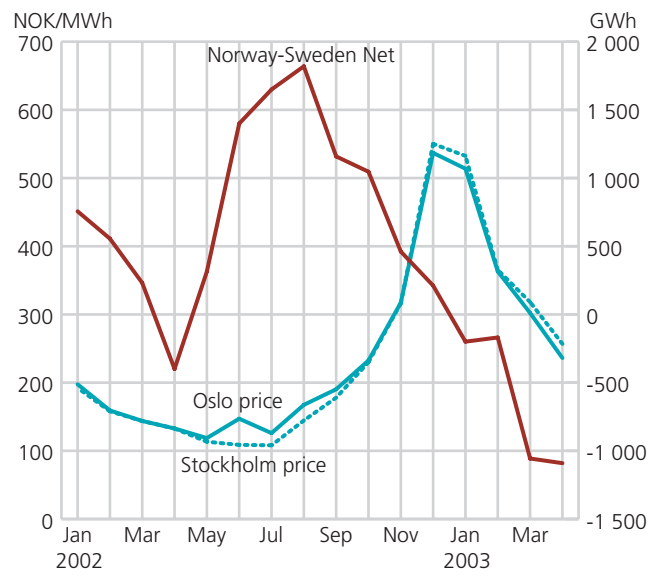


Figure 10. Net exchange of power between Norway and Denmark. Net export from Norway. NOK/MWh and GWh

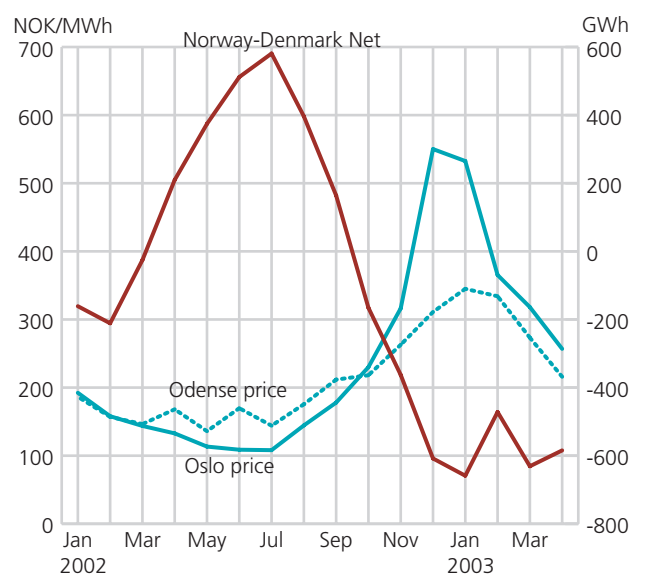


Figure 8 clearly shows that inflows were substantial during the spring and summer of 2002. Prices were low and did not cover the short-term marginal cost in thermal plants in Europe. Eventually, as precipitation and inflow failed, the future value of water increased because of the expected scarcity, prices in the day-ahead market of electricity increased and the profitability of thermal capacities in Europe exceeded zero. The Nordic countries benefited from net imports, which lasted for the whole winter. Thermal plants in Europe helped the Nordic countries with power when water was scarce.

Figure 9 shows the exchange path between Norway and Sweden and Norway and Denmark, i.e. internal net trade between the three countries. From these

figures, we see that Norway was a net exporter when prices were low during most of 2002, until October/November, when spot prices increased sharply. From then on exports changed to imports, a situation that lasted through the summer of 2003. The same pattern goes for the exchange between Norway and Denmark. The most important difference is that while net inflow to Norway from Sweden increased steadily, the imports from Denmark stabilised on a maximum level of approximately 600 GWh a week. This reflects the limited transmission capacity between Western Denmark and Norway. According to Nordel (2003), the transmission lines between these two regions were congested in more than 75 per cent of the time between 1 October 2002 and 31 March 2003, as was the transmission capacity between Denmark and Sweden (inflow to Sweden).

If we accumulate the net export/import figures for these three countries from July 2002 to July 2003, we find that Norway was a net importer of 0.5 TWh. This clearly shows that exchange between countries with different technologies on a profitable basis is to the benefit of all participating countries. When supply of water was plentiful, Norway exported to the neighbouring countries. When supply of water was scarce, the capacity utilisation of existing thermal plants in the neighbouring countries increased, and the exchange changed direction.

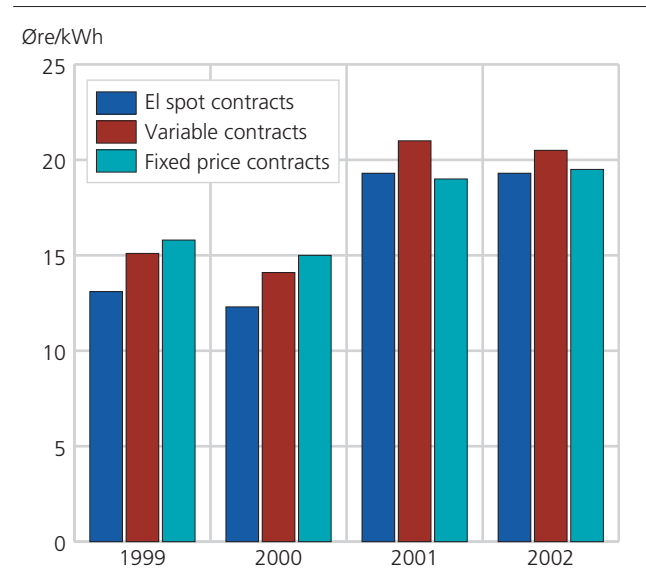
6. Flexibility of domestic demand and the market for contracts

Consumers may be exposed to fluctuations in the spot prices or hedge against the risk by signing fixed price contracts. Two problems then arise:

First of all, hedging against risk is reasonable if the transaction cost of switching contracts is high, if you are a risk averter or your liquidity is low. When spot prices started to increase during the fall of 2002 the media started to advocate fixed price contracts. Unfortunately, this was a little late as optimal fixed price contracts are influenced by the spot price changes and the optimal signing of such contracts is a matter of timing. Besides, signing a fixed price contract implies a combined product; i.e. a combination of an electricity price and an insurance premium. The price in a fixed price contract is therefore normally higher than the spot price.

Second, if everybody hedged against the risk by signing fixed price contracts, the flexibility in the demand side would disappear. When supply is limited, prices in the wholesale market increase. Since everybody is on a fixed purchaser price contract no market response on the demand side helps the market to clear and eventually the market breaks down (cf. the Californian case) in the short run. In the longer run, prices increase as the producers have to take all the risk. Fortunately, many consumers (especially industries)

Figure 11. The average power price by contract type. All consumers except the power intensive industry. Øre/kWh



have signed spot or variable price contracts and actually respond on price changes.

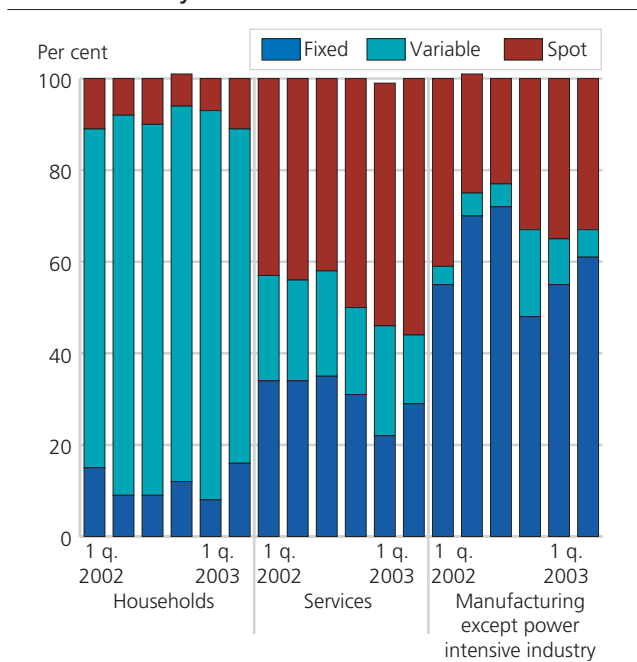
Price contracts, income distribution and market responses were important aspects in the discussion about the functioning of the electricity market last year. Halvorsen and Nesbakken (2003) discuss some income distribution effects. We concentrate on the contracting and the market responses.

6.1. The best contract

Most consumers face access contracts in the electricity market; i.e. they can consume any amount at a fixed unit price, a variable price or a spot price, depending on the type of contract. Some consumers have a combination of fixed price and volume contract (mainly the power intensive industry). These industries face the market price on the margin, as they are allowed to sell back some of the fixed price contracted volume at market prices, and thereby earn a profit. Another type of contract, which is most commonly chosen among households, is the variable price contract. This started out to be a kind of flexible fixed price contract that lasted for some months. Eventually this contract type has become more and more linked to the spot price, as it can be cancelled by both parties 14 days in advance and changed every month. The least typical contract is a spot price contract, which is directly linked to the day-ahead market, with an administrative mark-up.

Figure 11 pictures the average price for the three different kinds of contracts; the fixed price contract, the variable contract and the spot contract, from 1999 to 2002. On average, the spot price contract was the best contract for consumers. The fixed price contract was more expensive, which is as expected under normal circumstances, since when signing a fixed contract,

Figure 12. The share of contracts by type in three different sectors. All consumers except the power intensive industry. Øre/kWh



the supplier takes over a certain amount of risk, which has a price in the market. On the other hand, the supplier also removes some risk in signing such a contract. The graph shows that the net risk sharing has been to the benefit of the suppliers, if they use the spot market when purchasing power for their deliveries. But, we should keep in mind that the figures are averages from several years. Some fixed price contracts may well be better off than the spot contract, depending on when the fixed price contract was signed. As mentioned, this is a matter of timing.

Thus, the variable contract has been the least profitable contract for the consumer over the last two years, while in 1999 and 2000 the fixed price contract was the most expensive one. The reason why the variable contract has been more expensive lately is probably due to a shorter warning period for termination of the variable contract. The variable contract is then closely linked to the spot price. When the spot price increases sharply, it seems as if variable contracts include an even sharper increase, and vice versa. The variable contract then seems to add an important mark-up to the spot price, see Statistics Norway (2003). How this contract survives in the market is an open question. It may possibly be due to lack of information to consumers – i.e. inefficiency in the market. Until recently the Norwegian Competition Authority has only had information about the variable contract offers on their website. In the fall of 2003, information about the differences in the variable contracts, the fixed contracts and the mark-ups on the spot contracts by supplier was also included.

The problem with lack of information is underlined by the fact that the residential sector has been the most eager supporter of the variable contract type, see figure 12. Approximately 85 per cent of the residential sector has chosen this contract type despite the fact that this has been the least favourable both from a price and risk perspective. The service and manufacturing industries¹ seem to have a better mix of fixed and spot contracts and so seem more professional in information gathering than the residential sector. The profits to be earned for the industry on an optimal portfolio mix of contracts is of course also higher, since transaction cost per unit of electricity is less than in the residential sector.

6.2. The market's response

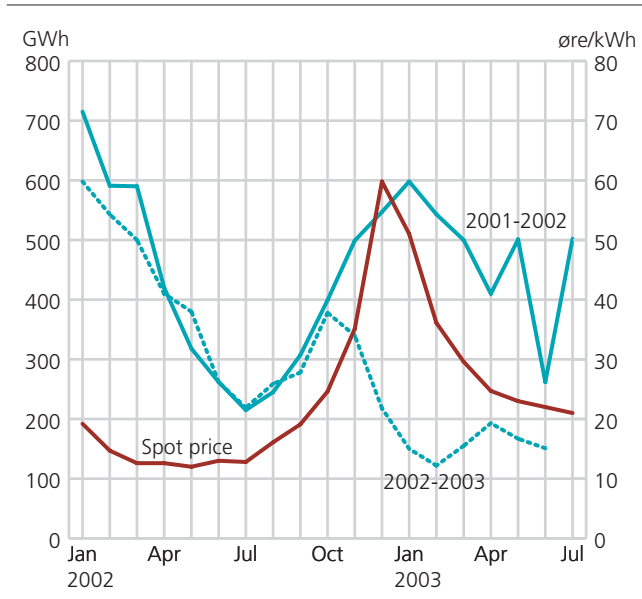
When it comes to the discussion of market response to the increasing prices we divide the market in three with respect to flexibility; the boiler market, the demand in the energy intensive industry and the general consumption of electricity.

The technology in the boiler market is flexible, as the boilers that produce hot water or steam can run on both electricity and fuel oil. The switching is simple, and could be accomplished on an hourly or daily basis. The flexibility in this sector is high. Figure 13 shows that when prices rise in the spot market, boilers leave the market and switch to fuel oil. In the spring of 2002, the boilers followed a normal pattern, decreasing demand as the need for heat decreased. In the fall, the normal development is increasing demand. This was suddenly abrupt by a sharp decrease, as the spot price increased above 30 øre/kWh. Surprisingly, there was still some demand left when prices exceeded 50 øre/kWh. This may be due to lack of maintenance of fuel burners, i.e. switching on a short notice is not possible, or price roof contracts excluding market prices when exceeding a maximum level. In such cases the supplier covers the price risk, and the consumer has no incentive to adjust demand. The total volume effect on demand in the boiler sector is calculated at just above 2 TWh for the periods shown in the graph.

Due to putty clay technology the power intensive industry is not very flexible. This implies that once technology choices have been made the technology is fixed; no substitution is possible in the short term. An advantage of the fixed price contracts in this industry compared to traditional fixed contracts in the general consumption sector is the combination of price and volume elements. This opens up for the possibility to sell power back to the market and earn profit on the difference between the spot price and the contracted price. Since business cycles are important in this sec-

¹ The energy intensive industry is excluded from this graph since they first and foremost use a combination of fixed price and volume contracts.

Figure 13. The spot prices and the boiler market for electricity by month. 2001-2003. Øre/kWh and GWh



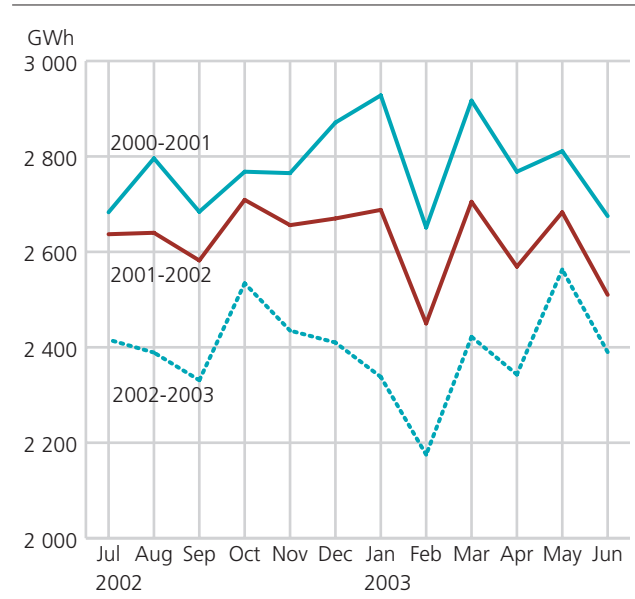
tor, it may be hard to separate the effect from business cycles and the electricity price changes.

Figure 14 shows a large variation in the demand pattern of energy intensive industries between 2001, 2002 and 2003. This may all be due to changes in the business cycle. The graphs also show that the pattern month by month seems to be the same for the three years. The exception is the period October 2002 to January 2003, where demand dropped markedly, while for the same period it increased in 2001 and was stable in 2002. Taking this as the price effect (the spot price started to increase in October and to drop in February), the price response may be calculated at approximately 0.5 to 1.0 TWh.

The general consumption sector (all except boilers and energy intensive industry) typically consumes electricity for a mix of end uses; technical purposes, heating purposes and to some extent processes. Thus, this sector combines flexible and non-flexible demand. Electricity use for heating purposes has been stressed particularly in the debate. Some allege that electricity has some kind of a higher value than expressed in the market, and therefore should be reserved for manufacturing industry processes. It seems however, that the residential sector and the rest of the general consumption sector has a high willingness to pay for electricity (the elasticity of demand is low, cf. Bye, Breivikås and Hansen (2003)).

Figure 15 depicts the demand for electricity from the general consumption sector in 2001-2003. There is a clear difference in demand, especially for the high price period in late 2002 and the first four months of 2003. The sum of differences adds up to approximately 4 TWh for this period. This is also on par with the price elasticities of 0.05 in Bye, Breivikås and Hansen (2003), cf. also Johnsen and Lindh (2001).

Figure 14. The demand for electricity in the energy intensive industry. 2001-2003. GWh



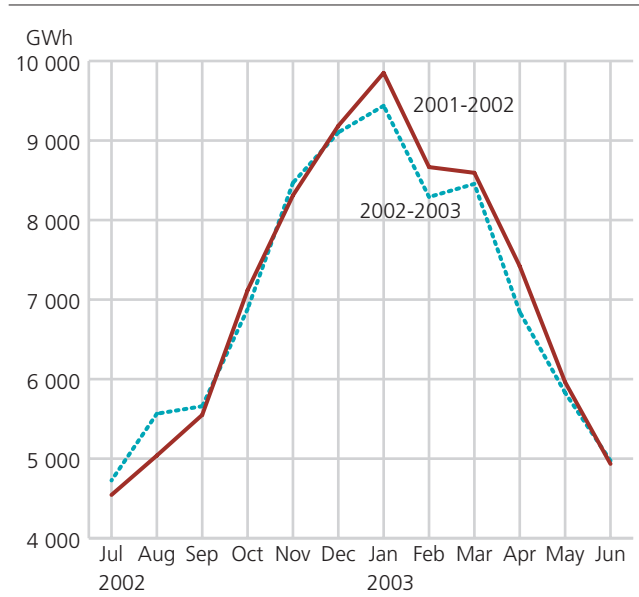
The total price effect in the Norwegian electricity market, from the fall of 2002 until the spring of 2003, is calculated at approximately 7 TWh. This again is approximately one month of electricity use during the snow-melting period of May and June. In the spring of 2003, the lowest reservoir level was at 18 per cent or approximately 15 TWh. According to the TSO, only 8 TWh of this could be utilised effectively in the market. The difference exactly equals the market response we report above. This shows that despite the common view about elasticity of demand being low, the price response actually calculated is very important for the water balance in the electricity market.

7. Are investments in capacity expansion too low?

It seems as if many people are of the opinion that the deregulation of the electricity market implied inefficiencies with respect to the incentives for investment in capacity expansion. To support their view, they point to the fact that since 1991 investments in the Norwegian electricity-producing sector increased the capacity by 4 TWh a year, while demand increased by 13 TWh. As a consequence, net trade changed. In order to explain why this does not imply a failure in the market, we address three issues; what was the reasoning behind the deregulation, what has become the result with respect to return on investments, and what is the future profitability of expanding power production capacity.

The main reason for deregulating the electricity market was to increase efficiency (and social surplus) with respect to three objectives: increase efficiency in the electricity market (equalising prices among consumers), increase efficiency in the distribution and transmission sector, and increase efficiency in capacity expansion (overcapacity comparing prices and cost).

Figure 15. The demand for electricity in the energy intensive industry. 2001-2003. GWh



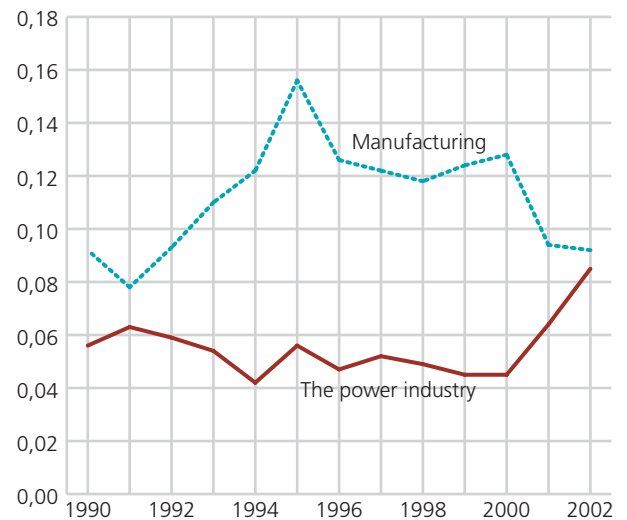
Different upfront studies, cf. Bye and Strøm (1987), Førsund and Kittelsen (1990) and calculations from the suppliers, indicate a net benefit to the society of deregulating the Norwegian electricity market and increasing efficiency at a total of NOK 7-10 billion a year.

Figure 16 shows the rate of return on capital investments in the power sector and the manufacturing industry from 1990 to 2002, i.e. the period after the deregulation of the electricity sector. The figures are based on the national accounts figures for operating surplus and the depreciated replacement cost for each industry. The average rate of return in the power sector in this period is approximately 6 per cent, while the rate of return in the manufacturing industry is well above 10 per cent. This calls for further investments in manufacturing before any expansion of the power sector takes place.

The reason for the low rate of return in the power sector is the overcapacity and low prices under the free competitive market. The overcapacity lasted for many years, and still exists. Several neighbouring countries are linked to the Norwegian market, and these countries also deregulated their markets during the 1990s. They all experienced excess capacity compared to prices and costs. Integrating the markets then implied low prices in the whole region for several years.

We also see that the rate of return between the power sector and the manufacturing industry has narrowed in the last two years. This is due to diminishing excess capacity and a combination of high prices and volumes. In periods with high prices, volumes have not been comparably low, and in periods with large volumes, prices have not been particularly low because of exports. The figure conceals the fact that the rate of

Figure 16. The development of the rate of return on capital investment in the power sector and the manufacturing industry. Per cent.

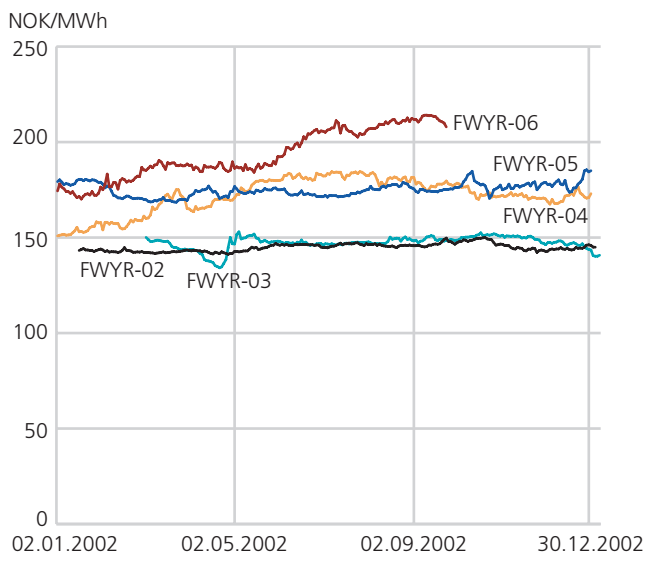


return on the margin is even less than the development shows. The hydropower sector faces an increasing long-term marginal cost of expansion. An optimal investment path should then leave a certain ground rent in the sector, i.e. the average rate of return should exceed the rate of return of alternative investments in other industries. The development of the rate of return in power production explains why almost no investments have taken place since the deregulation of the market in 1991; all investments have to rely on profitability in the market.

At the NordPool market, a three-year forward contract should give an idea about the profitability of future investments in an expansion of the production capacity. Figure 19 shows the development of this forward price contract since 1999. The FWYR2002 then tells us what the market in 1999 anticipated with respect to electricity prices in 2002, i.e. three years ahead. To evaluate these forward prices in an investment approach, we need to know the marginal cost of expansion. In NOU 1998:11, the cost of investing and running a gas power plant was estimated to approximately 20 øre/kWh. This excludes the cost of the negative externalities, like emissions of greenhouse gases, i.e. the social cost is even higher. Since the investment decision is to be taken in a competitive market, the regulatory regime around the greenhouse gas emissions is important. So far, the government has not clarified this. This introduces an uncertainty element in a private sector investment strategy, i.e. it also causes the relevant cost to be even higher than 20 øre/kWh.

We notice that prices in the forward market were very low compared to the unit cost of expansion, with prices increasing as excess capacity diminished, from 15 to 20 øre/kWh for the period of 2002-2005. The forward market thus told the investors that a new capac-

Figure 17. The development of the 3-year forward contract at the NordPool market. NOK/MWh



ity expansion would not be profitable before 2005. Consequently, no investments took place. In 2003, the 3-year forward price has increased to approximately 23-24 øre/kWh. Does this make new investments profitable? Three important factors have to be considered. Firstly, the 3-year forward price probably includes a small mark-up on the price as a consequence of a gradual conversion to a normal reservoir filling. This may imply an embedded underlying downward pressure on the price development for the 2007 forward contract. Second, lately the freight rates for shipping of coal to the Nordic coal thermal plants have increased markedly. This increases electricity prices in the short and medium term. When freight rates are normalised, this could imply a negative shift in prices and profitability of new investments. Third, since 1998, gas prices have increased following the increase in crude oil prices. Since the gas cost is approximately half of the cost of a gas power plant, this implies that prices have to match increased gas power plant unit cost. This may be in the region of 23-24 øre/kWh, i.e. new large investments in increasing the power production capacity on a profitable basis would hardly show up in the next 3-4 years. It should also be added that the government introduces several instruments to increase the power producing capacity based on renewable energy sources, and to reduce demand of electricity for heating purposes. These instruments will then put a downward pressure on electricity prices and postpone the market-based power production investments.

8. Concluding remarks

The Nordic and Norwegian electricity markets were exposed to an extreme primary energy situation during 2002 and 2003. A short-term shortage of precipitation and inflow entailed sharply increasing prices and vigorous discussions about the functioning of the deregulated market when exposed to such extreme

situations. Because the extreme period was concentrated to a few weeks in the fall, it was neither easy for the players to foresee the event nor to adjust fast. Compared to theory, the power market functioned remarkably well during this period.

Norway exported large amounts of power during the fall of 2002, but we imported approximately the same amount during the winter and spring of 2003. This clearly shows the advantage of trade between different supply systems with different properties and short-term marginal cost. We must bear in mind that producers do not export in an interlinked power market, they optimise the value of water in a broad international market, and exchange between countries is simply a consequence of commercial trade in a common pool.

Despite the common view that consumers do not change their demand much when prices of electricity increase, our analyses show that consumers actually adjusted pretty much to increasing prices. The price response equals approximately one month of domestic consumption in the spring. The price response also equalises the difference between the actual reservoir level and the minimum exploitable reservoir level in the spring of 2003. A flexible demand side turns out to be a very important element in a power system facing stochastic primary energy inflow.

One political concern regarding the sharp increases in the electricity prices was the effect on income distribution. Some of this negative distribution effect could have been avoided if consumers had the proper information about risk and contracts. The residential sector almost unilaterally chose the most expensive contract type. A new type of contracts combining a price and volume element would serve as an excellent instrument combining the need for risk hedging and flexibility on the consumer side in a stochastic supply system.

An optimal balance of water over time, when no constraints are in effect, implies an equalising of prices over time. The prices in the futures market and the spot market are then correlated. This has not been the case all the time. The futures market is an important messenger to the spot market. This implies that a well functioning electricity market is based on both a well functioning spot market and an efficient futures market. In some periods one may question the functioning of the futures market, since the market was hardly liquid.

During the past decade, almost no capacity incremental investment has taken place in the Norwegian power sector. This is caused by excess capacity internationally, comparing prices and long-term marginal cost, and a low rate of return on existing capacity. The forward prices on the NordPool market signals that a

new capacity expansion will hardly occur during the next 3-4 years. Many uncertainties, both with respect to the development of prices in the primary energy markets (gas, coal etc) and with respect to the governmental handling of externality issues, put a downward pressure on capacity expansion investments. Governmental efforts to increase the introduction of renewable energy sources and increase energy savings postpone market-based investments in new production capacity.

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