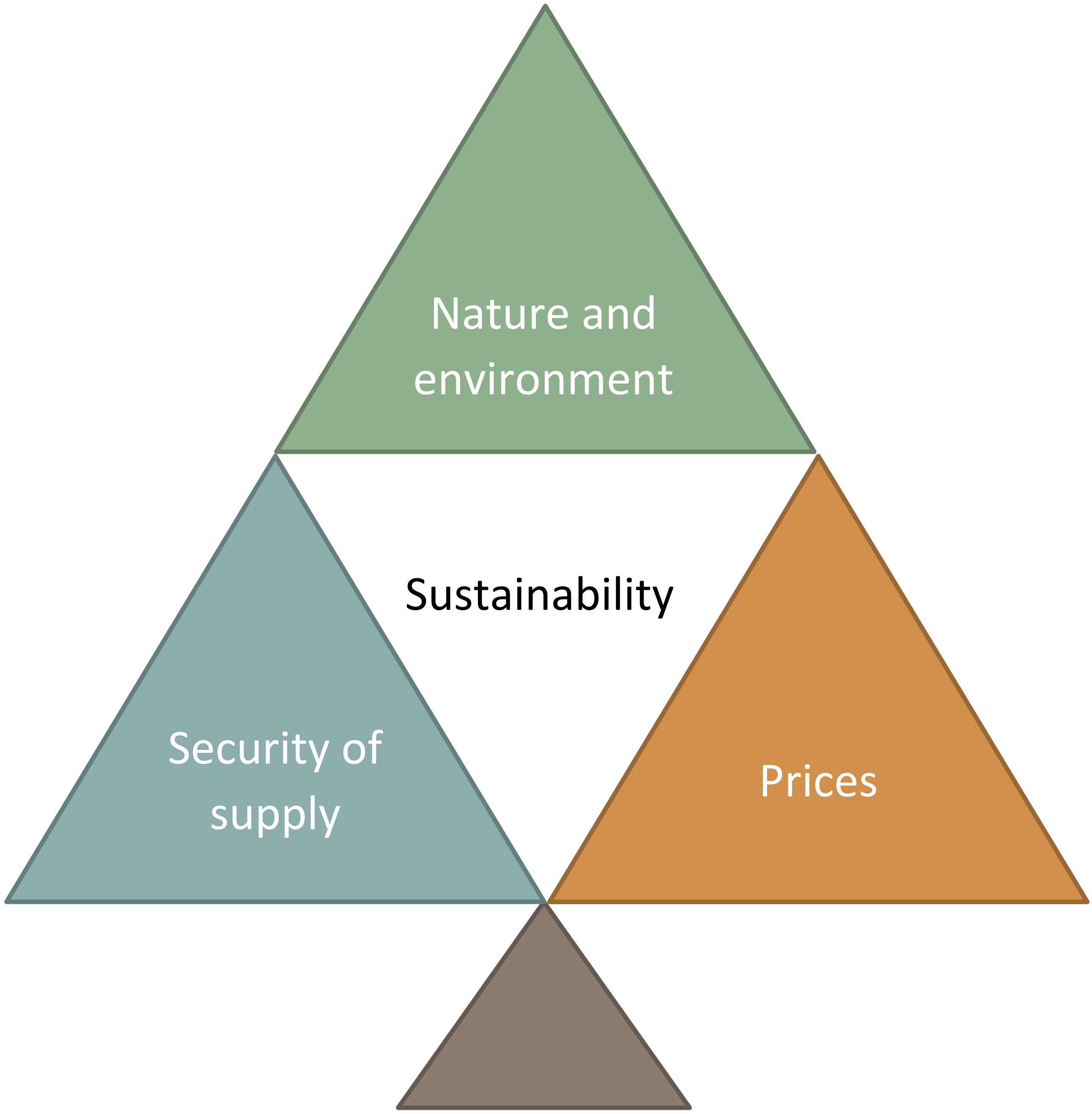
A balancing act



Report from the Electricity Price Committee, 12 October 2023

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Contents

1 Foreword

On 15 February 2023, the government appointed an expert committee to assess the pricing of electricity.

1.1 The committee's mandate

Background

Europe has gone through an extraordinary period characterised by high and sometimes highly fluctuating power prices. Among other things, Russia's military invasion of Ukraine has resulted in reduced access to gas and a sharp increase in the cost of gas-fired power generation, while the closure of major coal and nuclear power plants and other events have affected power price developments. The challenges in European countries have also affected power prices in Norway, particularly in southern parts of the country where the connection to the European power market is greater than in the rest of the country.

High electricity prices have resulted in a significant increase in revenue for electricity producers but have created a challenging situation for electricity consumers. Many countries have therefore introduced programmes to ensure that consumers are compensated for increased electricity costs. For some countries, the compensation programmes can involve significant costs. In the wake of the energy crisis, questions have been raised as to whether it is possible to ensure lower electricity prices for consumers within the current electricity market model, where the principle of marginal pricing is central. More fundamental reforms of the functioning of the electricity market are also being discussed and assessed, including in connection with the European Commission's consultation on electricity market design of 23 January 2023.

In light of the power situation over the past year, the government believes there is a need to review the advantages and disadvantages of the current principles for price setting in different parts of the power market, and assess whether there are measures that can contribute to predictable and competitive prices for consumers. Against this background, the Ministry of Petroleum and Energy set up a committee of experts to investigate various aspects of electricity pricing within the scope of the EEA Agreement.

Mandate

The main task of the expert committee is to investigate and discuss various models that can contribute to more stable, predictable and competitive prices for households, industry and business, and ensure investments in renewable energy.

The basic function of the power market is to ensure secure access to power for consumers and various societal functions at the lowest possible cost, in the short and long term. The models under consideration must be able to ensure Norwegian security of supply in the short and long term, and provide the necessary incentives for production, reservoir allocation, power exchange and consumer behaviour that are in line with this.

The committee will build on relevant work from the Energy Commission.

The Committee shall assess how various proposals for changes to the pricing of electricity in the wholesale market will affect the Norwegian power system, security of supply, incentives to invest in new renewable power production, power exchange and retail prices. The committee will assess how proposed changes in the wholesale market will affect other short-term markets in order to create balance in the Norwegian power market and for future power markets.

The Committee shall describe the relationships between price formation in the wholesale market and the retail market for electricity. Furthermore, the committee shall provide a status description of the competitive conditions and the supply of agreements in the Norwegian retail market, and assess which measures in the short and long term can ensure electricity consumers the opportunity for lower and predictable prices. within the room for manoeuvre in the EEA Agreement.

The Committee shall report on the work on crisis measures and more long-term reforms related to pricing in the European power market, and how the implementation of proposed or discussed measures in the EU and the European countries may affect the pricing of electricity in Norway. The impact will be assessed on the basis of assumed influences from the European market, but also on the basis of whether similar measures were introduced in the Norwegian power system. It will be assessed whether it is rational to introduce alternative measures in response to the EU countries' or the UK's changes in market design.

As part of its work, the committee will assess the effects on the electricity market of current proposals that can result in lower and more stable prices, including

- Proposal to create a separate bidding zone (auction) for electricity transported through international interconnectors
- Proposal for differentiation of spot markets for domestic consumption and power exchange between countries
- Proposals based on a proportion of power production being sold outside the spot market in other types of contracts
- Proposals for measures that can trigger greater consumption flexibility with the aim of reducing the level of consumption demanded during peak hours in the spot market
- Proposed measures to limit exports when the filling level in the multi-year reservoirs deviates from the median filling level (seasonally adjusted)
- Proposals for different types of taxes on power exports

Long-term perspective on power pricing
The committee will discuss the main factors that will affect the long-term price of electricity in Norway and the countries with which we are associated.

The committee will provide perspectives and discuss challenges that the current model for setting electricity prices may pose as the power systems in neighbouring countries increase the share of renewable production. It will consider how to avoid weakening investment incentives for new production, and how to protect consumers and businesses from the largest price fluctuations in such a power system.

Organisation and deadlines
The expert committee shall consist of persons with special expertise in the economic, legal and physical characteristics of the Norwegian power system.

The committee will start its work on 20 February 2023 and will be organised as a writing committee. The committee will also receive secretariat resources from the ministries. The committee must submit its final report no later than 15 October 2023.

1.2 The work of the expert committee

The expert committee has been chaired by Inge Røinaas Gran (SINTEF Energy) and has consisted of Håkon Taule (THEMA Consulting), Petter Vegard Hansen (Refinitiv), Lene Hagen (Volue), Jannicke Hilland (Telenor), Kristin Bjella (Hjort), Markus Hoel Lie (University of Tromsø), Svein Sundsbø (retired), Nina Lillelien (NHO) and Nora Hansen (LO). The secretariat has been led by Jørgen Bjørndalen (DNV) and has consisted of Kaja Malena Remme, Eivind Orset and Ole Svihus from the Ministry of Petroleum and Energy, and Ståle Øverland from the Ministry of Finance.

Between March 2023 and October 2023, the committee held 12 meetings, including three two-day meetings. In addition, there have been various meetings in groups for the different chapters, secretariat meetings and meetings between the head of the secretariat and the committee chair.

In its work to shed light on the issues in the mandate, the expert committee has drawn on the expertise and analytical skills of the organisations in which its members work. The committee has had a Teams meeting with Mathieu Fransen (group leader for grid codes, ACER) to obtain information about their assessment of measures in different EU countries aimed at the extraordinary power situation.

Input
The expert committee has also received written input from Renewable Norway, Hafslund Eco, Federation of Norwegian Industries, Samfunnsbedriftene, Statkraft, Endre Haraldseide, Lornts Havstad, Diderik Lund, Jens Musum, Nils Christian Petersen, Egil Salomonsen, Gunnar Sanner, Rolf Ulseth and Rune Valle.

Legal considerations
The expert committee has had two legal reports prepared by Professor Erling Hjelmeng, University of Oslo, and attorney Gjermund Mathiesen, Kvale Law Firm. The reports are available on request from the Ministry of Petroleum and Energy.

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The expert committee has had an extensive mandate and has had limited time for its work. Within this framework, it has not been possible to thoroughly analyse all issues. The committee concluded its work on 11 October 2023.

With this, the committee presents its report.

Oslo, 12 October 2023

Inge Røinaas Gran	Håkon Taule	Petter Vegard Hansen	Lene Hagen	Jannicke Hilland
Markus Hoel Lie	Kristin Bjella	Svein Sundsbø	Nina Lillelien	Nora Hansen

2 Changing electricity market - overall assessment from the committee

In this chapter, we present the Committee's overall assessment of the electricity market and what can be done to ensure lower, competitive and predictable electricity prices. The Norwegian electricity market has long been characterised by relatively stable and competitive prices. The power markets are changing as a result of both the energy transition in Europe and developments in Norwegian power production and consumption. A number of analyses indicate a sharp increase in power consumption in Norway in the years to come (Statnett 2023, NOU 2023: 3). The committee assumes this.

We must be prepared for prices to increase and become more unpredictable in the future. The core of the committee's mandate is to look at measures that can mitigate these effects. Many measures have been proposed to protect electricity customers from price increases, from major restructuring of the electricity market to the introduction of support schemes. The committee's report analyses the effects of these different types of measures, including price effects, other consequences and barriers to introducing them. The presentation in this chapter is concentrated and brief, and does not do full justice to the scope and nuances of the committee's analyses and assessments. The reader is therefore encouraged to study the report's specialised chapters in parts 1, 2 and 3.

2.1 A balancing act

The power market is influenced by political framework conditions and reflects the needs, assumptions and economic judgements of market participants. What is special about the power market is that it must also relate to the laws of physics. All the time, every second, the power system must be in physical balance. Many thousands of producers and millions of consumers in Norway and Europe must work together and individually to ensure that exactly the same amount of electricity is produced and consumed at the same time. Electricity prices and their variations play an important role as an information carrier to coordinate all these decisions.

The energy market reform, which is based on the Energy Act of 1990, ensured that necessary decisions were moved as close as possible to the production and consumption of power, to the marketplace.

In the Committee's opinion, this decentralised management of the power system, which Norway was a pioneer in developing, has contributed to more efficient utilisation of production resources, lower total costs for power supply and less use of nature for energy purposes than we would have had without such a market-based power system. These are the strengths of the current market model and important features of the energy transition. The disadvantage is that the transition in combination with the market model can have undesirable distributional effects, and that Norwegian consumers are exposed to events and political decisions in other countries. It is not a given that higher prices will lead to increased new production. It is also uncertain whether the price signal is sufficient to fulfil Norway's political ambitions to implement the green transition and ensure that Norwegian electricity continues to provide a competitive advantage for new, green industrial establishments.

The construction of power grids between regions in Norway and to our neighbouring countries in Europe is a consequence of the fact that our power supply is dependent on local weather variations and that consumption needs are often located elsewhere than production possibilities. A system that is dimensioned to cover demand in a normal situation will in some periods have large surplus capacity that can be utilised for export, while in other periods there will be power shortages that must be covered by imports.

We have experienced fluctuating power prices during the period in which the Energy Act has been in force. This is to be expected when power generation is based on natural conditions such as precipitation, temperature and wind, and when we have been exposed to major price variations and events in our neighbouring countries. However, the price fluctuations have not been so great that they have been accepted by households and businesses.

In the 30 years that have passed since the Norwegian market reform was implemented, an increasing number of countries have implemented similar market solutions for their power supply.

2.2 The power price shock

For a number of years, the price level in Norway has generally been lower than in our neighbouring countries, which can mainly be explained by a good power balance based on our natural conditions for hydropower production. Security of supply has been good, with delivery reliability never falling below 99.96 per cent since 1996.

In the last two years, from the second half of 2021, through 2022 and into 2023, a new situation arose. There was an unforeseen and drastic increase in European and Norwegian power prices. The main explanation for this was the energy shortage that arose in Europe due to Russia's attack on Ukraine. In a theoretical and technical sense, the market functioned in such a way that there was no systemic problem in the electricity supply itself, but the distributional effects and social consequences were unacceptably large. So great that most countries chose to implement mitigating measures in the form of various support programmes. No democratic country could accept the economic consequences that the power market has delivered during this period.

The current price crisis is primarily triggered by a war-driven energy shortage. However, there is reason to recognise that the Ukrainian war coincided with a climate-motivated energy transition in Europe. The decision had been made to phase out coal and nuclear power, and these energy sources had begun to be replaced by renewable electricity, particularly from wind and solar power. In Norway, these changes coincided with the opening of two new interconnectors. The war-triggered situation therefore hit Europe and Norway at a particularly vulnerable time when market conditions were changing.

The energy transition, which was already underway, fuelled by efforts to achieve targets for reducing greenhouse gas emissions, was now significantly reinforced by the desire to make Europe independent of energy supplies from Russia. At the same time, the crisis had highlighted the undesirable distributional effects that the current market model can lead to. This has led to extensive debate on the organisation of the power market in the EU. For the time being, however, it does not appear that the EU is rejecting the marginal price model.

Norway and Europe are closely linked, both in terms of the geopolitical situation and climate work. The same applies to electricity supply. The first interconnectors between Norway and other countries were established more than 60 years ago, and for many years power prices in Norway have also been strongly influenced by coal and gas prices in Europe for most of that time.

The power price shock that hit our part of the world has revealed that we are vulnerable to developments in our neighbouring countries. We are aware that we face major challenges when it comes to adapting the market system for electricity to the new energy policy reality.

2.3 Fundamental energy transition in Europe

Political signals and observed actions in the EU and neighbouring countries are clear. Europe is likely to transition from fossil fuels to various forms of renewable energy sooner than originally planned. These are forms of energy that are more closely tied to available space than the more mobile energy carriers gas, coal and oil. At the same time, production will be linked to variable natural conditions and take place completely independently of market prices and consumption wishes. Such an energy transition will require physical, economic and regulatory changes in order for the power systems to fulfil society's need for sufficient energy at all times and at acceptable prices.

We know the technologies that will characterise energy development in Europe in the coming years. The costs are also somewhat known, but there is a great deal of uncertainty here. After a period of falling prices for renewable power generation technologies, land shortages and expensive flexibility solutions may lead to higher costs in the future. It will be particularly challenging to procure enough flexible capacity to ensure security of supply in all situations. Large parts of Europe will most likely have to resort to expensive solutions to cover power demand during periods of low renewable power production. Where power plants based on fossil fuels previously adapted to consumption, Europe's electricity customers will have to adapt to a greater extent to ongoing power production. A system with more renewable power leads to, and creates a need for, greater fluctuations in wholesale prices. Price variation creates opportunities for those who can be flexible with consumption or production, but can be demanding for those who want stable prices, see also chapter 3. Variation and uncertainty increase the financial risk of all investments, both for power generation and for industry.

Norway will be affected by this through treaties, agreements, contracts and physical power connections to neighbouring countries. In principle, Norway has good conditions for flexible power generation through the utilisation of our water reservoirs. However, the capacity of these reservoirs is small compared with Europe's needs. It is therefore important that these reservoirs are managed and utilised in a way that also safeguards the security of Norwegian supply.

Norway's close ties to the rest of Europe, not least in the energy sector, have been emphasised by the geopolitical conditions that are developing through the Ukraine war. Measures in other European countries also have consequences for us. It is therefore important that developments in the energy area in the EU and in relevant neighbouring countries are closely monitored. In the significant energy transition that Europe is now embarking on, Norway must participate actively in European discussions and follow up with relevant measures to safeguard Norwegian security of supply and competitiveness.

2.4 Competitive and predictable power prices in Norway

The committee's mandate centres around three fundamental concepts that are linked to managing this market development, particularly for electricity customers: **lower**, **competitive** and **predictable** prices. These goals are based on Norway's good access to regulated hydropower and ambitions for a green industrial boost. Even with the uncertainty that exists around us, and the agreements and commitments that Norway has entered into, the Committee believes that it is possible to preserve and further develop Norway's comparative advantage in the power sector. In other words, if politically desirable, the Committee believes that it is possible to continue to have lower electricity prices in Norway than in neighbouring countries in the future.

Competitive prices cannot be achieved without sufficient access to power. However, all energy projects have costs, from pure economic costs to nature intervention and other conflicts of interest. In the current situation, lower exchange capacity with other countries can result in more competitive power prices. However, if prices abroad are lower than in Norway, reduced exchange capacity will contribute to higher prices in Norway. Lower exchange capacity and reduced power exchange can reduce overall Norwegian value creation and increase our vulnerability to variations in inflow to the hydropower plants. This highlights the conflicting goals in the energy area.

The power price shock that was the direct basis for the committee's mandate is probably beginning to subside, but it is uncertain what new normal situation we are entering. Average prices in large parts of Europe and Norway appear to be stabilising, but at a higher level and with greater variation than we were used to before the crisis. Norway's competitiveness depends on price developments between regions within Norway and abroad, and the extent of industry-oriented measures in other countries.

The future challenges for the power supply and the power market have not diminished. Power consumption and power generation will change in the future, both in Norway and in Europe. Climate targets and ambitions for green business development require increased electricity consumption. New production will mainly consist of unregulated power. This, together with the fact that we are connected to a Europe in transition, means that the power market in Norway will also change.

The measures discussed by the committee in this report are therefore not just about individual measures that can solve the power price crisis we have now experienced. The biggest challenge going forward is to prevent similar situations from recurring and to create security of supply and socially acceptable and competitive prices in the new energy reality that is being shaped. This is not just a question of isolated individual measures, but of several measures that interact with each other to meet different and as yet unknown future challenges.

Price formation in a market-based power system is entirely dependent on the political framework and conditions within which it operates. Examples of such frameworks include the conditions for new energy production, the development of power grids that remove bottlenecks, regulatory conditions for the production and sale of power and any redistributive support programmes.

2.5 Experts and politics

The experience from the power crisis of the past two years is that it is first and foremost a distribution crisis. In isolation, the Kraft systems functioned as intended, but the distributional effects were unacceptable.

An expert committee can assess connections and consequences, but it should not make value-based choices that determine how burdens and benefits are distributed. This is a political task. Therefore, the committee does not come up with many conclusions about what should be done. The main focus of its work is to analyse the connections in the power system and the effects of various measures.

Nevertheless, the committee would like to emphasise three fundamental factors that stand out in our assessment of the new energy policy reality that is developing: the importance of the power balance, the possibility of changes in regulation and framework conditions, and the need for preparedness and redistribution.

2.6 Three basic conditions

The power balance in Norway and a policy to ensure this is and will be of vital importance for price levels and predictability. Without a strong Norwegian power balance, it will be impossible to ensure competitive and stable power prices in the future. The power balance depends, among other things, on what we do to make energy use more efficient, what investments electricity customers and power producers wish to make and which projects are accepted by society and authorised and supported by the authorities. Measures and factors that affect the power balance are discussed in more detail in chapter 7, 12 and 15.

Although the Norwegian electricity market model has characteristics that will be important in the future, see chapter 14, the war and the need for energy transition have created considerable uncertainty about energy policy globally and in neighbouring countries. It is too early to see clearly whether comprehensive **regulatory measures** can have the desired effect, but we must be prepared for the fact that major changes may be needed in the future to ensure security of supply and predictable and competitive prices. Specific measures are discussed in chapter 16 and 17.

Preparedness for possible redistribution must be permanently in place to be able to handle the undesirable distributional effects of possible extreme events and the consequences of the new normal situation we are entering. The electricity price crisis is being managed through temporary support programmes for households and businesses. Although the current crisis is expected to end at some point in the future and the need for support will decrease, there is reason to expect greater unpredictability and a higher price level in the future. This is discussed in more detail below and in chapter 17.

2.7 General information about the committee's assessments

The committee has analysed a number of proposals for measures aimed at contributing to stable and competitive prices. The proposals come from many sources, including the committee's mandate, input received and statements in the media. The assessments are presented in the report's specialist chapters and are briefly summarised below. The summary and assessments are closely linked to the committee's assessment of the current decentralised market-based wholesale market. In order to explain how the committee has worked, we start with a more comprehensive summary of the assessment of the current market model.

2.7.1 The committee's assessment of the current wholesale market model

The committee has considered other ways of organising the wholesale market than the current decentralised market with marginal pricing. This is discussed in chapter 14. A seemingly simple model for the wholesale market is to retain the decentralised structure, but allow each producer to be paid according to their own bids in the spot market. Experience suggests that this only encourages participants to guess what the market price will be and bid accordingly. The current system rewards producers for revealing their own costs through bids in the wholesale market. In the worst case scenario, payment by bid can lead to greater price variation and higher price levels than the current system, all other things being equal. The model does not reduce uncertainty related to investments and it does not contribute to solving planning tasks, as the current system does. It is unclear how the prices to electricity customers will be set, but there is no reason to believe that the total cost to electricity customers will be lower.

An alternative approach is to divide the market into two or more segments, based on the fact that different production technologies have different costs, as Greece has advocated. For example, unregulated production could be paid according to its total costs, while regulated production continues with the current system. The aim could be to ensure that any extraordinary income such producers may receive under the current system can be more easily distributed among electricity customers in the form of lower prices. In Norway, we have a tax system that has elements of the same, but which safeguards important characteristics of the individual power plant's costs. A significant difference is that we do not have a distribution mechanism as proposed in Greece. Successful implementation of the Greek model could at best result in the same wholesale prices at the margin as would be achieved with the current system and a surplus that in principle corresponds to the revenue from the resource rent tax for hydropower. Alternatively, prices will become more unpredictable and, not least, the uncertainty associated with investments could become greater. It is unclear how the model works if the wholesale price remains below the total costs of unregulated production for long periods. How the surplus is to be utilised does not necessarily follow from the model, but if it is used to reduce electricity prices for buyers, consumption could eventually be higher than with the current model unless a system of quotas is introduced for electricity customers.

A third alternative is to return to the solutions prior to deregulation, for example by making the state itself, or a small number of publicly owned companies, responsible for the operation and planning of power plants in a limited geographical area. It is not obvious that the total costs will be lower, but it may be easier to reduce price variations for electricity customers. Electricity customers' access to long-term contracts will depend on policy. Although consumption will have to adapt to resource availability to a greater extent than before in a power system with a high proportion of wind and solar power, much of this adaptation can be automated. However, this requires control signals that electricity customers or their installations can react to, and the possibility of profitability in actively managing consumption. It is difficult to see how this can be coordinated in practice without varying prices, since we do not have centralised information about which electricity customers can make adjustments when and to what extent.

The above models have been highlighted as alternative ways of organising the wholesale market to deal with distribution issues and ensure predictability. The committee's assessment is that these alternatives cannot ensure security of supply and efficient utilisation of energy resources as well as the current system.

The committee's assessment is that the market-based, decentralised wholesale market for electricity should remain. Wind power and solar energy utilise input factors that have no alternative value. In a power system where unregulated power replaces regulated power plants based on gas or other fuels, consumption will to a greater extent have to be adapted to production. With the current market system, consumers are signalled this through prices. Electricity customers who have flexibility in terms of when they want to use electricity receive a lower average price than customers without flexibility. At the same time, their flexibility contributes to lower electricity prices for everyone.

Alternatives to the current model do not appear to provide better resource utilisation or greater socio-economic surplus. The redistribution sought to be achieved through alternative wholesale market set-ups will in reality result in less redistribution. With future climate change and a more complex power system, the Committee believes that the current model provides the best conditions for ensuring good security of supply and prices that reflect energy supply. However, this conclusion, together with uncertainty about measures in the retail markets in other countries, poses new challenges for electricity customers and emphasises the need for redistributive measures. The Committee's assessment is that redistribution is better handled in the retail market than via the form of sale in the wholesale market, see below and chapter 16 and 17.

High uncertainty and price fluctuations increase the risk associated with investment decisions, particularly for new power generation. It is not a given that the players' price expectations are sufficient to secure the investments needed to realise the energy transition.

2.7.2 Briefly about the committee's assessments of various measures

The committee has assessed around 50 measures. These are presented in detail in chapter 15 (wholesale market), chapter 16 (market failure in the retail market) and chapter 17 (redistributive support).

Measures for the wholesale market
The Committee has assessed several measures that have been proposed to lower wholesale prices, see chapter 12, 14 and 15. In the Committee's judgement, some of these will probably not work as intended. Other measures will have negative effects on value creation in Norway or on security of supply. With great uncertainty about market developments in our neighbouring countries, the impact of several measures aimed at price formation in the wholesale market is also uncertain. A

strengthened power balance and a policy to ensure this will certainly contribute to competitive prices in Norway.

Utilisation of the capacity of interconnectors is a key topic in the power debate in Norway. The outcome of such measures is closely linked to the current power balance in Norway and may have consequences for security of supply. The possibility of achieving a favourable price effect depends on the agreements that have been entered into, and on possible countermeasures from relevant neighbouring countries, see chapter 15.

Measures that limit the utilisation of interconnectors abroad may have a price-damping effect, but at the same time, in most cases, weaken security of supply. Measures that seek to limit utilisation will have no effect on prices. Reduced or future limitation of exchange capacity may contribute to lower prices as long as Norway has a power surplus, but not in a scenario with even greater power surpluses in our neighbouring countries.

In the wholesale market, opportunities for redistribution of risk should be improved. From the end of the 1990s, the organised market for futures contracts (forward contracts) was among the best and most well-functioning in the world. On 18 September 2023, RME announced that it will map the players' opportunities for price hedging in Norwegian bidding zones. In this context, the Committee recommends that consideration be given to whether Norway should follow Sweden's example and ask Statnett to act as counterparty for a limited volume of price hedging contracts (EPAD, see chapter 15.4.9). Effective price hedging for end users requires that electricity suppliers and power companies have good opportunities to adjust their risk exposure in the financial forward market. High activity in the forward market provides suppliers with important information about the value of power in the future, see chapter 8.8.

Good information flow is essential in all markets. In general, the flow of information in the wholesale market is considered to be good, both between players (to the extent that players should and can exchange information) and between players and the authorities. The Commission discusses in chapter 15.4 a number of measures that can provide even better information flow. The MPE's proposed control mechanism covers some of this need, but the Committee would like to point out that better information exchange is generally reasonable and can have a real impact on the market behaviour of the players and result in lower prices in scarcity situations.

Norway has around half of Europe's water reservoirs. In this context, the committee would like to emphasise the importance of the concept of *water value*, see also chapter 7. A qualitatively good water value calculation is essential for realising the value of the regulation of watercourses. Since the inflow to the reservoirs is uncertain, hydropower producers have an uncertain amount of water at their disposal over time. Every day and week, they must therefore choose how much reservoir water to use now and how much to save for later. The individual producer calculates the water values in light of the individual reservoir's characteristics, inflow conditions, regulatory provisions, society's expectations and political requirements, and not least what prices the hydropower producer expects to achieve in the future. Without effective price formation in the wholesale markets, calculating the value of water would be very demanding in practice.

Measures for the retail market

The Commission has analysed the retail markets for electricity, see chapter 8. The Committee has also assessed a number of measures that have been proposed to lower retail prices. Several of these involve greater government involvement in the retail market. Others involve regulation that links the retail price to a mix of wholesale prices and profits from low-cost production, see chapter 14, 16 and 17. Measures to improve the retail market for electricity can contribute to a more well-functioning market, and thus lower surcharges on the electricity price to electricity customers, but measures to rectify market failures in the retail market will not be able to give users a lower price than the underlying wholesale price. Price hedging and various types of fixed price agreements can create predictability for electricity customers, but the price level will still be determined in the wholesale market.

For most electricity customers, it will be challenging to assess the risk of price changes and to save for unforeseen price increases. Although fixed-price contracts may result in higher electricity costs over time, for many electricity customers it may be more important that costs are stable. This can be achieved through fixed price contracts, contracts that mix fixed price and spot price, or schemes that equalise the customer's payments, see chapter 16.4. However, periods of extreme prices are not very suitable for price-securing consumption. Although an increased element of fixed prices for end users may, in isolation, reduce the demand side's adaptation to the resource supply as reflected in spot prices, all customers should have equal opportunities to choose the degree of price hedging or stabilisation of their energy costs. The power system's need for flexibility on the consumption side is not more important than the electricity customers' need for an agreement customised to their needs.

Electricity suppliers have a poor reputation in Norway. The market has a high degree of competition, but there are still clear information problems and some suppliers appear to have very high profits. It is difficult to find effective measures to prevent customers buying or being invoiced for additional services they do not need, or not understanding the terms and conditions of the electricity contract, as examples of this are constantly emerging. This is a risk particularly for vulnerable consumers. A number of measures have been implemented in recent years, and new ones have been announced. Strengthened enforcement of consumer protection regulations and increased use of sanctions are relevant measures.

Redistribution and preparedness

There is great uncertainty about future electricity prices. The competitiveness of Norwegian companies is affected by both price differences abroad and price differences within Norway. A Norwegian power surplus will contribute to more predictable and competitive prices abroad, but is not a quick and risk-free way to achieve this goal, see chapter 12. In a situation with a power deficit, measures to improve the wholesale and retail markets will not ensure competitive prices. Long-term measures such as grid development and increased power generation can also reduce price differences between regions. Measures for the wholesale and retail markets can provide better access to price hedging, but greater price variations also make price hedging more expensive. This emphasises the need for various forms of support, although support measures also affect consumers' adjustments and, through that, the power system.

The energy transition increases the risk of periods of unusually high wholesale prices, which initially lead to unacceptable distributional effects. Strategies for extreme periods should be based on redistribution in the retail market, not changes in the wholesale market. The design can be done in several ways, while still emphasising maintaining incentives for flexibility and reduced energy use, see chapter 17. The state aid rules provide a framework for the possibilities of providing electricity subsidies to businesses (Hjelmeng 2023, Mathisen 2023).

The current electricity subsidy schemes have been criticised for being too broad and too narrow in scope, and for weakening the motivation to save energy at a time when resources were very scarce. The scheme has redistributed very large sums of money. Much of this has gone to households with good finances, while it is uncertain whether vulnerable groups have received as much support as they have needed. Support for businesses has been limited, while the voluntary sector has been partially compensated for increased energy costs. Nevertheless, the Committee would like to point out that it is better to have an imperfect system than to leave the consequences of the type of events that hit Europe in autumn 2021 and beyond to the individual electricity customer. Towards the end of 2021, we found ourselves in a situation with power prices that would have had unacceptable consequences for a number of electricity customers.

If we end up in a situation with a power deficit and increased prices, measures to improve the wholesale and retail markets will not be sufficient to counteract the resulting price increase. To maintain lower and competitive prices in such a situation, the alternative will in practice be some form of redistribution. The room for manoeuvre to redistribute revenues from power generation to electricity customers is limited by pan-European market and state aid rules. At a time when other countries in Europe must also prepare for the changes resulting from the energy transition, these rules may change. European countries may choose different strategies and solutions that are not necessarily favourable to Norwegian electricity customers. Norwegian authorities and stakeholders should consider how they can work to develop common European solutions that can safeguard Norway's security of supply and competitiveness.

For businesses, there is a risk that other countries in Europe will implement unilateral measures to reduce electricity prices, thereby weakening Norwegian competitiveness. The Committee believes that Norway needs ongoing and openly accessible monitoring of the market conditions around us in general and for the EU in particular. Many players do this to a greater or lesser extent under their own auspices. However, the activities are fragmented, and the extent to which knowledge is shared openly varies. The smaller players, including most energy companies and the vast majority of electricity customers, have no real opportunity to monitor changes in European regulations or whether individual countries introduce measures that favour competitors of Norwegian businesses.

One response to this could be permanent and targeted research on regulatory and market developments in Europe, another could be that RME, for example, regularly presents status and analyses according to a fixed pattern. As part of its regular tasks, ACER regularly publishes reports from its monitoring of the wholesale market for electricity, the wholesale market for gas and the retail markets for various energy carriers.

2.8 Lower, competitive and predictable prices?

Norway is well placed to achieve relatively low, competitive and predictable prices. While other countries are going through a major restructuring of the power market, we already have a power system based on renewable energy and an efficient market system. We have good resources for production and also relatively cheap sources of flexibility. But restructuring in both Europe and Norway, and barriers to new production, mean that the power market is changing and price levels and predictability are changing. The committee's report shows that the solutions for dealing with this are complex, require political considerations and continuous monitoring of the effects of changes in the power market for Norwegian players.

Several of the measures in the report are related to improving existing markets and do not require major regulatory intervention. These measures can contribute to lower and more predictable prices without major consequences for the power system as a whole. In particular, the measures to provide better access to price hedging, both through better futures markets and a better market for fixed price agreements, can contribute to access to more predictable and stable prices within a relatively short period of time.

However, measures to improve the markets and increase price hedging will not result in significantly lower price levels or ensure that prices are competitive. There are measures that can result in lower price levels, both in the wholesale market and in the retail market. However, measures in the wholesale market require major regulatory restructuring and may have negative consequences for the power system and security of supply. Redistribution measures should therefore preferably be implemented in the retail market. At the same time, support measures in the retail market have negative effects that must be taken into account. For businesses, any support measures must be assessed against pan-European state aid rules. For measures aimed at households and other non-competitive operators, there is considerable room for manoeuvre. More effective regulation of the retail market is important, but will not have a major impact on the price level.

The Committee's assessments show that all measures that have a significant price-cutting effect and that can also be implemented in the short term must be weighed against the consequences and costs they entail elsewhere in the market and for society in general.

To ensure low and competitive prices in the long term, and also to protect Norwegian consumers from the largest price fluctuations, the most important measure is a policy to ensure a lasting power surplus. Achieving a strong power balance is a long-term measure and requires a number of political choices, including those related to land use, natural interventions and any need for support programmes.

Norway is an energy nation. Although we have much in common with other European countries, we also have unique opportunities and challenges. It is important that Norway has research and education centres in the energy field at an international level in areas of great importance to Norway. The committee has not made its own assessments of knowledge needs, but points in this context to the independent strategy organisation Energi21. Energi21 was established by the MPE to advise on thematic research and innovation programmes in renewable energy and climate-friendly energy technologies.

2.9 Overview of the committee's report

The technical chapters are organised in three parts. In part 1, we explain in chapter 4 what it was that hit us two years ago. In chapter 5 we explain the tasks and roles of the many different players in the electricity market. Although we have one electricity market, in practice we have many sub-markets with different functions and even more prices - this is explained in chapter 6. In chapter 7 the price formation in the spot market is explained and we provide an overall assessment of this. The retail market is explained in detail in chapter 8.

The aim of Part 2 is to describe some key features of the changes in the electricity market. Chapter 9 provides a brief overview of some key legal acts. The relationship between climate policy in Europe and the electricity market is discussed in chapter 10. In chapter 11 we provide a thorough and chronological review of the work on crisis measures and reforms in Europe. To illustrate the uncertainty of future developments, the committee has created four scenarios. These are presented in chapter 12where we also discuss the importance of interconnectors and the power balance for price formation in Norway.

In the final part of the report, in chapter 13 we review the methodology for the subsequent assessments of various measures. In chapter 14 we discuss the characteristics of current and alternative market models in light of a very high proportion of renewable energy with low or no marginal costs. Proposals for measures to improve the wholesale market are summarised in chapter 15. Proposals that can reduce any market failure in the retail markets are discussed in chapter 16while issues related to different types of electricity subsidies are discussed in chapter 17.

3 The committee's understanding of the mandate

Although the mandate is perceived as clear and unambiguous by the committee, we would like to explain how we have interpreted certain aspects for the sake of order.

Expert committee to assess the pricing of electricity - the main task
The main theme of the committee's work is electricity pricing. The main task is to assess alternatives and measures that can contribute to low, competitive and predictable prices. In the mandate, the main task is formulated as follows:

> *To investigate and discuss different models that can contribute to more stable, predictable and competitive prices for households, industry and business, and ensure investments in renewable energy.*

The expert committee interprets the mandate to mean that the committee is to assess the effects on the power system of various measures to ensure low, competitive and predictable prices. The basis for comparison is primarily perceived as the power prices in other countries and secondly as the power prices we would otherwise receive in Norway as a result of the current framework for the power market.

Furthermore, we understand that the mandate focuses on analysing the effects of various measures, but not necessarily making recommendations on what should and should not be implemented. The committee has nevertheless taken the liberty of pointing out some key issues, cf. the main message as presented in chapter 2.

The mandate also states that the committee is to describe the mechanisms behind price formation in the electricity market.

On this basis, the committee has chosen to work along three axes:

- Describe the current system and organisation
  Part 1 of the report is a comprehensive description of the wholesale and retail market as it stands today.
- Describing the way forward
  Part 2 of the report describes a number of key developments in Norway as well as in neighbouring countries, with an emphasis on what will affect electricity prices in Norway in the years ahead.
- Analyse various measures Part 3 of the report discusses a large number of proposals and ideas for organising or regulating the electricity market in a different way than today. The mandate lists a number of proposals for the expert committee to assess the effects on the electricity market. The expert committee assumes that the mandate does not prevent the committee from assessing other measures in addition, including other proposals that have been highlighted in the public domain. There are therefore a significant number of measures that have been described and assessed.

The power market and society
The desire for lower, competitive and predictable prices may conflict with a goal of socio-economic profitability. For example, socio-economically profitable interconnectors may, under certain circumstances, lead to higher prices than the starting point. Measures to strengthen the power balance may conflict with respect for nature and cultural practices. We realise that it is not the committee's task to take a position on the conflicting objectives inherent in the issues the committee

has worked on. On the contrary, we have interpreted the mandate as an aim to shed light on the effects of various measures so that political authorities can make informed choices.

When the committee has assessed various measures, we have therefore endeavoured to describe their effects on prices and price formation. Can the measure lead to lower, competitive and/or predictable prices? Does the measure, or its effect on prices, have other effects?

The Energy Commission
The mandate specifies that the expert committee will build on the Energy Commission's report (NOU 2023: 3). The committee's work shows that the power balance in Norway, and in neighbouring countries, is of great importance to power prices in Norway. With the reference to the Energy Commission's work, the committee assumes that we have not been asked to describe how targets related to the power balance can or should be achieved.

The EEA Agreement
The mandate states that the expert committee shall assess which measures in the short and long term can ensure electricity consumers the opportunity for lower and predictable prices, within the room for manoeuvre in the EEA Agreement.

The Committee recognises that it does not need to impose strict limitations on the measures to be assessed or evaluated by the Committee, but the relationship to the EEA Agreement will be one of several considerations in the assessment of the measures. In the analyses of various measures, we have therefore emphasised assessing how the measure may affect electricity prices if it is implemented. For the measures that we believe are relevant, we have made an overall assessment of which EEA obligations the measure may conflict with and which may thus be an obstacle to implementation. To support this, the committee has also obtained two legal opinions, which have been used in the analyses. The aim of this approach has been to assess how the measure could have worked if it had been implemented as described.

Conceptual understanding
The mandate uses different terms for the price. The Committee considers stable and predictable to be synonyms in this context. Competitive prices are defined as prices that are lower than in countries with which it is natural to compare ourselves, see also chapter 8.10. The terms low and lower are perceived as a reference to the prices we have seen during the electricity price crisis that started about two years ago, but also to the prices we are likely to see if the measures under consideration are not implemented.

The mandate states that the expert committee is to assess models that can ensure the short- and long-term security of supply in Norway. In this context, models are perceived as measures initiated by the authorities.

The expert committee will also assess which measures can ensure lower and predictable prices for electricity consumers in the short and long term. Furthermore, the committee will discuss the main factors that will affect the long-term price picture for electricity in Norway and the countries to which we are connected. The distinction between the short and long term is not precise, but relates to whether the players have time to make investments related to the production, transport or consumption of electricity. The short term is the power system as it is 'now', while the long term can mean from 5-10 years ahead until the energy system in Europe has been transformed in 30 to 40 years.

The committee uses the words electricity and power so that power generally refers to the wholesale market and electricity to the retail market. However, if the reader is in doubt, the context is crucial.

Part 1: Suddenly the power market was unlike anything we'd seen before

Many people have an image of the electricity market as unusually complicated. The Committee agrees that many aspects of the power market and not least price formation can be difficult to understand for those who have not spent years of their lives in this area. One important reason for the complexity is that the power system must be in balance at all times. Production and consumption must be equal at all times throughout Norway and Europe as a whole. Because electricity travels almost at the speed of light in the wires, this means every millisecond. This does not happen by itself. On the contrary, this task is solved through active co-operation between a number of players. Separate markets have been established for this. This is the main topic of Part 1 of the report, where we describe the power market in detail. One aim is to make the power market a little more accessible to people other than experts and industry professionals.

The electricity market has clear similarities with most other markets - such as reduced supply or increased demand leading to higher prices, and vice versa. Another similarity is that changes in prices cause both suppliers and buyers to consider whether they should change their behaviour. If prices rise, producers will ask themselves whether they should increase production, for example by producing less at a later date (relevant for hydropower with reservoirs), or expand production capacity (expand existing or build a new power plant). Similarly, (some) consumers will ask themselves whether it would be beneficial to reduce consumption temporarily, or whether they should postpone or shelve plans for new future consumption. Prices can thus be interpreted as the factor that ensures that supply and demand are equal.

A third similarity is that even though the product is the same, a distinction is often made between the wholesale market and the retail market in analyses and in publicity. In the wholesale market, larger quantities are sold in each transaction - for example, a number of pallets of flour - while in the retail market, the same product is sold in smaller units, such as a number of packages or kilos of flour. For both flour and electricity, there will be a correlation between prices in the wholesale market and in the retail market. Conditions in the wholesale market can affect the retail market - and vice versa.

To emphasise that we are talking about two (slightly) different markets for the same product, the Committee will preferably use the word **power,** or electric power, to describe the product sold in the wholesale market, while the word **electricity is** used for the retail market.

In Chapter 4, we provide a summarised overview of electricity price developments in recent years. We continue in Chapter 5 with an overview of the roles played by different players in the electricity market. In Chapter 6, we explain how different parts of the electricity market are interrelated and how price formation takes place in practice. Chapter 7 explains why the wholesale market is divided into different bidding zones (called price zones by some) and shows the connection between power exchange, power prices and security of supply. This section concludes with a thorough analysis of the retail market for electricity in Chapter 8.

4 What happened?

In Norway, we have never before seen such high power prices as in southern Norway over the past two years

In the past, we have had relatively high prices in the wholesale market for electric power during certain hours or for shorter periods. In some years, we have had extended periods of low inflow to the hydropower plants (dry years). This has led to periods of relatively high price levels in Norway compared with other countries. For example, in the first part of 2010 and 2011, prices in Norway were almost twice as high as in Germany. We have also previously experienced short periods of very high power prices, for example on 17 December 2009 from 16:00 to 18:00, the power price was over 1400 EUR/MWh throughout the Nordic region except in Eastern Norway (NO1) and Jutland (DK1), where the price was 40-50 EUR/MWh.

Nevertheless, electricity prices both in the wholesale market and for various end users have never been as high for as long as in southern Norway (NO1, NO2 and NO5) from autumn 2021 to summer 2023. From July 2023, prices fell in NO1 and NO5. In September 2023, these areas had the lowest average price ever. Prices in NO2 have remained relatively high in NO2 (which roughly covers Vestfold and Telemark, Agder and Rogaland) during the same period. During this period, power prices have been very high throughout Europe, with the exception of Sweden and Northern Norway.

Although prices have been significantly higher than we have ever experienced before, prices in southern Norway have been among the lowest in Europe during the same period. The difference between power prices in southern Norway and Germany has never been greater than in 2022. Figure 4- shows the average price per month for Scandinavia and the average of German, Dutch and French electricity prices. The coloured area shows the difference between the price in Southern Norway and the Continent.

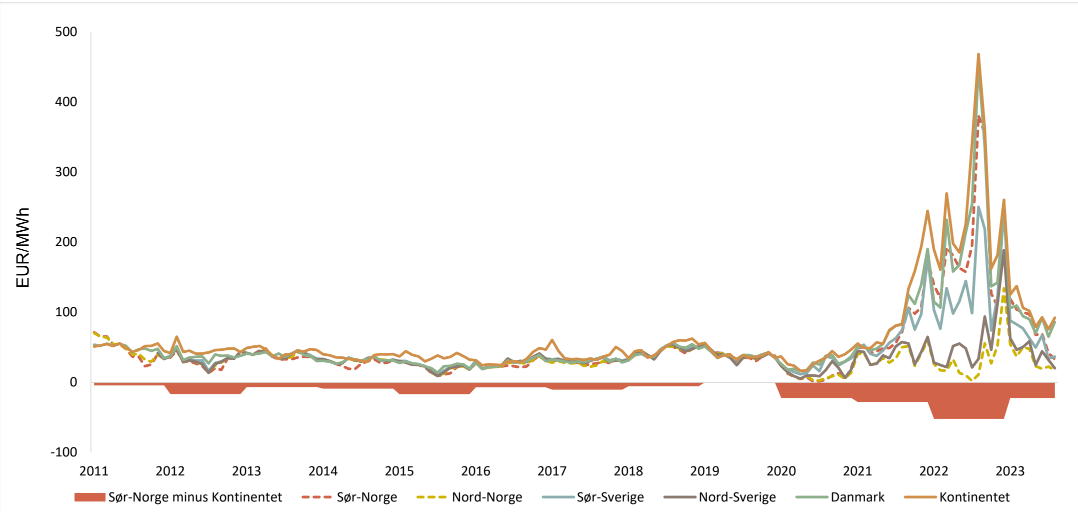


Figure 4- Price development from 2011 to August 2023 (Source: Nord Pool)

The reasons for the highly unusual prices are many - gas prices being the most important

Electricity prices vary from hour to hour. For a detailed description of how power prices are determined, please refer to chapter 6 and 7. In this chapter, we point out the most important reasons for the dramatic price movements in southern Norway since autumn 2021. The main reason was a sharp rise in the price of natural gas in Europe and how this propagated to the Norwegian power market via power prices in Europe.

In autumn 2021, energy prices in Europe began to rise, after a prolonged period of lower prices caused by lower energy demand during the COVID pandemic. In October 2021, gas prices in Europe were 400 per cent higher than in April 2020, while electricity prices had risen by 200 per cent over the same period. High prices in global gas markets, and particularly high demand for LNG, were identified as key drivers. At the same time, the EU countries' own gas production was declining, and the low gas prices throughout the pandemic had led to fewer investments in gas globally, which in turn contributed to a shortage in the market in autumn 2021. Following Russia's full-scale invasion of Ukraine on 24 February 2022, Russia has sharply reduced gas deliveries.

At the same time, it was clear that Russian gas exporter Gazprom failed to increase its gas exports to Europe beyond its contractual obligations, which could have been expected in a situation of high prices. The EU entered the winter of 2021/22 with very low gas stock levels compared with previous years, and with particularly low levels in Russian-owned storage facilities, see Figure 4-. EU gas storage facilities are filled during the summer months and depleted during the winter months, and have a total storage capacity of approximately 1,200 TWh - equivalent to more than 13 times the total storage capacity of Norwegian reservoirs. In Europe, gas storage facilities are very important for meeting increased demand for energy for heating in the winter. The surprisingly low volumes from Russia helped to put pressure on gas prices.

Figure 4- shows that Gazprom's gas storage facilities in Europe had particularly low fill rates before autumn and winter 2021/2022, after they were not filled during the summer 2021 filling season. The average fill rate in Gazprom-owned gas storage facilities was 26 per cent in October 2021, compared with an average of 75.5 per cent in gas storage facilities owned by other operators.

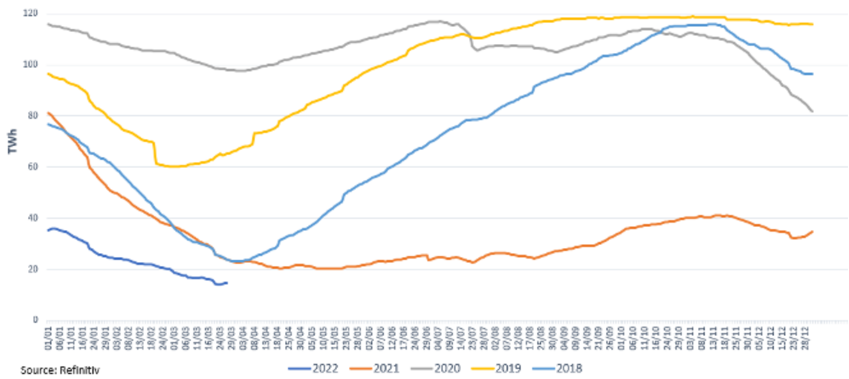


Figure 4- Fill rate in gas storage facilities controlled by Gazprom, January 2018-March 2022 (Source: Refinitiv (2022), [Reuters](#))

Figure 4- shows that Europe entered 2022 with record-low levels in gas storage facilities. The total fill rate was 62 per cent at the end of 2021, compared with an average of around 80 per cent in previous years.

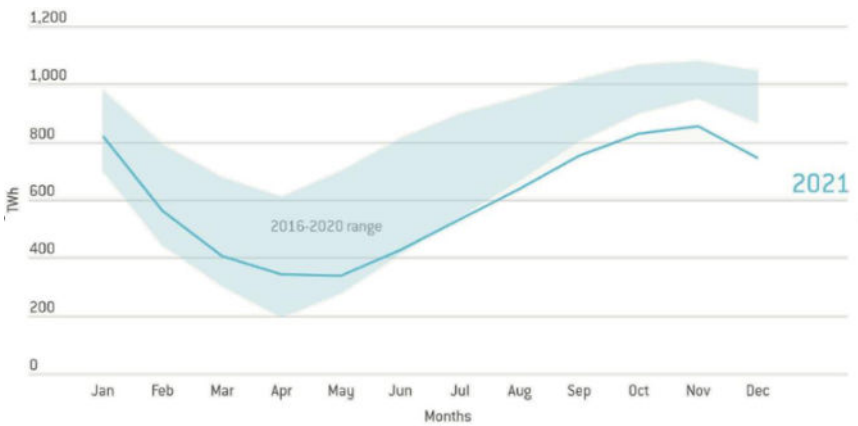


Figure 4- Total gas utilisation rate in Europe, 2021 vs. 2016-2020 (Source: [Bruegel](#) (2021), based on data from [AGSI](#)).

Gas prices and power prices are linked
Figure 4- illustrates the role of gas power in price formation in the European wholesale market in a situation where gas power is needed to meet total demand. The producers have different production costs and bid in volumes at different prices. Power that is bid in at a low price is prioritised first. The market price, which all producers receive for their power, is determined by the most expensive volume needed to meet demand. This is the marginal bid. The market design is called marginal pricing or "pay-as-clear" and is common in both regulated and unregulated markets.

In Europe, the marginal supply often comes from gas power, especially during the hours when demand is at its highest or supply from other sources is low.

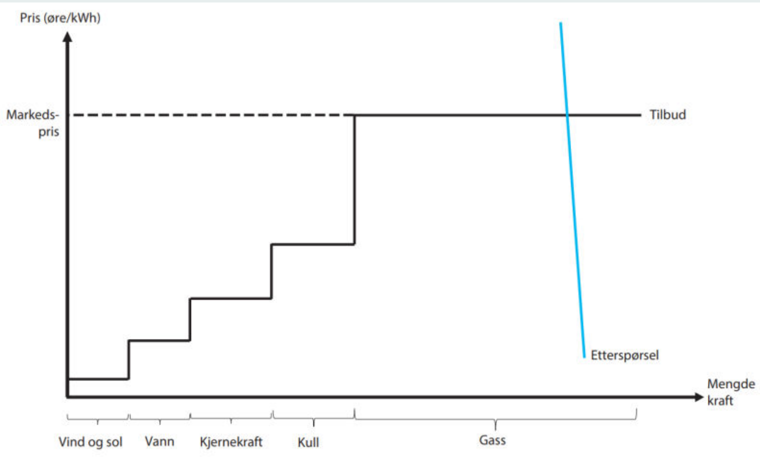


Figure 4- Schematic illustration of price formation in the European wholesale market for electricity (NOU 2023: 3)

Figure 4- shows the spot price for natural gas on the continent and the spot price for electricity in NO2.

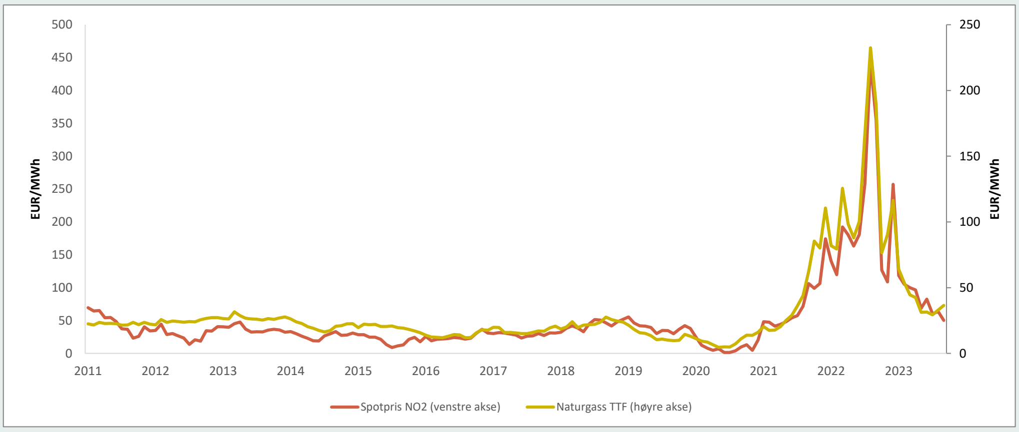


Figure 4- Spot price for European gas (TTF) and spot price for power in NO2 from 2011 to September 2023 (Source: Nord Pool, S&P)

Several other factors contributed to amplify the effect of global gas prices and Russia's reduction of gas exports to Europe (the order does not indicate relative importance):

1. The coronavirus pandemic that started towards the end of 2019 initially led to a fall in global demand for energy, but consumption picked up again during 2021. In particular, demand for gas rose quite sharply. A cold winter and hot summer in 2021 had required energy for

heating and cooling, while renewable production from hydro and wind power in particular had been low during a windless and dry summer.

2. In Europe, the EU's quota system for CO_2 emission rights was for many years characterised by low prices, i.e. 5-10 EUR/tonne CO_2 . An important element of the EU's quota system is that the allocation of quotas will decrease over time. In isolation, this contributes to the increasing value of these quotas, which in turn increases the cost of power generation based on fossil energy sources.

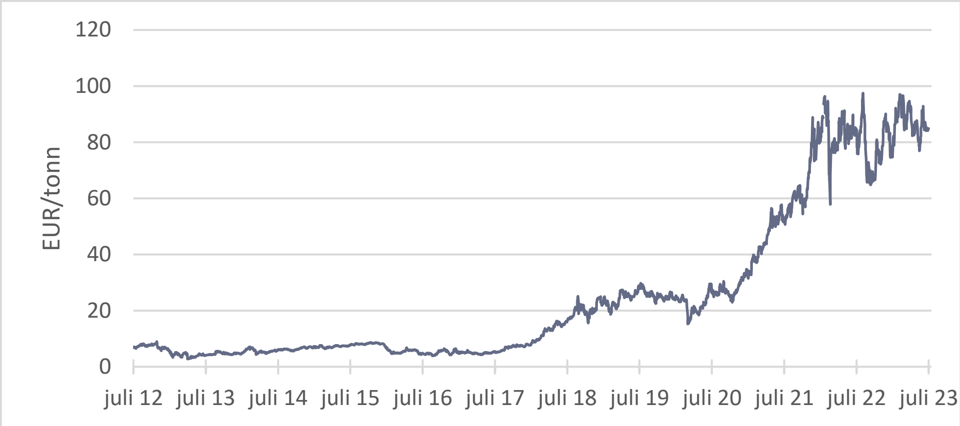


Figure 4- 6 Market price for European emission allowances (ETS) (Source: EEX, Montel)

3. As a result of increasing scarcity of gas, the consumption of coal for power generation in Europe increased. Since power generation based on coal leads to approximately twice as much greenhouse gas emissions as power generation based on natural gas, the value of EU emission allowances increased more than the planned tightening of the allowance market alone would indicate.
4. The drought and heatwave in Europe in the summer of 2022 further contributed to the challenges in the power market. Europe recorded the lowest groundwater level in 500 years. Low water levels in rivers on the continent created challenges in transporting coal to coal-fired power plants and cooling water to thermal power plants based on coal, gas or nuclear power. With limited access to cooling water, the power plants cannot produce at full capacity. At the same time, demand for electricity for cooling became high due to high temperatures.
5. France's nuclear power production was significantly lower than normal and expected in 2022. In addition to extensive planned maintenance, several and more extensive faults were discovered, particularly in the cooling systems of a large number of nuclear power plants.

Norway is only indirectly affected by the challenges mentioned above. The indirect connection is that the power exchange with our neighbouring countries depends on the observed and expected price level in the neighbouring countries, which in turn depends on factors such as those discussed above, cf. chapter 6 and 7. We therefore continue with a look at specifically Norwegian conditions (the order does not indicate relative importance):

6. In 2020 and 2021, exchange capacity to neighbouring countries increased, first with NordLink (1400 MW connection between Norway and Germany) and then with North Sea Link (1400 MW connection between Norway and the UK). Although the wholesale market players have long experience of how to take exchange capacity into account, the capacity increase was larger than anyone had relevant experience with. It is therefore reasonable to assume that the size of the capacity increase has created some uncertainty that may help to explain the price development from autumn 2021 onwards. See also chapter 7 for a more detailed discussion of what foreign trade means for price formation in Norway.

7. In the face of rising power prices on the continent in late summer and autumn 2021, Norwegian hydropower producers concluded that the value of production 'now' (i.e. in late summer and autumn 2021) had a higher social and commercial value than storage until later in the winter/spring of 2022. In hindsight, it is clear that these analyses did not sufficiently take into account either the possibility of the upcoming Russian invasion of Ukraine or price developments in the gas and power market on the continent beyond 2022. The forward market, with market prices in the summer and autumn of 2021 for power contracts with delivery during the winter of 2021/2022, indicated that prices would fall from the autumn and into the winter. This price picture supported a strategy of producing relatively large amounts before the winter started.
    a. If the hydropower producers in autumn 2021 had known what everyone would later find out, they would probably have produced somewhat less in autumn 2021 than they actually did, and correspondingly more during the winter and spring of 2022 (Mo, Wolfgang og Øyn Narvesen 2023). This could in turn have led to two things:
        i. The probability of rationing in the power market in southern Norway during the spring of 2022 would probably have been lower than it actually was. This could have led to somewhat lower prices in spring 2022 than we actually saw.
        ii. However, a more cautious production in autumn 2021 (more water saving) would have resulted in higher prices and thus lower exports than it actually was.
8. The combination of relatively high power generation, especially in southern Norway in autumn 2021, and not particularly high inflow to the reservoirs in the same area until autumn, contributed to relatively low reservoir levels in southern Norway throughout much of 2022. The weather changed in October 2022, resulting in high precipitation, mild weather and relatively low consumption in Norway in the fourth quarter of 2022. If we had instead had a record-high inflow, the price level in southern Norway in 2022 would have been lower. This would have been similar to what we experienced in 2020, where reservoir levels were generally considerably higher than in 2022.

Hydropower, costs and power prices

Hydropower producers are constantly assessing whether reservoir water should be used for production now or saved for future production to meet future power demand. Demand, production of solar and wind energy, imports, exports and future inflow of water are uncertain. In practice, the assessments are made by making price forecasts and planning the allocation of water reservoirs so that hydropower production takes place to the greatest possible extent when prices are highest. Prices are highest when energy supply is scarcest and demand is highest. In this way, producers maximise their income.

It is therefore worthwhile for hydropower producers to save water for the periods when they expect the power to be worth the most, particularly in winter and during periods of high consumption and low production of solar and wind power. If they produce more during periods of low prices, it would contribute to even lower prices during these periods. But this would also mean less water available for power generation when prices are high. Prices during such periods of scarcity would then be even higher. In general, it would be unfortunate for consumers if producers do not maximise production when prices are high. This would result in higher prices overall.

These mechanisms are characteristics embedded in the market design. This contributes to the overall power prices being as low as they can be, based on the market and resource situation. Sometimes we make mistakes, such as in autumn 2021, but not all information is known in advance.

These relationships depend on effective competition. For example, if an operator has market power and can influence prices in an area, this could result in prices being higher than they could and should have been.

See chapter 7 in particular for a more detailed discussion of production adaptation in the hydropower sector.

Towards the autumn of 2022, it became increasingly clear that Europe's energy supply was in a situation no one had ever experienced before. There was great uncertainty about what the future would look like. Industry, other businesses and households across Europe had reduced consumption of both electricity and gas. There was great uncertainty about Europe's ability to get through the winter of 2022/2023 without even more severe gas and power shortages. Late summer 2022 saw the highest forward prices for both power and gas ever observed in Europe. The EU started real discussions on reforming the EU's power market, among other things.

The government appointed the Energy Commission on 11 February 2022, primarily to provide a long-term perspective on fundamental dilemmas in Norwegian energy policy up to 2030 and 2050. The dramatic rise in electricity prices characterised the entire period of the Energy Commission's work. NOU 2023: 3 *More of everything - faster* provides both a good account of price growth through 2021 to the record year 2022 and a clear account of developments before the Energy Act was adopted in 1990. However, the Energy Commission's main focus was not on prices as such, but rather on how Norway can solve its energy challenges in the coming years.

The electricity price crisis caused an unusually large distribution problem[1] that came very suddenly
With the exception of large parts of the power-intensive industry, relatively few electricity customers in Norway have purchased electricity on fixed-price contracts. Whereas foreign consumers generally have fixed-price contracts that are renewed once a year, Norwegian households and businesses generally have contracts where the price follows the price in the spot market hour by hour. Norway is also a significant exporter of oil and gas, but apart from industry and transport, oil and gas prices have little direct impact on Norwegian energy users. However, the indirect impact of gas prices on Norwegian electricity prices is significant.

When electricity prices increased during the summer and autumn of 2021, Norwegian households and businesses were immediately affected. For households, monthly electricity bills rose sharply, both because of the price increase and because consumption normally rises as the temperature drops in the autumn. Most businesses, the public sector and the voluntary sector experienced a similar development. Electricity price The crisis led to a significant distribution problem - electricity customers experienced sometimes dramatic cost increases, while producers saw a sharp increase in income. As power generation is largely publicly owned and is also relatively heavily taxed, revenues for the state and a number of municipalities increased at the same time. An increase in the resource rent tax rate and the introduction of a high price contribution meant a tax increase for producers that generated additional revenue for the state. This provided the basis for a number of temporary support programmes, including the electricity subsidy scheme for households.

More people are questioning the current design of the electricity market
The distribution problem expressed by the extraordinarily high prices has led many to question whether the organisation of the electricity market is appropriate.

[1] In economic theory, distributional effects are used to describe how the economic value of an activity is distributed between producers and consumers. An increase in the price of a product will normally mean increased income for producers and increased costs (or reduced disposable income for other purposes) for consumers.

The current market model is based on the market junction and spot price to control production and consumption, and to incentivise investment. The system has resulted in significantly greater resource efficiency than the old model. It has contributed to very high security of supply and lower average prices than our neighbouring countries. It has worked during a period of good power balance in Norway and neighbouring countries, and where hydropower reservoirs and regulatable fossil energy have been sufficient to provide the necessary regulatory capacity and moderate price fluctuations.

When both the Energy Commission's work and the Electricity Price Committee's mandate call for alternatives or mitigating measures to the current market system, it is partly because the conditions for energy policy are changing. The changes are particularly related to the following factors:

- Energy policy has gone from being a separate policy area with its own energy policy goals, to becoming a tool for climate policy and industrial restructuring. Some refer to this as a paradigm shift.
- The production of renewable energy is an industry in itself with high value creation per employee. Even in 2020, when power prices were unusually low, "Electricity, gas and hot water supply" had higher value creation than all other industries in Norway except the oil and gas industry on the Norwegian continental shelf and the finance and insurance industry.[2] Norway needs industries with high value creation per employee when the oil and gas industry's activity level is reduced.
- Investments in new power generation are governed to varying degrees by expectations of future market prices. Both in Norway and the rest of Europe, the establishment of new production is strongly politically controlled through licences and, in many cases, subsidies or similar. Similarly, political decisions are the reason that nuclear power in Germany is now completely shut down and that some Swedish nuclear power reactors have also been shut down. In Germany, government incentives have contributed to more renewable energy production than the shutdown of nuclear power.
- For many, it appears to be an increasing paradox that the market system is based to such a large extent on marginal costs for production, while the utilisation of an increasing proportion of production capacity is not controlled according to marginal costs. Wind power, river power and power generation from solar cells are not regulated, have very low marginal costs and will (normally) be offered for sale regardless of the market price, at least for any price greater than zero.
    - Many are concerned that the producer surplus will continue to increase until dependence on fossil fuels is greatly reduced, and that electricity customers will not see any benefit from the green shift on their electricity bills.
- In particular, the fact that Norway exports power to neighbouring countries at the same time as we have the highest power prices ever at home has provoked reactions.
- The market's price impulse for rational consumer behaviour is under strong pressure. If prices are too high or vary too much, there are strong demands for measures such as price support or fixed price schemes.
    - In the last two years, more than 400 different measures have been notified in total in the EEA that in one way or another are intended to support end users of energy (electricity and gas)
    - As of 2013, the EU already had a regulatory framework for states that wanted to compensate their industry fully or partially for the effects of the carbon trading system on the price of electricity (CO_2 compensation). The scheme is now being

[2] Source: National accounts, Statistics Norway table 11713. See also About the renewable energy industry (fornybarnorge.no).

transformed into a mechanism for pricing emissions from imported goods (see fact box in chapter 8.10).

We have a different cost and price picture for power production
In many ways, Norway has been perceived as a different country when it comes to energy. Norwegian households primarily use electricity as an energy carrier, and increasingly also for transport as the car fleet is electrified. For heating, we mostly use electricity in Norway. Although the importance of district heating has increased significantly in cities over the past two decades, the share of district heating in Norway is relatively small. Due to its hydroelectric power, Norway has gained a significant position as a host country for power-intensive industry.

Norwegian hydropower, with its large regulatable reservoirs, means that the Norwegian power system will continue to have different characteristics than in other countries. In the future, however, many things will become more similar in terms of production and consumption of electricity. The power market has become a tool in climate policy. Energy use will be shifted away from fossil fuels and towards renewable energy, with significant weather-dependent power generation. The growth in the supply of electrical power will largely come from solar and wind power plants both in Norway and the rest of Europe. For heating purposes, the transition from gas and oil to heat pumps will contribute to somewhat more equal conditions on the demand side of the power market.

It will also have a major impact on how the need for flexibility in the power system is resolved in different countries. Many analyses point to hydrogen based on electrolysis of water as a very relevant option for creating value from power when production is higher than 'normal' consumption. In any case, the extent to which consumption in households, the transport sector, public services, businesses and not least industry change their consumption habits and technology will also be of great importance.

Overall, this indicates that the power systems in Norway and the rest of Europe will become more similar in the years to come, regardless of how capacity and rules for utilising interconnectors develop.

Although many reasons can be identified, there are two factors in particular that are significant for the future cost and price picture for power production:

1. In order to stimulate the transition to renewable energy, the EU established a system of tradable quotas for CO_2 emissions from 2005. As long as the proportion of power generation based on fossil energy carriers remains significant, the market price of emission allowances will have a major impact on the price level for electricity in Europe. After a decade in which the price of CO_2 emissions has been around EUR 5-10/tonne, the price of allowances currently appears to have stabilised at just under EUR 100/tonne. In this context, there is also the question of whether and to what extent the quota system will be supplemented with support for new renewable power generation or similar.
2. The transition to more weather-dependent power generation results in large and frequent changes in power prices (volatility) under the current pricing system. Historically, power prices in Europe have generally been high during the day and low at night, which is linked to the cost of power production based on coal, gas and nuclear power. When consumption is low, only plants with low marginal costs are used, while during the day, when consumption is high, power plants with higher marginal costs are also used. In the future, price differences will largely be driven by whether it is windy or not, and whether it is dark or light. While the latter is relatively easy to predict, wind conditions are highly variable over days, weeks and years. Until our neighbouring countries have found good solutions to deal with the

dependence on solar and wind conditions, there is reason to believe that the situation with large daily variations in power prices will continue.

The establishment and mandate of the Electricity Price Committee must be understood in this context. This is both the reason why the committee was established and the challenges the committee has been working on. In the chapters later in the report, we take a closer look at where we stand today, how we believe the power systems and energy markets will develop in the years to come, what specific needs and opportunities the committee has identified, and finally, we analyse the characteristics of various measures that could potentially contribute to more efficient use of resources and more stable and lower electricity prices.

5 The power market has different players with different roles and tasks

The wholesale market for electric power brings together power producers, electricity suppliers and some industrial companies that buy such large volumes of power that they can benefit from being a player themselves. In the retail market for electricity, households, businesses, sports clubs and anyone else who is not a player in the wholesale market can buy electricity from electricity suppliers. The diagram below illustrates this, but underplays the fact that in the electricity market there are many different tasks that are performed by a number of different actors and actor types. In this chapter, we provide a more detailed overview of who performs which tasks. We also explain the relationship between the different product concepts used in different parts of the electricity market.

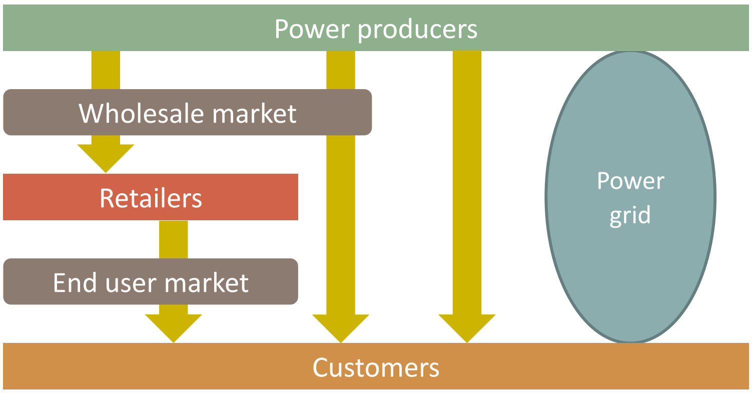


Figure 5- The most important players in the electricity market

Figure 5- shows three of the most important types of players in the electricity market - the customers who buy electricity, the electricity suppliers from whom most of the customers buy, and the power producers who sell electricity to large customers and to electricity suppliers. However, some customers generate electricity themselves - for example, some households with solar panels on their roofs, farms with a small hydroelectric power plant on their own land, and industrial companies with their own power plants - and they have two different roles in the market at the same time.

5.1 Manufacturers

Most of the power generation in Norway takes place in companies owned by Norwegian municipalities or in Statkraft SF, which is owned by the state. Some power generation is also owned by industrial companies established in Norway, which in turn have varied ownership with Norwegian and foreign shareholders. Foreign investors, including pension funds, have invested in Norwegian wind and small-scale power generation over the past 10-15 years. The tasks of the production companies are to develop, build, own, operate, maintain, upgrade and further develop the production facilities. It is their responsibility to ensure that the technology works. Some companies focus more on the development of new plants, for example in solar and wind power, and gradually find new owners for these when the power plants are put into operation.

The producers themselves decide when and how much they want to produce, and at what prices they want to sell. For hydropower plants, this means deciding when to utilise reservoir water. The water authorities (NVE and OED) lay down detailed rules for each individual hydropower plant, which limit the producers' room for manoeuvre (manoeuvring regulations; stipulate the highest and lowest regulated water levels for reservoirs, minimum water flow requirements below dams and power plants, etc.) The large hydropower plants are also subject to requirements for so-called concession power - these are rights for municipalities and county authorities to buy a share of the production at regulated prices.

An important but complicated task for producers is to specify at the start of each hour how much they will produce for the next hour. This is explained below under the heading Balance responsibility.

Within the limits set by the owners' attitude to financial risk, it is the production companies' responsibility to manage the financial risk and, if necessary, price-hedge production.

5.2 Customers

As Figure 5- suggests, producers can sell power in several ways. Most sell their power in the wholesale market, where the buyers are typically electricity suppliers and large industrial companies, but some sell their power as internal deliveries to industrial companies. Another customer group is electricity grid companies, such as Statnett and the companies that operate the electricity distribution grid, which must buy electricity to cover energy losses in the grid.

As with producers, an important task for customers in the wholesale market is to specify at the start of each hour how much they will consume for the next hour. This is explained below under the heading Balance responsibility.

Customers in the retail market do not need to think about balance responsibility - their task is primarily to choose their electricity supplier (and to honour the agreement they have entered into with their chosen supplier).

Many people imagine that power exports take place when foreign operators buy electricity in Norway in the same way as domestic customers, and 'take it home'. In reality, it takes place in a different way, which we explain in chapter 7.

5.3 Power suppliers

Most electricity suppliers in Norway are affiliated with groups that are also involved in power generation and electricity grids, and are therefore indirectly owned by Norwegian municipalities. However, the largest electricity supplier in Norway - Fjordkraft - is owned by the listed Elmera Group ASA.

In simple terms, electricity suppliers are an intermediary between producers and customers. They buy MWh in the wholesale market and sell kWh to their customers.[3] Since they buy in the wholesale market, it is the electricity suppliers who take on the role of balance responsible for most customers in the electricity market.

Depending on the contract between the electricity supplier and the customer, the price the customer pays may vary from hour to hour, or it may be fixed for a shorter or longer period (fixed price agreements). Some electricity suppliers focus specifically on certain customer groups, such as households, 'regular' businesses, customers with electric cars, etc. Different contract types and different segments in the retail market are explained in more detail in chapter 8.

5.4 Power grid company

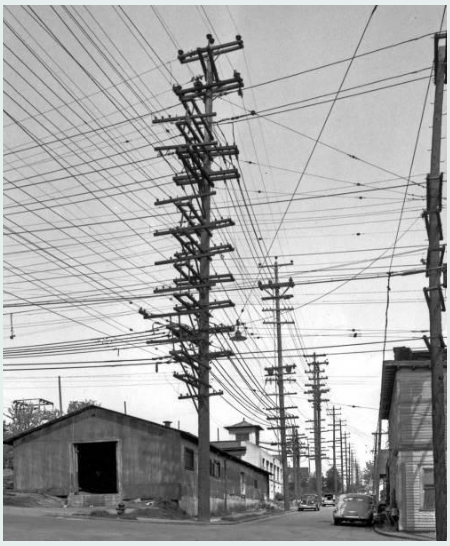
The electricity grid companies are responsible for transporting electrical energy from producers to customers. This involves developing, building, owning, operating, maintaining, upgrading and further developing the electricity grid. They are obliged to connect anyone who wants to be connected to the grid (provided that the customer has legal access to their activity, whether it is the production of electricity or the use of electricity for any purpose), including providing the customer with the

[3] Electrical energy is usually measured in kWh or MWh. 1 MWh (mega-watt-hour) is 1000 kWh. 1 TWh (terra-watt-hour) is 1 billion kWh. Annual consumption in Norway is about 133 TWh, while an average household uses about 16,000 kWh.

capacity they need.[4] The power grid companies' obligation to connect is justified by the fact that these companies have a monopoly on supplying their geographical areas with electricity. Consequently, this activity is also strictly regulated in detail, both in terms of requirements for efficient and safe operation, and in terms of the fees they can charge customers. The reason why the power grid is regulated as a monopoly activity is that the economic characteristics of the power generation and power grid activities are very different.

The power grid - technological and organisational changes

The images below are from Seattle, USA.[5] The image on the left was taken in 1952 and shows the grids of the two competing electricity companies, Seattle City Light and Puget Power. The image on the right was taken about 60 years later. During those 60 years, both the technology and the organisation of the power grid have changed. More customers can be served with fewer lines. We have also learned that the costs of the power grid are lowest when organised in companies that have a monopoly within limited areas.



The images showing Albion are taken from North 36th street, up towards Albion Place North (Dorpat 2013).

Most electricity grid companies in Norway are organised as independent enterprises that only operate electricity grids (corporate separation). Statnett SF owns and is responsible for what we call the transmission grid, i.e. the main transport routes through the country and the connections between Norway and abroad. Statnett has also been designated as the transmission system operator and system operator for the transmission grid, see below under the heading System operator and system responsibility. Just under 100 other grid companies are responsible for the smaller "roads" for transporting electricity, known as regional and local distribution grids.

Although the power grid companies do not sell or buy electricity (other than electricity for grid losses and system operations), and thus have no direct role in the power market, they represent the closest thing we have to a physical meeting place for buyers and sellers. In a way, the power grid plays the same role as the market square where vegetable growers could meet their customers and deliver their goods, back when market trading was commonplace. One can think of the electricity grid as a market that is organised in parallel with the power market, but with completely different conditions

[4] The connection obligation means that the customer is entitled to connection as soon as it is practically possible and operationally sound (for the electricity grid). However, the customer must pay what the connection actually costs and must therefore wait until the grid has sufficient capacity to serve the customer.

[5] Images courtesy of the Seattle Public Library and the Paul Dorpat Collection, respectively.

(monopoly, not competition), cf. Figure 5-. Both power producers and electricity customers are customers in the grid. What the grid companies sell are transport services for electric power, while it is their customers who buy and sell power.

In this sense, the grid companies are facilitators for the power market. This task is primarily the responsibility of Statnett in terms of day-to-day operations, see below under the heading System operator and system responsibility. However, modern communication and sensor technology opens up new opportunities and will over time contribute to some similar tasks for the other grid companies, especially the larger regional companies (Bjørndalen, Løken, et al. 2020).

In terms of long-term development, all grid companies are in principle equally responsible for managing the demand for grid capacity. With the energy transition that we are in the midst of, the big challenge now is whether grid companies are able to establish enough transmission capacity at the same pace as customers and producers develop their projects (NOU 2022: 6).

This question has two dimensions. One is that building the grid is time-consuming for good reasons. The other is linked to the revenue system for electricity grid companies.

- The time aspect is related to the fact that network facilities usually entail significant impacts on nature and that there may be extensive conflicts of interest related to network facilities. It takes time to resolve conflicts of interest in a balanced way. The licence system for grid facilities has been under more or less continuous evaluation and adjustment for at least the last 20 years, most recently with the Power Grid Committee's report (NOU 2022: 6).
- The revenue system for electricity network companies is briefly explained in Chapter 6.9. To put it bluntly, it could be argued that it encourages companies to wait as long as possible to fulfil their connection obligation. One of the challenges is that grid companies that are early to expand grid capacity before demand has actually increased run a certain risk that demand will not increase after all. If this happens, the revenue system will not ensure full cost recovery for this company and at the same time lead to an increase in tariffs for existing customers.
    - This problem applies particularly to small and medium-sized grid companies. Firstly, the owners' ability to withstand reduced return on capital may be limited, and secondly, tariff increases for local customers may create an unfavourable and unattractive cost difference with customers in other grid areas.
    - Companies such as Statnett are less exposed to this. Firstly, Statnett has an owner that can withstand a reduced return on capital, especially if this is a result of a national policy to facilitate the green shift. Secondly, a cost increase for Statnett will not create geographical differences in grid tariffs - Statnett has the same tariff level throughout the country (except for Statnett's energy tariff, which in any case reflects local costs).
    - Distriktsenergi has commissioned a report that suggests two possible solutions to the dilemma that particularly affects the small and medium-sized grid companies; 1) a small adjustment of the system for determining their revenues and 2) a scheme that contributes to the equalisation of grid tariffs across all grid companies (Bjørndal og Bjørndalen 2023). For Statnett, one could have thought along different lines and considered whether the company's purpose should explicitly include responsibility for facilitating the energy transition.

See also chapter 6.9 for an explanation of the electricity network companies' revenues.

5.5 Balance sheet manager

While for many goods we can easily identify the individual unit of the good, we cannot physically label the individual kWh and follow it from power station to customer. The power system can be compared to a bathtub, where producers fill up and consumers take out. We need a system to ensure that producers are paid for the amount they add and that consumers pay for what they take out. In the power market, this system is built around the concept of balance responsibility.

The principle is that the person responsible for the balance sheet must ensure that there is a match (balance) between what you have been told to do and what you have actually done. This can be illustrated with the following example:

- A producer expects to produce 100 MWh in the first hour of the next day, and therefore sells 100 MWh in the spot market that hour. Through the sale, the producer indicates that the delivery will be 100 MWh in that hour.
    - When the hour is finished, it turns out that the output delivered was 98 MWh.
    - In the settlement from the spot market, the producer will be paid for 100 MWh, even though it only delivered 98 MWh.
    - In addition, the producer, in its capacity as balance responsible, receives an invoice for 2 MWh that was the producer's imbalance.
    - The price for imbalance is often different from the spot price. The difference stimulates the producer to make an effort to minimise the difference between the volume sold and the volume delivered.
- An electricity supplier anticipates that customers will consume 100 MWh in the first hour of the next 24 hours and therefore buys 100 MWh in the spot market that hour. Through the purchase, the electricity supplier indicates that the customers' consumption will be 100 MWh in that hour.
    - When the hour is over, it turns out that the consumption was 103 MWh.
    - In the settlement from the spot market, the electricity supplier will receive an invoice for 100 MWh, even if the consumption was higher.
    - In addition, the electricity supplier, in its capacity as balance responsible for its customers, receives an invoice for 3 MWh that was this electricity supplier's imbalance.
    - The price for imbalance is often different from the spot price. This difference encourages electricity suppliers to make an effort to minimise the difference between purchased volume and actual consumption.
- The overall imbalance for the two examples above is that 2+3=5 MWh is missing. For the example to be complete, we must therefore have at least two more players who can provide the missing 5 MWh.
    - The one actor needed is the system operator who organises the procurement of the missing 5 MWh, see below.
    - The second player we need could be a producer who can produce 5 MWh more than planned for the hour in question. Alternatively, it could be a consumer who can consume 5 MWh less than planned for the hour in question (it could be a consumer who is basically self-sufficient in power).
        - In the real market, there are several hundred balance responsible parties in Norway, each of which has some kind of imbalance and which the system operator coordinates to ensure that the market is always in balance.

Balancing responsibility is a fundamental construction in the electricity market, which most customers never come into contact with - unless the construction does not function properly. In the worst case scenario, the consequence could be extensive power outages, which can take a disproportionately long time to repair.

Balance responsibility is formally a role and a task. Most producers, electricity suppliers and large consumers are balance responsible themselves. A producer, an electricity supplier or a consumer can purchase the service from companies that specialise in this. Some companies specialise in managing balance responsibility on behalf of others, such as smaller power producers or producers with relatively small organisations. Balance responsible organisations must enter into a balancing agreement with Statnett.

In addition to balance responsible producers, electricity suppliers and large consumers, the system is dependent on the system operator performing its tasks.

5.6 System operator and system responsibility

Statnett SF is the system operator for the transmission grid in Norway. Statnett has also been designated as the Transmission System Operator in Norway. This entails a number of tasks that are specified in more detail in the Regulations relating to system responsibility in the power system (FOS)[6] . With regard to price formation, there are two main tasks in accordance with FOS that are particularly important:

1. The system operator must ensure that the balance responsibility scheme functions properly. This involves a number of different tasks with accompanying obligations and rights, such as
    a. ensure that the balance responsible parties comply with the balance responsibility system as required by the FOS,
    b. ensure sufficient resources to cover any imbalances that arise (cf. the 5 MWh in the example above), and
    c. ensure that the money flows are correct (settlement, in Norway via eSett Oy, a company owned by Statnett and their Nordic 'colleagues', Svenska kraftnät, Energinet and Fingrid).
2. The TSO must manage bottlenecks in the transmission grid and regional distribution grid, and ensure that as much of the transmission capacity as possible is made available to the market. This work can be described as a multi-phase process:
    a. **The planning phase** has three main elements:
        i. The power grid is not strong enough to ensure that all producers and consumers throughout Norway receive the same price. An equal price would result in congestion in the grid due to regional imbalances between consumption and production. To avoid overloading the grid, Norway is currently divided into five bidding zones, NO1 to NO5. Bidding zones are thus a tool for Statnett to take into account the physical limitations in the power system. How a country defines bidding zones is of great importance for price formation in neighbouring countries as well. The process is carefully regulated through a European regulation on capacity allocation and congestion management (CACM).[7] It takes years to change bidding zones. See chapter 7 on how price formation depends on bidding zones.
        ii. In order to carry out planned maintenance and emergency repairs, it may be necessary to disconnect grid facilities and/or power plants. Such shutdowns

[6] Regulation on system responsibility in the power system, FOR-2002-05-07-448.
[7] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

must be coordinated. Planning usually starts up to a year before the actual day of operation.

    iii. Two days before the operating day, Statnett, together with its Nordic colleagues, decides how much of the transmission capacity between bidding areas can be made available to the market. Between some bidding areas there is only a single connection, while between other bidding areas there may be a number of connections. For all such border crossings, both between countries and between bidding zones within a country, the system operators have jointly decided how much can normally be transferred between the different bidding zones. The daily task is to decide whether there is anything that indicates a lower capacity limit for the market for the day that starts two days later. In the Nordic region, this is done through Nordic RCC A/S in Copenhagen, a company owned by Statnett and their Nordic 'colleagues', Svenska kraftnät, Energinet and Fingrid). RCC is an acronym for Regional Coordination Centre. The regulatory framework for determining transmission capacity is a central part of CACM. Planning then continues towards the operating day with the spot price being set, the participants fine-tune their plans and ensure that they have a balance between planned and sold production or purchased consumption.

b. **The operational phase is** the time when production and consumption actually take place - the operational phase is 'now'. During the operational phase, the system operators must monitor that everything is working properly and implement measures when faults occur or there is a deviation between what is planned and what happens for other reasons. The aim is to ensure that operational reliability is not jeopardised. More and more of this activity is being automated.
c. **The settlement phase** can be described as the hour of reckoning. The players must be paid or invoiced in accordance with what has been agreed and what has been realised.

In practice, the tasks described in 1b and 2b take place in parallel, and largely as an integrated and standardised process. The tasks described in 1c and 2c are integrated into a common settlement process.

The link between the activities of the transmission system operator and the actual power market is so strong that the precursor to today's most important marketplace in the Nordic region (Nord Pool, see below under the heading Marketplaces) was called Statnett Marked, and was a wholly owned subsidiary of Statnett.

The grid companies that own and operate regional and local distribution grids are system operators for their grids and grid facilities, with some exceptions. In Norway, the system operator (Statnett) is also responsible for congestion management in the regional distribution grid. This means that all outage planning must be coordinated with Statnett and that Statnett has the right and obligation to intervene in operations in the regional distribution grid if necessary.

Capacity in the electricity grid, flow-based market coupling and sum restrictions
The electricity grid is a meshed network. You can think of all power plants and consumers as points connected to each other via overhead lines, underground cables or submarine cables. Some of the points in the network are transformer stations that connect networks with different voltages. Other points are so-called switch fields, which can be compared to road junctions - here several lines meet and 'traffic' is distributed on the lines - the roads - in and out of the junction.

A bidding zone is a collection of such points. Most bidding zones are connected to the neighbouring zone by several lines in an AC grid. Norway (NO2) and Germany are 'only' connected by one DC cable, but are also indirectly connected via Jutland (DK1).

To ensure that power trading does not lead to excessive power flow in individual components and breakdowns in the power system, trading capacities must be specified that limit trading to what the power grid can withstand. When sending electrical power from bidding zone A to bidding zone B in an AC grid, the power will follow the path of least resistance, according to Ohm's and Kirchoff's laws of physics. The physical flow of power will thus be spread out on all lines in the network between A and B to minimise electrical resistance. How much trade can be allowed between A and B therefore depends on how production and consumption is distributed between all the other bidding areas in the system.

Traditionally, the system operators for the transmission grid have calculated a net **transfer** capacity (**NTC, Net Transfer Capacity**) between all bidding areas. The result could be that the capacity between A and B was set at 1000 MW, between B and C at 2000 MW, and so on. The disadvantage of this method is that the capacity calculation must take into account combinations of distribution of production and consumption between each bidding zone, which together result in the transfer capacity between A and B, B and C, and so on, being very small. There can often be a large difference between the worst case and the best case, so that in practice, power trading is unable to utilise the grid connections particularly well. Poor utilisation means that the flow both in each line individually and overall between bidding zones is (significantly) less than it could have been.

System operators in Europe have therefore developed a more advanced way of telling the market and the market algorithm about the capacity in the network. This is called **flow-based market coupling (FB)**. The power exchange then has access to a simplified grid model where all the relationships between trading and physical flow are specified. In this way, it is possible to tell more about what the capacity for power flow between A and B depends on. In the market clearance, a larger proportion of the installed capacity can therefore be utilised for power trading without the resulting power flow threatening the grid's physical tolerance limit.

Flow-based market coupling has not yet been implemented in the Nordic region. In the meantime, a **sum restriction** has been introduced between bidding zones NO1, DK1 and SE3. We can see this as a kind of simplified and geographically limited variant of flow-based market coupling. The restriction specifies a maximum limit for simultaneous trading between NO1-SE3 and DK1-SE3. This means that trading between NO1 and SE3 can be increased if there is less trading between DK1 and SE3 and vice versa. It is therefore the value of the trades, expressed through the price differences, that determines how much trade is accepted at each border in the market coupling. Without sum restriction and in anticipation of flow-based market coupling, the capacity for trading between these bidding zones would be less than it is now.

5.7 Marketplaces

Most of us think of the electricity market as a single market. In reality, this market consists of several sub-markets, with different tasks, conditions, regulations, market mechanisms and products. Thus, there are also a number of different marketplaces. The interaction and 'division of labour' between different types of marketplaces is explained below.

An important distinction between different marketplaces is between those that are regulated by special rules and those that are more unorganised. Another important distinction is shown in Figure 5- - The wholesale market and the retail market are different and have different marketplaces.

5.7.1 The wholesale market has both organised and informal marketplaces

In the wholesale market, **power exchanges are** the best-known marketplaces. They facilitate trading in three different sub-markets with different time horizons:

- The most important and well-known time horizon is what we call the **spot market** (Single Day-Ahead market Coupling (SDAC) in EU legislation). There is an auction every day at 12:00. Here, the so-called spot price is set, which in practice is a price for each hour of the following day for each bidding zone within almost the entire EEA.
- At 15:00, what we call the **intraday market** or Single Intra Day market Coupling (SIDC) opens. Here, participants can trade further for the individual hour for the same operating day, for example if it appears that wind power production for the next day will be lower than expected. In Norway, the intraday market closes 60 minutes before the individual operating hour starts.
- **The forward market is** used for trading in long-term contracts, for example for the next month, the next calendar year or even further into the future. The forward market covers the part of the need for long-term contracts that can be realised via a power exchange, see below.

Figure 5- 2 Countries participating in SDAC (Source: ENTSO-E)

The activities of the power exchanges are regulated by law and regulations, and largely with the same or similar regulations throughout the EEA. Most power exchanges active in Europe and Norway serve multiple sub-markets and multiple countries. In Norway, these are the most important organised marketplaces:

- **Nord Pool** operates a marketplace for the spot market and intraday market in Scandinavia, Finland, the Baltic States, Poland, the UK and a number of countries on the continent. Nord Pool is 66 per cent owned by the European exchange company Euronext and 34 per cent jointly owned by Statnett, Svenska kraftnät and EPSO-G (a state-owned company in Lithuania, which owns the transmission grid in Lithuania).

- Among other things, **Nasdaq** operates a marketplace for the Nordic power futures market. Nasdaq is an American listed company that offers financial services mainly in the US and Europe. The company owns and operates a number of stock exchanges, including in Stockholm, Copenhagen and Helsinki, as well as several commodity exchanges, including for the power market elsewhere in Europe, for fish, for the gas market and for the European market for greenhouse gas emission allowances.
- Before the summer of 2023, it was announced that **EEX** - European Energy Exchange - will take over Nasdaq's activities in the Nordic power futures market. EEX operates a marketplace for the forward market, spot market and intraday market across large parts of the EEA. Through its subsidiary EPEX, EEX offers its members to trade in the spot market and intraday market in Norway and the Nordic region.

A key element in the regulation of the power exchanges, particularly for the spot market and the intraday market, is that it is up to the individual country to decide whether a marketplace should have a monopoly on the relevant activity or not. Most countries in the EEA area allow for competition between market centres. This also applies in Norway. In practice, however, the vast majority of trading in the spot market and intraday market in the Nordic region has been conducted via Nord Pool.

In addition to the organised marketplaces, there are two main types of unregulated sub-markets in the wholesale market. Unregulated means that there is little specific regulation for the activities, but they are of course subject to general legislation in the country where the activity takes place.

- Trading in standardised contracts. These are traded on an exchange or what is known as OTC (Over The Counter), where a broker acts as a middleman or intermediary. If exchanges such as Nasdaq are efficient and have good liquidity (many buyers and sellers who are constantly trading), participants will generally favour exchanges. If liquidity is weak, participants in need of price hedging will typically prefer to ask a broker to spend some time and find counterparties. In the Nordic region, OTC trading is still common for forward contracts that hedge the price in a specific bidding zone. OTC trading represents both competition for and a supplement to power exchanges such as Nasdaq and EEX, and is considered part of the futures market.
- Direct trade between buyer and seller. Today, this is often referred to as a PPA (Power Purchase Agreement) or bilateral contracts. The main differences between bilateral contracts and standardised contracts are that the contract terms can be tailored and that the duration is longer than the time horizon of OTC contracts. Such contracts are an important supplement to the forward market, and for the parties, activity in the forward market is often a prerequisite for entering into this type of contract. Although the agreements are entered into directly between buyer and seller, the parties often use the services of brokers and financial or legal advisers.

Finally, the transmission system operator's platforms for purchasing various services, often referred to as reserves, regulating power or balancing power, are important marketplaces for participants in the wholesale market. This goes back to the 5 MWh in the example above. Statnett and the other system operators for the transmission grid in the Nordic region use various platforms, which in practice are auction schemes for purchasing the services they need to ensure instantaneous balance in the power system and to ensure that bottlenecks are handled efficiently. **Reserve markets**, balancing markets or real-time markets are often used as a collective term for these markets, even though the agreements are sometimes concluded for up to a week. Figure 6- shows an overview of the relationship between the various markets.

5.7.2 The retail market does not have marketplaces in the same way

The retail market does not have marketplaces in the same way as the wholesale market. The closest thing to marketplaces are online services for comparing offers from different suppliers. The Consumer Council operates the portal www.strømpris.no. In addition, there are some private initiatives, such as www.elskling.no and www.bytt.no. A broader review of the organisation of the retail market can be found in chapter 8.

5.8 Authorities

An overview of the players in the electricity market must also show the various government bodies involved in the sector. The authorities' tasks range from setting the framework for the market, setting requirements and securing rights for the players, creating detailed regulations where necessary, processing complaints and supervising the players.

- The legal framework for the key elements of the electricity market is administered by the Ministry of Petroleum and Energy, which is responsible for the licences required to build power plants and grid facilities, the framework for the wholesale market and for regulating the activities of the electricity grid companies.
- Hydropower is exposed to special tax rules that are administered by the Ministry of Finance. The Ministry of Finance also has overall responsibility for the regulation of financial power exchanges and organised forward trading in power.
- The Ministry of Children and Families is responsible for consumer affairs and has therefore also been involved in consumer rights, etc.
- The Norwegian Water Resources and Energy Directorate (NVE) reports to the Ministry of Petroleum and Energy and is responsible for (among other things) managing the country's water and energy resources. NVE handles all licence issues for power production and grids, including those where the final decision is made by the MPE or the King in Council.
- The Norwegian Energy Regulatory Authority (RME) has been appointed by the MPE as the regulatory authority pursuant to Section 2-3 of the Energy Act and Section 4 of the Natural Gas Act to perform the tasks of an independent regulatory authority. RME is organised as a separate unit within NVE. RME ensures that operators comply with the regulations that ensure equal terms of competition in the electricity market and an efficiently operated electricity grid. RME regulates the activities and revenues of the electricity grid companies. RME also regulates the physical power markets (spot market, intraday market and reserve markets).
    - RME is a member of the Council of European Energy Regulators (CEER), which is a co-operation body for RME and similar bodies in other European countries. However, CEER is not an authority.
- The European Union Agency for the Cooperation of Energy Regulators (ACER) was established in March 2011 as an independent body to promote market integration in Europe and complete the internal market for electricity and gas.
    - ACER's Board of Regulators (BoR) has overall responsibility for ACER's regulatory decisions. RME is a member of the BoR, but without voting rights. The BoR cannot be instructed by anyone, including the Member States, the European Commission or other public or private bodies.
    - ACER's Board of Appeal (BoA) handles appeals against decisions made by ACER. The BoA's decisions can be appealed to the Court of Justice of the European Communities.

- The EFTA Surveillance Authority (ESA) monitors the extent to which Iceland, Liechtenstein and Norway implement and comply with EU legislation so that these three countries can participate in Europe's internal market.
- The Consumer Authority supervises marketing and contract terms, enforces consumer protection legislation and mediates in conflicts between consumers and businesses. Electricity is one of the areas for which the Consumer Authority is responsible.
- In the power market, the Financial Supervisory Authority of Norway supervises power exchanges that offer futures trading (Nasdaq) and central counterparties (Nasdaq Clearing). The FSA also monitors compliance with Norwegian rules that implement the key EU/EEA legislation European Market Infrastructure Regulation (EMIR) and Markets in Financial Instruments Directive (MiFID II) in Norway.
- The Norwegian Competition Authority enforces the Competition Act, which prohibits anti-competitive co-operation, abuse of a dominant position and mergers and acquisitions that restrict competition. The Norwegian Competition Authority does not have a specific mandate related to the electricity market, but deals with cases in this market in the same way as all other markets, provided that the conditions are met. The Norwegian Competition Authority has also from time to time assessed competition in the wholesale market.

6 One market with many sub-markets and even more prices

In chapter 5 we have briefly described that we have different sub-markets (spot market, intraday market, reserve market and long-term market). All of these are part of what we collectively refer to as the wholesale market for electricity. The retail market is explained in chapter 8. We have also explained that power delivered to the grid follows the laws of physics and flows in the path of least resistance. It is therefore not possible to separate the different producers' deliveries from each other. In this chapter, we continue to explain price formation in the various sub-markets and more about the purpose of the various sub-markets. The presentation is based on chapter 5.

As we know, power prices vary in both time and space. To make the explanations below as simple as possible, we will wait to discuss the spatial dimension - power exchange with foreign countries, or between bidding areas in Norway - until chapter 7. To get a complete picture of how power prices are formed, you should read chapter 5, 6 and 7 in context.

6.1 The different sub-markets have different purposes

Figure 6- provides an overview of the different time horizons in the wholesale market. The figure is read from the right and is based on a specific hour of operation. As an example, we can consider the ninth hour, i.e. from 08:00:00 to 08:59:59, Thursday 12 October 2023. [8]

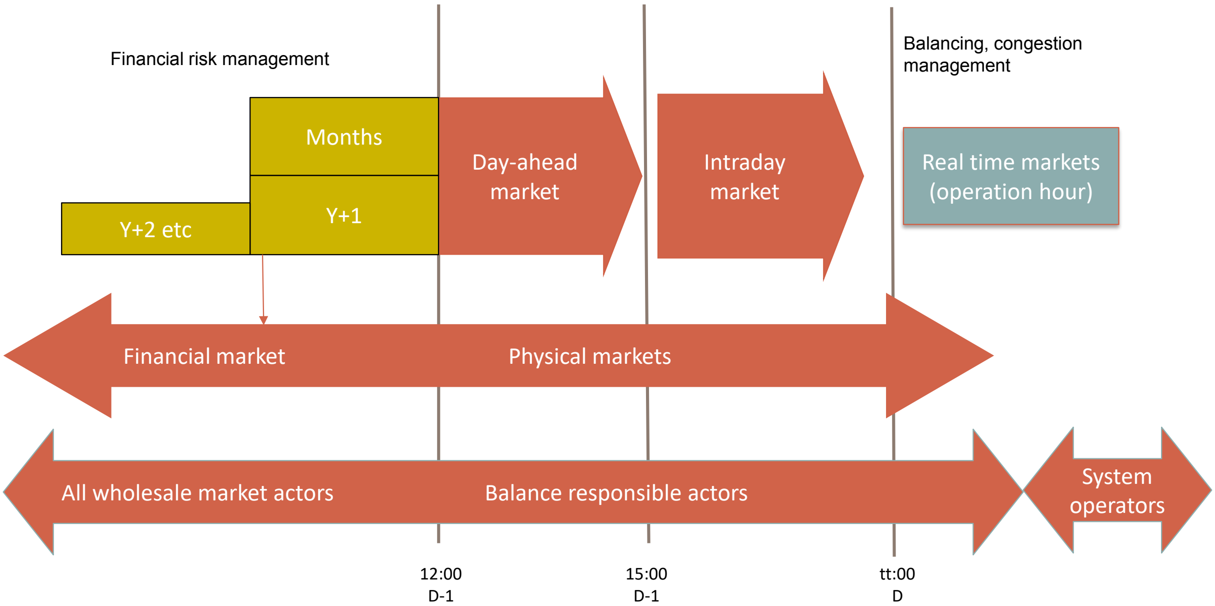


Figure 6- Different markets for trading at different times and for different purposes

6.1.1 Reserve markets are important for operational reliability

During the operating hours, Statnett, in its capacity as system manager and system operator for the transmission grid, needs up and down regulation, partly to ensure that the frequency in the power grid remains at 50 Hz (this is called balancing), and partly to ensure that capacity limits for the components in the power grid[9] are not exceeded (this is called congestion management).

[8] In the European wholesale market, the concept of the operating hour is being replaced by 15-minute periods. Gradually, planning and trading in the wholesale market will increasingly focus on the individual quarter-hour. In this presentation, we ignore this - the principles will remain the same, and for the most important markets - the spot market and the long-term market - the change has little practical significance for price formation.

[9] We are referring here to the physical building blocks of the power grid, such as wires and cables, switches, transformers and capacitors.

Statnett uses reserve markets for this purpose, where Statnett is the buyer and balance responsible parties are sellers competing for supply. Upward regulation means increased production or reduced consumption compared with what was planned when the hour started. Downward regulation means reduced production or increased consumption compared with the plan. Some of the agreements used in the reserve markets are entered into days or weeks in advance - this is explained in more detail in chapter 6.6 below.

6.1.2 The spot market and intraday market are used for physical planning

Prior to the operating hour, both market participants and Statnett have made plans for the hour. No later than 45 minutes before each operating hour, i.e. at 07:15:00 in the example in Figure 6-, Statnett must be notified by the balance responsible parties of their plans. Pursuant to section 8 of FOS (Regulations relating to system responsibility in the power system[10]), the market participants must then *ensure a planned balance between their obligations and rights, including their own production.* Balance responsible parties (see chapter 5.5) for consumption must ensure that they have purchased or have their own production corresponding to expected consumption; balance responsible parties for production must ensure that they have sold or have their own consumption corresponding to expected or desired production. The contracts included in this planning may be traded via a marketplace, or they may be bilateral agreements entered into directly between buyer and seller.

In practice, most of the operators' planning is clarified in the spot market (see chapter 5.7.1). By 12:00 the day before, balance responsible parties submit sell bids for what they want to sell and buy bids for what they want to buy for the next 24 hours. If something has been sold or bought via a (long-term) physical agreement at an earlier time, the BRP(s) must explicitly state how these agreements are to be utilised for the hour in question.

Intraday market (see chapter 5.7.1) is first and foremost a market for the participants to adjust their balance. In the time between the end of the spot market at 12:00 and the operating hour, the participants may receive new information, for example in the form of better forecasts for wind power production or expected consumption. If new information indicates that the planned balance no longer holds, the market participants in question will consider whether they can buy or sell the necessary change in the intraday market.

When Statnett receives information, partly from the players with bilateral agreements and partly from the power exchanges about agreements entered into in the spot market and the intraday market, they must ensure that the plans can be physically realised. Specifically, Statnett checks that no bottlenecks are under excessive pressure and that changes from one hour to the next do not jeopardise the stability of the system. Some of these checks are carried out immediately after the spot market is cleared the day before the operating hour.

6.1.3 Long-term markets are used for financial risk management

Long-term agreements (see chapter 5.7.1) have the main purpose of contributing to financial planning and placing financial risk with those who have the lowest cost of bearing such risk. The physical purchase or sale of power can always be done in the spot market or the intraday market. Because prices can vary quite widely, the financial outcome of trading everything in the spot market can be quite different from what the participants had prepared for. Long-term contracts can reduce such uncertainty.

If the purpose was only to redistribute risk, it would not be a problem if information about prices in long-term agreements was not known to anyone other than the parties to the agreement. However,

[10] Regulations on system responsibility in the power system - Lovdata

the parties are concerned that price hedging does not cost more than is strictly necessary (see chapter 6.7.1) and many (others) benefit from information about the prices in long-term agreements. A stock exchange can fulfil these needs in two ways.

Exchanges are marketplaces that attract more than those who want to hedge physical positions, such as expected power production or expected power consumption. Others who are attracted are players who see a business opportunity in meeting these needs. The most efficient stock exchange markets are characterised by the presence of many such speculators with a high level of activity. The more activity, the easier it is for players with physical hedging needs to find counterparties at the most favourable price possible.

A stock exchange can also create openness (transparency) about prices by publishing statistics showing how much is traded and at what prices. In the academic literature, price discovery is considered an important task for stock exchanges. Price discovery also improves the more activity there is on the exchange. The better the price discovery, the better the opportunities for those who want contracts that are better adapted to their own needs than standardised futures contracts, such as PPAs or ordinary fixed price agreements. PPAs or other forms of direct contracts between power producers and electricity customers will be more expensive for electricity customers without a liquid forward market.

The difference between a physical and a financial agreement is primarily of a purely administrative nature (with exceptions as explained below).

- A financial agreement is solely an agreement between the buyer, the seller and, if applicable, the marketplace and the clearing bank (see chapter 6.1.4) used by the marketplace. No one else needs to know about the agreement. If the buyer or seller in a financial agreement also wants a physical delivery, this must be bought or sold in the spot market (or intraday market).
- For a physical agreement, on the other hand, the system operator (the system operator responsible for settlement in the power system) must receive information from each party to the agreement for each operating hour about the volume that the individual balance responsible party has bought or sold. If the operator forgets to provide this information, the operator will have an imbalance (deviation between production or consumption and the agreements entered into) for which it must pay.

It follows that the cash flows are slightly different for financial and physical contracts. This is easiest to explain with a small example: Assume that A has purchased 1 MWh from B for NOK 670/MWh for delivery on 12 October 2023 from 08:00 to 09:00. We assume that both A and B are balance responsible parties and physically located in the same bidding zone.

- Physical agreement
  A states to Statnett that they will receive 1 MWh, B states that they will supply 1 MWh. B delivers power as agreed and sends an invoice to A for NOK 670.
- Financial agreement
  The cash flow depends on the spot price, so we have three possible outcomes - that the spot price is lower than, equal to or higher than NOK 670/MWh.
    - For example, the spot price is NOK 430/MWh: B sends an invoice for NOK 240 to A. The amount appears as the agreed price 670 minus the actual spot price 430; 670-430=240.
      If A is actually going to use 1 MWh, he buys from the spot market and must pay NOK

430 there. Together with the NOK 240 invoiced by B, the total cost is NOK 670/MWh for this hour. The same calculation for B shows a total income of NOK 670 for B.

- For example, the spot price is NOK 913/MWh: B sends a credit note (and money) for NOK 243; 913-670=243.
  If A is actually going to use 1 MWh, he buys from the spot market and must pay NOK 913 there. Together with the NOK 243 received from B, the total cost is NOK 670/MWh for this hour. The same calculation for B shows a total income of NOK 670 for B.
- The spot price is exactly NOK 670/MWh, and there is no exchange of money between A and B for this hour.

As long as the participants report their physical agreements correctly and the spot market is cleared as normal, the only difference between a physical and a financial agreement will be more administrative work and a greater risk of administrative errors with physical agreements.

However, if the spot market is not cleared in the usual way, buyers and sellers will not receive the full volume they have assumed (see chapter 6.4.2 on lack of clearance). Those who have physical agreements will still be entitled to full delivery in accordance with their agreements and will not be affected by any curtailment in the spot market.

Financial trading mainly takes place on the NASDAQ Oslo ASA stock exchange. Market participants can hedge the price of buying and selling future physical electricity for up to 10 years into the future. Available contracts have different durations: weeks, months, quarters and years, divided into different product types, either forward, futures or option contracts, but also EPAD.[11] Liquidity in the next few years is higher and decreases beyond the 10-year period, but prices in the market 10 years ahead are available. Financial trading in the power market includes all trading in financial instruments for both risk management and speculation.

In June 2023, EEX and NASDAQ Commodities announced their intention to transfer NASDAQ's European power market operations to EEX. The merger is subject to approval by the European Commission's Competition Directorate. The agreement involves the only two exchanges for trading and clearing of Nordic contracts.

Over the past ten years, liquidity (turnover) in the futures market has fallen more or less continuously. The negative trend started when US players withdrew from Europe in the wake of the financial crisis in 2008. To reduce the risk of future financial crises, Europe gradually introduced a requirement that collateral for clearing listed futures contracts be provided in the form of cash or listed securities. Bank guarantees were no longer accepted. After this, liquidity fell. The price shock from 2021 has further weakened liquidity.

6.1.4 Clearing - financial agreements often have a central counterparty

Forward contracts traded on a power exchange are reported for clearing at a clearing house, which then acts as a central counterparty (CCP). A central counterparty is an intermediary that in a certain

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[11] **Futures** and **forwards** are contracts or agreements on a financial settlement for an agreed amount of electricity for a specific period of time and at an agreed price. For futures, the trade is settled both during the trading period and during the delivery period. With forward contracts, settlement only takes place during the delivery period.
Options give a right, but not an obligation, to buy or sell a futures contract in the future at a specific price. NASDAQ Oslo ASA only trades European options, which are options that can only be exercised on a specified date.
EPAD (Electricity Price Area Differentials) are futures contracts used to hedge the price difference between the system price in the Nordic region and the area price in the relevant bidding zone.

sense can be perceived as the buyer's seller and the seller's buyer. The participants on the power exchange can be direct members of the CCP (Direct Clearing Member) or 'clear' via a Clearing Bank (General Clearing Member, GCM), which then stands between the customer and the CCP.

The purpose of clearing is to reduce counterparty risk for both parties to the contract. If A or B in the example above goes bankrupt between the time the contract is signed and the time of delivery, there is a high risk that one of them will lose money - depending on who goes bankrupt and whether the spot price ends up above or below the contract price.

CCPs manage counterparty risk through what are known as margin requirements. We can explain this by continuing the example above. First, a margin payment is calculated on the trading day - this is linked to the risk of one of the parties not being able to settle when the contract is delivered and is in practice determined as a proportion of the contract sum (x per cent of NOK 670/MWh multiplied by 1 MWh). This is called the Initial Margin.

If the market price of the futures contract changes in the period after conclusion but before delivery, the party that experiences an unfavourable change must pay an amount to the CCP corresponding to the economic but unrealised loss. This is called Variation Margin. Assume that the next day the market price for a corresponding contract ends at NOK 673/MWh. A, as the buyer, has then earned NOK 3 (NOK 3/MWh multiplied by 1 MWh), while the seller B has made a corresponding loss. If B now pays NOK 3 to the CCP, the latter has ensured that the price change itself does not change the CCP's ability to fulfil its obligations to the buyer - even though the change may cause problems for B. The next day, the market price of the corresponding contract may fall to NOK 665/MWh. The seller then gets back its NOK 3, while the buyer must pay NOK 5. [12]

NASDAQ Clearing AB is responsible for the actual clearing and settlement of trading contracts entered into on the NASDAQ Oslo ASA marketplace. The CCPs also offer clearing of bilateral contracts entered into outside the marketplace. NASDAQ Clearing is subject to the Swedish Financial Supervisory Authority (Finansinspektionen), as its head office is in Stockholm.

6.1.5 Margin requirements become large amounts when prices change a lot

In the simple example in chapter 6.1.3 and 6.1.4 the total energy volume we reviewed was 1 MWh. In practice, the volumes are significantly larger. An electricity producer with a normal annual production of 1 TWh may at any given time have sold a large proportion of the expected production for the next year, a smaller proportion of the expected production for the following year and also some of the expected production for the third year. If we assume that total sales in the forward market are approximately equal to expected annual production, the effect of a modest price increase of NOK 3/MWh is a margin requirement of NOK 3 million (for a hedging volume of 1 TWh). If Norwegian producers have hedged a total of 100 TWh in the forward market, they must pay a total of NOK 300 million to the clearing bank if prices rise by NOK 3/MWh. If prices rise by around NOK 3/MWh every day for a week or two, or if prices rise more from one day to the next, the margin requirements increase by billions, not millions.

Margin requirements are due for payment on the same day or the day after the price changes are registered. While in the Nordic power market it was originally possible to use bank guarantees to meet the margin requirements, the rules in Europe were harmonised in the wake of the financial crisis in 2008. Since then, CCPs are not allowed to accept anything other than pure cash deposits or listed securities.

[12] The description applies to the clearing of a futures contract. For a forward contract, the procedures are somewhat different.

In the event of major price changes in the market, participants must therefore reduce their forward hedging and borrow significant amounts from their banks. This can in turn lead to the banks having to borrow money from central banks in Europe. In the worst case scenario, the banks' risk exposure to the power sector could be greater than the regulation of the banks allows for. When the governments of Sweden and Switzerland, for example, decided in 2022 that their central banks would guarantee the power companies' loans to banks in Sweden and Switzerland, the need for cash was linked to the margin requirements.

When prices fall, buyers will be faced with corresponding margin requirements. An electricity supplier or other energy company that sells PPAs or other types of fixed price agreements to its customers, and that uses the forward market to manage the risk such agreements entail for the supplier, must take such costs into account when calculating the prices to end users. See also chapter 6.7.2.

6.2 Bidding in the spot market is based on the players' alternatives

Every morning throughout the year, power producers, electricity suppliers and major end users start a process that ends with them submitting their bids for buying or selling in the spot market before 12:00 noon. A bid indicates how much the player wants to buy or sell in a given hour at different prices. The bids can be different from one hour to the next. If the market participants so wish, they can link bids for several hours so that the bid for hour t+1 depends on whether the bid for hour t is accepted. Each bid can be illustrated as a curve in a price/quantity diagram - buy bids can be understood as demand curves and sell bids correspond to supply curves. Figuratively speaking, the spot price is calculated as the combination of price and quantity that creates a balance between aggregated buy and sell bids, see Figure 6-The figure shows how both supply and demand differ at different times.

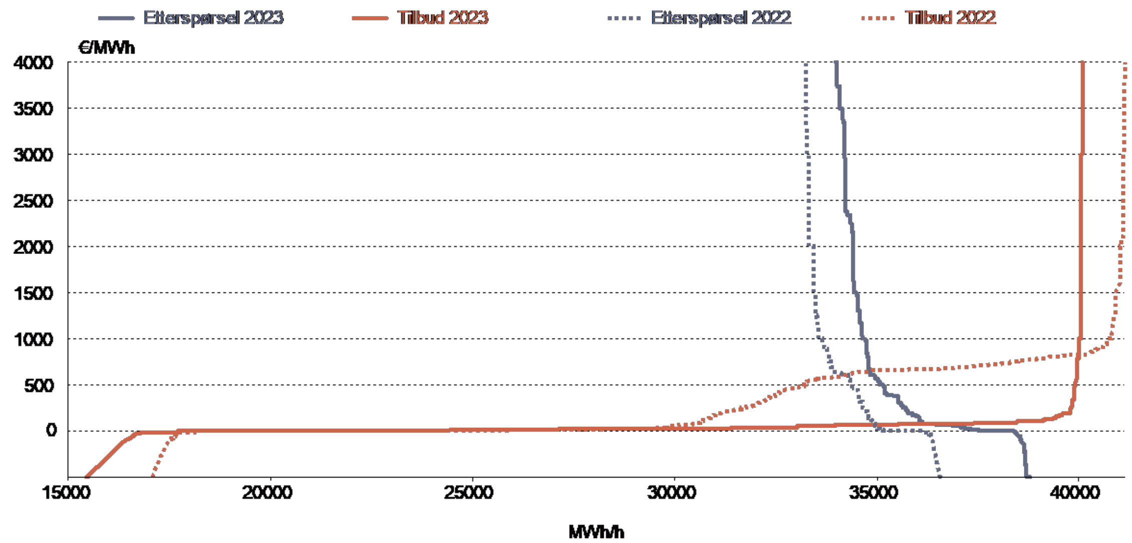

Figure 6- Aggregated bidding curves for the Nordic region (Nord Pool only), hour 9, 31 August 2022 and 2023 (Produced by Statkraft with data from Nord Pool)

Behind all bids is an assessment by each bidder of what the alternatives to buying or selling in the spot market entail from an economic perspective.

- For electricity suppliers who buy on behalf of households, office buildings and other 'ordinary' businesses, it is common to base their calculations on the expected outdoor temperature for the morning day, the day of the week and whether there are any special events that indicate unusual consumption tomorrow. If the supplier has experience that consumption will be somewhat lower at very high prices, it will take this into account. This means that the purchase offer will only to a small extent depend on the price. If the electricity supplier believes that customers will use a total of 100 MWh regardless of the price, there is no option to buy less if the price is high and more if the price is low. The bidding curve then simply becomes a vertical line in the diagram in Figure 6-.

- For larger and typically industrial customers, the activity for which they may use power may become unprofitable if the price exceeds a certain threshold. For others, the activity may become particularly attractive if the price falls below another threshold. Specifically, this may mean that the bid involves a relatively large volume at low prices and perhaps a significantly lower volume at high prices.
    - If a share of the expected consumption has been purchased previously on a physical bilateral agreement, the purchase offer will normally be obtained by subtracting the contract volume from the expected consumption. If the bilateral purchase is greater than the planned consumption, it may be possible to sell the excess if the price is high enough.
    - Whether something has been purchased previously on a financial forward contract (long-term agreement) does not necessarily affect the purchase from the spot market. The example above shows that the buyer can (partially) finance high consumption even at high prices with the payment linked to the financial agreement. However, this is not the same as consumption 'despite' high prices being the most financially attractive for the customer in question - it depends on the purpose of the power consumption and the financial consequences of reducing consumption.
- For power producers that are based on wind, solar or river power with no real alternatives to producing based on wind, solar or river flow, it is common to offer the expected production regardless of a price greater than (almost) zero. This corresponds to a vertical bidding curve for all prices greater than (almost) zero.
    - In some countries, support programmes for wind power or solar energy are designed in such a way that the support is dependent on current production - even if power prices are negative. If the subsidy is greater than what the producer has to pay to deliver the electricity to the grid, the sales bid will typically reflect this. Dutch subsidy programmes for private solar cell systems are a significant reason why we have had periods of negative power prices in parts of Norway in the summer of 2023.
- For power generation based on a fuel (gas, coal, oil, biofuel, waste, uranium) or water in reservoirs, sales bids are normally based on the assumption that the fuel or water can alternatively be used at a later date. This means that use 'now' entails a cost that corresponds to the cost of obtaining a new quantity of the same fuel or the value the water can create through later use.
    - If the power producer must have allowances for greenhouse gas emissions, the cost of this, or the market value of the allowances, must be added, even if the allowances are received free of charge, if the allowances are tradable.
    - Fuel-based power generation is often accompanied by the simultaneous production of heat for district heating plants. Depending on the obligations to supply heat, the desired power sales may be higher than the ratio between the power price and the cost of fuels and emission allowances alone would indicate.
    - For hydropower plants with reservoirs, requirements for minimum water flow in the watercourse can have a similar effect, and lead to higher production than the ratio between the power price and the value of the water alone would indicate.
    - If the producer has already sold a volume under a physical bilateral agreement, the sales offer will normally be obtained by subtracting the contract volume from the

planned production. If the contracts cover a larger volume than the producer wishes to produce himself, he must buy the missing volume in the spot market.
    - Any forward contracts need not have any impact on planned production and sales in the spot market. Rational producers will normally disregard the cash flow from price hedging agreements.
- For all power generation, it would also be rational to take into account the influence of the production decision on maintenance and wear and tear costs, as well as the costs of starting and stopping the power plant. Just as it is common to think that every kilometre driven in a car costs more than the fuel consumption - for insurance, service and loss of value - most power producers take similar considerations into account when planning tomorrow's production.
    - Starting up a gas or coal-fired power plant can easily cost a few hundred thousand kroner each time. Thus, it is not obvious that it is worth stopping the power plant for a couple of hours if the price seems to fall below the fuel and maintenance costs for those hours.
    - Start-up costs for hydropower with reservoirs are typically much lower than for coal and gas-fired power plants.

Note that historical costs are not a relevant factor for some types of power generation. How much it has cost to set up a wind power plant or buy a shipload of coal has no bearing on the question of whether it is profitable to produce power in the next 24 hours. The same applies to the concept of cost price[13] for hydropower, which has been discussed in several media in recent years:

- For the wind power plant, this is very simple - even if the cost price for the power plant is perhaps NOK 300 or 400/MWh and the price tomorrow is only NOK 40/MWh, it will be worthwhile to produce. The majority of the cost price has already been incurred - the investment cost will not be reduced if we do not produce tomorrow. The only thing you achieve by not producing is lower revenues.
- Similarly, the cost of the coal in storage is irrelevant - the cost of generating electricity from coal in storage is determined by the cost of acquiring a similar amount of coal again. If the coal was acquired for 100 EUR/tonne and the price at the time of production is 50 EUR/tonne, the owner will not be able to improve its finances by simply offering the power at a high price (based on 100 EUR/tonne).
- Nor does the concept of cost price for a hydropower plant have any significance for ongoing production decisions. The cost price for a hydropower plant is usually defined as the historical development costs spread over the life of the plant plus ongoing operating costs, such as the cost of regular maintenance and inspection. If the supply of water is sufficient, it may be profitable to offer power at significantly lower prices than the cost price, if the alternative is that the water is simply wasted. If access to water is limited, it will not be profitable for either society or the owner to offer the limited production that is actually possible at cost price.

The last point here can be illustrated with a simple example. In the figure below, we look at two periods with equal demand and equal total supply, and with different strategies among hydropower producers (represented by the low blue bars). The hydropower plant can produce a total of 6 units in the two periods. The green power plant can produce 4 units in each period, while the red one can

[13] In newspaper articles and comments, it is repeatedly emphasised that the MPE itself uses a figure of around 12 øre/kWh to describe the cost price of hydropower. The figure referred to is the price of concession power, which for 2023 was set at 11.77 øre/kWh (Olje- og energidepartementet 2022).

produce 2 units in each period. The demand is 6.5 units in each period. For simplicity, we assume that the demand is independent of the price.

We also assume that the inflow is known in advance and distributed with 4 and 2 units in periods 1 and 2, respectively. The inflow and reservoir are such that in the first period we must produce at least 2, but no more than 4 units of hydropower without wasting water. In period 2, we can then produce somewhere between 2 and 4 units, depending on the adaptation in the first period. We also assume that the hydropower sector consists of many producers, none of which are individually large enough to dictate the price development, but we discuss the significance of this below (and more generally in chapter 7.5).

We start by analysing the adjustment if hydropower production is sold at cost price, see Figure 6-. In this case, the entire inflow in period 1 is sold out, and it is the green power plant that sets the price. In the second period, we then only have 2 units of hydropower. With 4 units from the green power plant, we must use the red power plant to meet demand. The price in period 2 is therefore set by the red power plant.

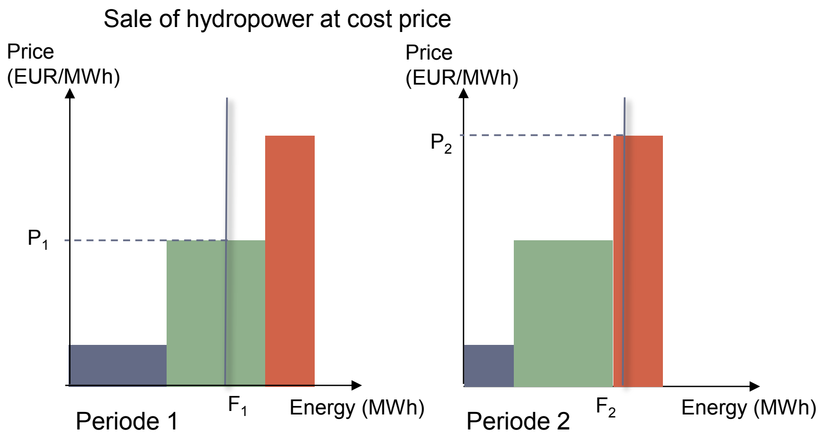

Figure 6- Sale of hydropower at cost price

Let us now see what happens if the hydropower producers change strategy and instead try to calculate the opportunity cost of producing in the first period. The hydropower producers will then realise that in period 2 they can at best get the high price P_2 (as above) or alternatively the lower price corresponding to the green power plant (P_1). Offering power in the first period at a lower price than P_1 therefore appears to be ill-considered. In the figure below, we therefore assume that the hydropower is offered for sale in period 1 at the price P_1.

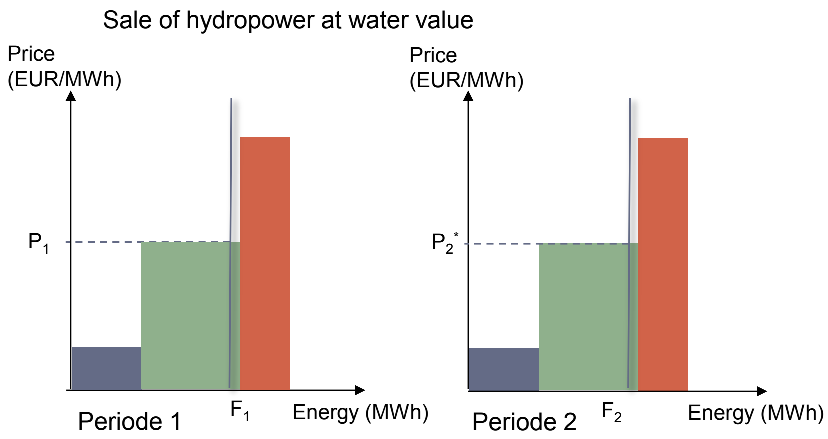

Figure 6- 4 Sale of hydropower at water value

It turns out that we can do without the red power plant, as the hydroelectric power is divided equally between periods 1 and 2 with 3 units in each. The green power plant becomes price-setting and produces 3.5 units in both periods. The price in period 2 is the same as in period 1.

It is better for society to cover the same demand at the price P_1 in both periods than P_1 in the first period and the higher P_2 in the second period. Prices are an expression of costs, and society does not have to pay for the red power plant at all because the water was well utilised and distributed in time.

For the hydropower producers as a whole, it would just as obviously have been better to sell 4 units to P_1 in the first period and 2 units in the second period to P_2 , compared with selling all 6 to $P_1 = P_2$ *. The challenge for the hydropower producers in the example is that none of them have market power - we have assumed that the sector consists of several small players. For each of them, it is best to withhold some production in the first period to compete with the red power plant.

If the hydropower plants wanted to secure P_2 in period 2, enough of them would have to stop producing in period 1 so that demand in period 2 cannot be met without the red power plant. They will not be able to do this unless they agree among themselves how to do it, or if the largest player controls half of the production and storage capacity (in this example). In that case, it would be a criminal offence of cooperation. See chapter 7.5 for a more detailed discussion of this.

Note also that for power producers, a bid in the spot market is largely the same as a (conditional) production decision. For hydropower producers with reservoirs, a bid and production decision is also a decision on how to utilise their reservoirs.

6.3 Hydropower producers must consider the future value of reservoir water

For most types of player, it is in principle not particularly complicated to consider the alternatives and thus the relationship between quantity and price (the bidding curves). Producers know exactly what they have to pay for gas or emission allowances, and the industry knows exactly how much they can pay for power and still have profitable operations - even though such information may be difficult to access for those of us observing from the outside. For hydropower producers with reservoirs, the situation is more complicated - also for the players themselves. The concept of **water value is** central to understanding the players' production decisions.

6.3.1 The cost of hydropower today depends on future conditions

Conceptually, the water value is the same as the opportunity value of the water 'behind' the turbine. The water value of a reservoir is defined as the marginal value of getting an extra unit of water in a reservoir today (Aam 2016). Water that is already in the reservoir can either be utilised for power generation 'now' or stored for later. For it to be profitable to produce 'now', the price 'now' must at least correspond to what we can expect to get for the same water at a later date. However, the value of storing water for later use is uncertain, and depends on future power prices and the likelihood that deferred power generation will not cause the reservoir to overflow and water to be lost later.

In practice, the water value is uncertain and complicated to determine. There are many factors to consider, many of which are unique to each reservoir. The list below covers most of what needs to be considered:

- How much water is in your own and others' reservoirs 'now'
- Risk of overflow (flooding) and loss of future inflow

- Manoeuvring regulations for the watercourse[14]
- Power prices at a later date, which depend, among other things, on
    - The supply of power later, which is largely determined by
        - Fossil fuel prices and emission allowances in the future
        - Production of weather-dependent power (solar, wind, rivers, ...) in the future
        - Future inflow of new water to own and other water reservoirs
        - How much snow is in the mountains and when it melts into water
        - Import opportunities from other bidding areas (explained further in 7)
    - Subsequent demand, which depends in particular on
        - Temperature later
        - Business activity later
        - Demand from other bidding areas (explained in more detail in chapter 7)

An important difference between different reservoirs is the relationship between size (storage capacity) and how quickly the reservoir can be filled (new water) and drained (power generation). Some reservoirs can be full in a matter of days or weeks, while others can take several years to fill if they are at the lowest permitted level (lowest regulated water level, LRV).

For the reasons listed above, the water value is generally different for all reservoirs. We have more than 1,000 reservoirs in Norway. When each individual producer creates production plans and bidding curves for their water power plants, production decisions are decentralised to those who know the relevant watercourse and power plant best.

Many of the conditions listed above are unchanged from day to day. Knowledge of business activity in 2024 and the temperatures in the winter of 2024/2025 does not change from 12 to 13 October 2023. The manoeuvring regulations for the individual facility remain fixed for many decades.

However, two important figures are updated weekly. Every Wednesday, NVE publishes statistics on the total level of water reservoirs and its estimates of snow storage. All producers can measure exactly how much they have in their own reservoirs. Many also have a good overview of their own snow reservoirs. However, no one has a comprehensive overview until NVE updates and publishes new figures.

Consequently, it is common practice among power producers in Norway to update water values once a week. The work is extensive and resource-intensive. Unless new and significant information emerges between the weekly publications of reservoir data, the water value estimates will remain fixed for seven days at a time.

It follows from this that how individual producers actually utilise their reservoirs says a great deal about what they think about future electricity prices. If a producer wanted to motivate other producers to behave in a certain way, for example to contribute to higher prices than we would otherwise have received - which is illegal - one way to communicate could be by showing detailed information about actual production and reservoir levels to other producers. This is one of the reasons why NVE's reservoir information is updated at an aggregated level and without specifying the situation in individual reservoirs.

[14] For all reservoirs, the licensing authorities have determined a maximum and minimum authorised regulated water level (HRV and LRV). Many licences also contain rules on the minimum permitted water flow, either continuously or periodically. These rules are called manoeuvring regulations and are designed to balance the interests of other users of the watercourse and natural values against the value of power generation.

In chapter 7 we take a closer look at water value calculation in practice and the relationship between water value and (expected) prices in bidding areas other than where the reservoirs are located.

6.3.2 The high price premium can affect production decisions

In autumn 2022, a new element was added to the operators' calculation of water value. Until then, the calculation of water value and the subsequent comparison between production now or later was independent of tax. On 28 September 2022, the government published a proposal for a high-price contribution, where the rate is set at 23 per cent of the electricity price that exceeds NOK 0.70 per kWh. On 21 October 2022, the Ministry of Finance informed the Storting in a letter that the Ministry believes *"the situation-specific high price contribution will be phased out by the end of 2024"* (Finansdepartementet 2022). In the national budget for 2024, the Government proposed to phase out the high price contribution from 1 October 2023.

Such a tax has two effects for affected manufacturers:

- Since the high price contribution only kicks in when the price of electricity is high, it will make it more profitable to produce at lower prices. This affects the players' expectations of future prices. This also affects the value of water and the utilisation of water reservoirs.
- The tax can also make it profitable to produce more than you would otherwise have done when prices are low.

In the winter of 2023, RME issued guidance on bidding in this regard (RME 2023). The background to this is that it is prohibited and punishable by law for participants in the wholesale market to submit bids that *"give or are likely to give false or misleading signals about supply, demand or price*" . [15]

RME concluded that taking the high price contribution into account when assessing water value is not a breach of the rules on market behaviour. On the other hand, RME considers that adjusting its bidding to optimise revenue may be illegal (attempted) market manipulation. The calculation basis for the high price contribution is the average price achieved per month. Bidding in the spot market with the intention of ensuring that the average price achieved is just below the cut-off point for the tax will be considered market manipulation.

6.4 The calculation of spot prices is performed by Euphemia

Euphemia was Queen of Norway from 1299 to 1312 and has little to do with the electricity market. Euphemia, on the other hand, is an acronym for EU Pan-European Hybrid Electricity Market Integration Algorithm. An algorithm is a complete and accurate description of the procedure for solving a computational task. The algorithm, which is used, among other things, to calculate spot prices in most of the EEA area, has thus been named Euphemia (NEMO Committee 2020). The algorithm has been developed over a number of years and is based on the algorithm used by Statnett Marked back in the early 1990s.

Euphemia is a practical implementation of the rules in the European Regulation on Capacity Allocation and Capacity Constraints Management (CACM)[16] . CACM specifies, among other things, the rights of the participants who must submit bids in the spot market and the obligations of the power exchanges and transmission grid companies. The regulation also regulates how bidding processes and routines related to price calculation can be changed. Work is currently underway to revise the rules on changes to the algorithm, among other things. There should be no doubt that the power exchanges and TSOs alone cannot change the algorithm at will.

[15] Regulation on grid regulation and the energy market (NEM), section 5-4 (a), FOR-2019-10-24-1413.

[16] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

The goal of the algorithm, and more generally of the calculations, is in practice very similar to what was the goal in 1971 for the co-ordination of power plants in Norway: to cover demand at the lowest possible cost and with the least possible flood losses and the like. The differences are primarily that the complexity of the calculations has increased and that advanced maths and IT resources have made it possible to bake more and more restrictions into the algorithm.

A simple example of the increase in complexity, and the benefits of the opportunities this provides, relates to how transmission capacity between bidding areas is taken into account. In 1971, a distinction was made between some regions in Norway and abroad, which in practice was Sweden. To be on the safe side before the calculations started, we were fairly cautious about how much of the installed capacity per connection was given to the algorithm. Prices and planned exchange between the zones were then calculated for one week at a time. Today, Euphemia can integrate the most advanced mathematical algorithms for capacity calculation we know directly into the price calculation. The result is that connections between countries and bidding zones are better utilised - there is no planning with limited flow if the value of greater flow exceeds costs, for example in the form of rationing or flood losses.

6.4.1 Price calculation is an extensive process

The spot price is determined in a single auction that sets the price for the next 24 hours in a total of 32 bidding zones covering 25 countries.[17] Each participant's bid is only known to the participant itself and the exchange the participant uses (closed bid). Participants can only submit one bid curve for each hour in their bidding zone (single bid sealed auction). The results are equilibria with a common price for everyone in the same bidding zone (uniform price, pay-as-clear). The equilibrium price is set so that total consumption in and exports from a bidding zone are equal to total production and imports to the same bidding zone. The price is determined so that the total cost of meeting total demand is minimised, taking into account the available transmission capacity between all bidding zones.

In simple terms, the process of calculating the spot price can be described as follows:

- Participants submit bids to 'their' power exchange by 12:00 noon. There must be a match between the bidding area and the location of the power consumption or power plants.
- The power exchanges collect the bids and forward them to the exchange responsible for carrying out the calculation. Bids in local currency are converted to EUR/MWh.
- The coordinating exchange performs the calculation and notifies the exchanges of the price in each bidding zone and the quantities to be moved between the bidding zones.
- Specifically, the algorithm looks for equilibrium prices that minimise the total cost of meeting the total demand.
- The power exchanges report back to the participants what the prices were and what volumes each bidder has bought or sold for each hour of the next day.

Between these steps, a number of checks are made to ensure that everything has gone as it should, that no rules have been broken, including the rules on market manipulation, and that the result is physically feasible. If errors are discovered, it may be necessary to recalculate or use simplified procedures with less efficient power exchange as a possible consequence.

[17] The 25 countries are Norway and 24 EU countries (all except Cyprus, Malta and Ireland). However, Euphemia is also used for a joint price calculation for Ireland and Northern Ireland, but this is done separately from 'our' price calculation.

6.4.2 Minimum and maximum price are required

In order for the algorithm to work, there are some minimum requirements for each individual bid. Most importantly, all bids must specify the desired buy or sell for the highest and lowest bid limit. The lowest price for which a desired buy or sell must be specified is -500 EUR/MWh (minus five hundred). The upper limit is 4000 EUR/MWh. Many people mistakenly believe that this was introduced to prevent power prices from becoming even more extreme. However, the reason is purely mathematical: in order for the algorithm to solve its optimisation problem, all bidding curves must start and end at the same minimum and maximum price.

If the equilibrium price is sufficiently close to the minimum or maximum price, a lower minimum price or higher maximum price will automatically be set according to specific rules.[18] The aim is for the market to determine the price, not technical conditions in or related to the algorithm.

The need for such rules is linked to the consequences for market participants if the equilibrium price hits the minimum or maximum price. If this happens, it is because the supply and demand curves do not meet. Equilibrium in the market can then only be achieved if buyers are allocated a lower volume than they have asked to buy at the maximum price, or sellers are allocated a lower volume than desired if we hit the minimum price. This is called curtailment. If this happens, the spot market has not succeeded in finding an equilibrium in the market and one must then find other ways to cover or reduce the question.

6.4.3 The algorithm supports many different bidding formats

CACM also sets other guidelines for bids than maximum and minimum prices. The starting point is that the participants should be relatively free to bid in such a way that they can best represent their costs by offering different volumes or formulate their willingness to pay for different volumes. However, in order for the calculation problem to be solvable within a reasonable time, the participants cannot design bids entirely at their own discretion.

However, operators can still choose combinations and price and volume almost as they wish. The most important restriction is that buy bids cannot have decreasing volume for lower prices, while sell bids cannot have decreasing volume for higher prices. Participants are also fairly free to create what we call block bids. Block bidding means that bids are linked across hours, for example, so that either the operator sells (or buys) a certain volume in several consecutive hours, depending on the average price for the hours, but independent of the price in the individual hour, or he sells (buys) nothing. This is one way of recognising that costs, especially for production, can be more complicated than a certain number of euros per MWh.

A significant disadvantage of block bids and other more advanced bidding formats is that they 'cost' computing time. Transition from hourly resolution to quarterly resolution in the spot market (Statnett 2022) will cost significant computing time. We are therefore cautious about opening up more bidding formats, or opening up the use of bidding formats designed for one or two countries in other countries.

6.4.4 Area pricing and system pricing are not the same

The spot price in a specific bidding zone is often referred to as the area price (e.g. the area price for NO1). A market participant that has bought or sold power on the power exchange is entitled to make

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[18] The Harmonised Maximum and Minimum Clearing Price (HMMCP) methodology for Single Day-Ahead Coupling (SDAC). Similar regulations exist for the intraday market. Article 41 of CACM requires the power exchanges to propose these rules and have them approved by the regulatory authorities in each country, or by ACER if they cannot agree.

a physical delivery at the spot price in the relevant area. Norway has five bidding zones, Sweden has four and Denmark has two.

The system price is a different concept and does not provide a corresponding right to physical delivery. Specifically, the system price is an index calculated on the basis of the bids in the spot market for Norway, Sweden, Denmark and Finland.[19] Unlike the spot price calculation, the limitations of the Nordic electricity grid are disregarded when calculating the system price.

The system price is used as a reference price for a large part of forward power trading in the Nordic region, see chapter 6.7. Since the system price is used in this way, it is regulated by the EU Benchmark regulation[20] .

6.4.5 Rules against market manipulation

The consequences for society of abuse of market power or manipulation of the spot price can be very significant. Norway has rules against manipulation of prices in the wholesale market and against abuse of inside information. The rules do not only apply to players who buy and sell power on the power exchanges. They also apply to grid companies. Among the latter, Statnett in particular has a responsibility, as the company holds a lot of information that, if publicly known, could influence prices in the wholesale market.

The rules in the Norwegian NEM regulations are in this area identical to corresponding rules in the EU, see for example chapter 9.2.2. The power exchanges have a central role in the follow-up of these rules. They are obliged to share information with RME and they have an independent responsibility to have and follow procedures that are suitable for detecting abuse.

In addition, the Competition Act contains general rules against market manipulation, cf. chapter 5.8.

6.5 Intraday market reflects last-minute information

While the spot market has one daily auction to determine prices and volumes for the next 24 hours, the auction format is completely different in the intraday market. There, the main principle is so-called continuous trading. Continuous trading is common in a number of markets - for example, shares and other financial securities and in commodity markets, but also in the property market. The principle is simply that when the buyer and seller agree, they execute the transaction at the agreed price. No exchange algorithm is needed for this.

Another significant difference is that there is no formal mechanism (algorithm) that links the price in one hour to the price in the next, as is the case in the spot market. Each hour is traded separately. Relative to the spot price, the intraday price may rise for one hour and fall for another.

Since the intraday market chronologically comes after the spot market, and is mainly used to take into account information that becomes known after the bid deadline in the spot market at 12:00 on the day before the operating day, the 'starting point' for price formation is precisely the spot price that was established in the spot market. If the motivation for the first trade is 'only' a moderate adjustment of expected consumption or production, the price change from the spot market will normally be moderate. However, if the wind forecasts go from full wind to zero wind, it is natural for prices in the intraday market to be significantly higher than in the spot market. It will generally be the

[19] https://www.nordpoolgroup.com/4ac5b1/globalassets/download-center/day-ahead/methodology-for-calculating-nordic-system-price---november-2022.pdf

[20] Regulation (EU) 2016/1011 of the European Parliament and of the Council of 8 June 2016 on indices used as benchmarks in financial instruments and financial contracts or to measure the performance of investment funds and amending Directives 2008/48/EC and 2014/17/EU and Regulation (EU) No 596/2014.

size of the volume change that determines the size of the price difference between the spot market and the intraday market.

The power exchanges and system operators for the transmission grid are preparing to introduce so-called discrete auctions as a supplement to continuous trading in the intraday market. This will be a supplement to continuous trading. The auctions will use the same exchange algorithm as the spot market (Euphemia) as far as it is suitable (there may be differences in the bid formats that are relevant).

Specifically, there will be an auction at 15:00 and another auction at 22:00 - both auctions will be for all hours (or all 96 quarters) of the next 24 hours. In addition, there will be a third auction at 10:00 the next day for the last 12 hours of the operating day. The purpose of these extra auctions is to make it easier for the participants to find counterparties, and to contribute to a more efficient utilisation of the transmission capacity than can be achieved with continuous trading.

6.6 Prices in the reserve markets can be understood as a function of spot prices

The reserve markets (see chapter 5.5, 5.6 and 6.1.1) differs from the spot market and the intraday market in that the product being traded can be described as a change in the agreed delivery to or from the market. The change is called either upward regulation (which results in higher production or lower consumption than agreed) or downward regulation (which results in lower production or higher consumption than agreed). The buyer of upward or downward regulation is a transmission grid operator responsible for the transmission grid. When Statnett buys upward regulation, it buys energy, while when Statnett buys downward regulation, it sells energy.

We need two dimensions to describe the different sub-markets for up and down regulation. One dimension is how quickly and for how long the regulation is to be delivered. The most common reserve types are FFR, FCR, aFRR and mFRR, and are briefly explained below. The second dimension is the content of the agreement and the timing of the agreement. Here, the options are contingency (capacity) prior to the operating hour and activation (energy) during the operating hour.

Standby agreements are entered into days (or more) prior to the operating hour. The contingency agreements oblige the seller to be on standby for upward or downward regulation during the operating hours covered by the agreement. A power producer that is on standby for upward regulation cannot offer all its capacity in the spot market - some will be tied up in the standby agreement. If the producer is on standby for downward regulation, he must ensure that there is some production to be regulated down if Statnett activates the resource during the operating hour. The need for reserves on standby varies over the year and between the different types of reserves.

The reason why Statnett and other system operators use different types of reserves is primarily because different resources are suitable for different tasks. Some can regulate up or down at lightning speed, but may not be able to maintain 'extra supply' for very long, while others may have completely opposite characteristics. The figure below is from Statnett and illustrates the difference between the four main types.

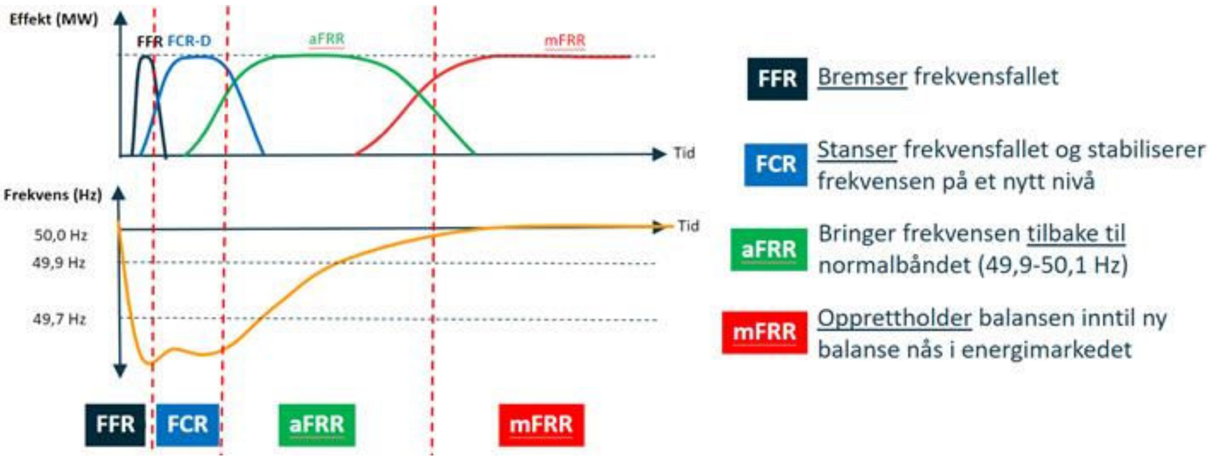

Figure 6- 5 Statnett's illustration of the timeline for a deviation in frequency and how different types of reserves restore the balance in the power system

When Statnett needs to activate reserves, it can choose between those with contingency agreements and resources offered without a contingency agreement.

Prices in the reserve markets in Norway are generally a function of spot prices and other costs for suppliers. The spot price is key because the energy sold in the reserve markets could alternatively have been sold in the spot market. This correlation is significantly weaker in countries without hydropower, which therefore also have significantly higher costs for reserves than Norway does. The explanation is quite simply that if a hydropower producer has to sell slightly more (less) energy than planned due to up- (down-) regulation, the water value is approximately the same. The producer may sell slightly less (more) than planned in the spot market the next day.[21]

6.7 Long-term markets are markets for uncertainty

As explained above, there are both organised and unorganised markets for long-term contracts. The mechanisms behind the price formation are in principle the same, but different durations and any special conditions will naturally also have an impact on the price(s).

The starting point is that an agreement entered into today for delivery over a period in the future must in reality be understood as two things. Firstly, it is an agreement on the supply of power. Secondly, it is an agreement that regulates uncertainty about future spot prices.

It is the second element here that is central to understanding price formation in the long-term markets. Since the parties in a long-term wholesale market agreement can always trade whatever quantities they wish in the spot market, an agreement on delivery at spot price during the contract period will have no practical significance - and such agreements are not common in the wholesale market. (However, this is common in retail markets.) It is therefore typical for long-term agreements to have a fixed price throughout the contract period. In PPAs, however, it is not uncommon for the fixed price to be adjusted year by year according to an agreed formula, for example linked to the consumer price index or similar. However, the general rule is that in long-term agreements, it is not the spot price, but some agreed price that applies. For the contract period, both buyer and seller replace the spot price they would have faced without the long-term agreement with the agreed price, cf. the example above in chapter 6.1.3.

The markets for long-term power contracts must therefore be understood as markets for uncertainty, where supply and demand for contracts reflect the players' costs of bearing price risk

[21] For further reading material on the reserve markets, we recommend the overview on Statnett's website: https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/.

and where the contract price reflects the risk premium. Below we explain in more detail what a risk premium is and how the long-term markets in the Nordic region are structured.

6.7.1 Risk premium is payment for assuming risk

Risk premium can be understood as the market value (cost) of replacing uncertainty with certainty. We can think of the spot price as a probability distribution and create a highly simplified example to show the relationship between the expected spot price, the price in the long-term contract and the players' attitude to risk.

For simplicity, we assume that the price is normally distributed, with expected value 50 and standard deviation 20.[22] In the chart below, the grey-blue curve represents the probability distribution of the spot price. (We return to the vertical coloured lines below).

As a starting point, assume that all market participants share the same expectations for the price. Therefore, there is no doubt in the market about the *expected price* (50) and *volatility* (standard deviation 20). For a *risk-neutral* end user, it does not matter whether she signs a contract with a fixed price of 50 or simply pays the spot prices whatever they turn out to be. The same would apply to a risk-neutral producer. If both sides of the market were risk neutral, neither would need to demand any form of hedging contracts.

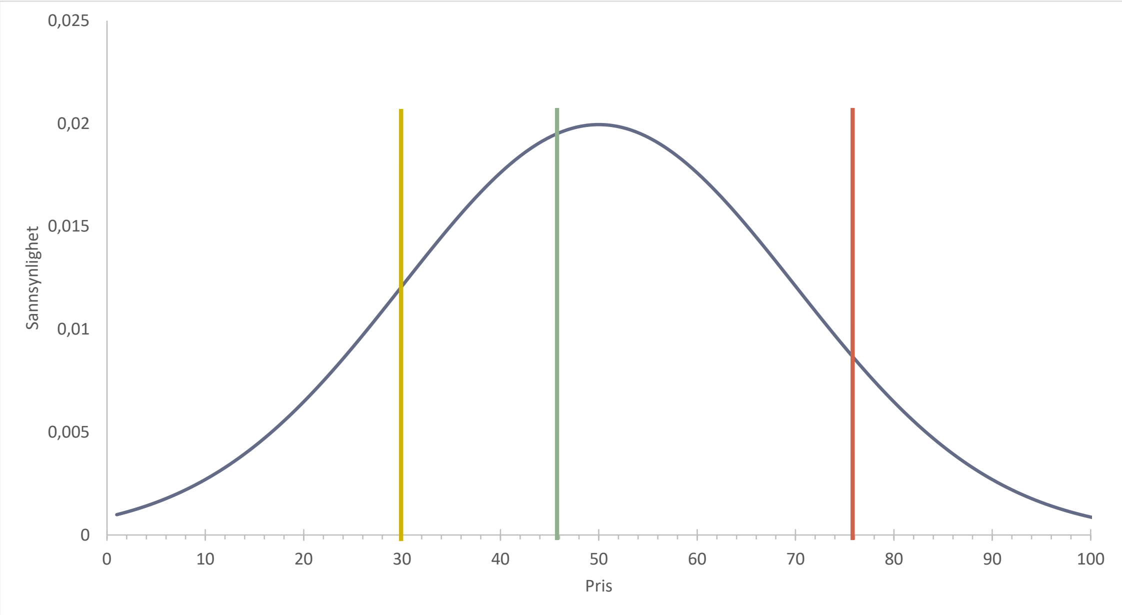

Figure 6- 6 Stylised example showing the relationship between expected price and forward price

Now let's see what happens if at least one player on the demand side is risk averse[23] . A simple example is if prices above 76 (the red line) are intolerable, and that prices are more attractive the more they are below 76. Thus, any fixed price up to 76 will be more attractive to this player than an unhedged position. And the lower the fixed price, the more attractive the contract is to this market participant.

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[22] Since this is an example, it does not matter whether this is øre/kWh, EUR/MWh or something else. In reality, the spot price is not normally distributed either, but the point here is to explain the principles.

[23] Risk aversion simply means that an actor is willing to give up something to replace uncertainty with certainty. Someone who buys travel insurance is willing to pay the insurance premium in exchange for the certainty of a certain amount of compensation if events occur while travelling.

However, there will be no agreement unless there is a counterparty. Assume, therefore, that there is at least one producer who has concluded that at prices below 30 (the yellow line), he will suffer an unacceptable loss. To avoid this, he is willing to sell at any fixed price above 30.

If these are the only risk-averse players in the market, and this is all we know about them, we don't have enough information to say what the contract price would be - but we do know enough to determine that there is an equilibrium price in this simplified market and that it is somewhere between 30 and 76.

Now let's assume that (for reasons unknown to us) they agree on a fixed price of 46 (the green line). What does this tell us?

a) Both buyer and seller get a contract that fulfils their requirements for security. This is of course obvious, but it is important to remember that both had the option not to enter into the agreement and both concluded that this agreement was better than no contract.
b) The manufacturer got 16 better than their pain limit, and the end user got 30 better than their limit. From this perspective, both have benefited from the contract - even before the start of delivery.
c) From another perspective, we can observe that the producer has 'given away' (paid) an expected income of 4 (46 minus 50) while the end user has received the same expected income. This 4 corresponds to the risk premium (before the event - ex ante) in this example, and is therefore a cost for one actor and an income for the other.

In reality, however, we cannot observe what each player thinks about the probability distribution for the future spot price. In practice, therefore, we cannot observe what corresponds to the grey-blue curve or the red and yellow bars. We cannot therefore calculate the risk premium as we have done above.

However, we can calculate the risk premium afterwards (ex post). The ex post risk premium depends on where the spot price ends in the delivery period. Both 40 and 60 are equally likely prices in this example, but in the former the producer 'receives' an ex post risk premium of 6 (46 minus 40), while in the latter he pays 14 (46 minus 60).

d) Contrary to what is common in public debate, we cannot simply interpret the observed equilibrium price (46) as market participants' best guess of future prices[24] , unless we know that all market participants are risk neutral or have identical risk preferences. Since we know that many market participants regularly hedge their positions in the power market, we should assume the opposite - that market participants have a certain degree of risk aversion. Risk aversion probably varies between market participants.
e) The information provided so far does not explain *why the* equilibrium price for the contract ended up at 46, and not just any other number between 30 and 76. However, we can deduce that in this example, the producer had higher, or stronger, risk aversion than the end user.

The last point is a general result; market participants with the strongest risk aversion often pay the highest risk premiums for a specific contract. And market participants with the lowest risk aversion may be paid to avoid risk. *Therefore, the risk premium is not necessarily a cost* - it depends on the risk aversion of all market participants.

[24] In the example, the expected value is 50 and the forward price prior to delivery is 46. If the price in the delivery period turns out to be 68, this does not mean that the market was wrong - 68 is within the probability distribution. We can compare this with the roll of the dice: the expected value of a roll of the dice is 3.5, even though no one expects to get exactly that when they roll the dice. Any result from 1 to 6 is likely.

Different market players are typically concerned with securing different time frames, for example, so that electricity suppliers dominate the market for the next few months while producers dominate the market for longer contracts. Empirical studies suggest that the risk premium can be understood as a function of time to delivery (Benth, Cartea og Kiesel 2008). In this case, both producers and end users may end up seeing their relevant risk premium as a cost. A significant factor in the Norwegian market is that the resource rent taxation for hydropower reduces the hydropower producers' need for price hedging, all other things being equal. This may lead to somewhat higher demand for price hedging from the buyer side of the market than from the seller side. Another observation is that the probability distribution for spot prices is asymmetric (Povh 2009). We have now learnt that very high price peaks are possible, but prices far below zero for a long time and in many bidding areas are still considered unthinkable.

We can therefore summarise that the observed market price of a long-term contract is equal to the sum of the expected spot price and the ex ante risk premium. However, since we cannot observe the ex ante risk premium or the individual player's expectations of future spot prices, it is difficult to assess whether the observed market price of long-term contracts is the result of efficient markets or not. If we subsequently observe a high ex post risk premium, we do not automatically know whether this is due to inefficient or lack of competition, a lack of need to hedge prices on one side of the market, unfortunate geographical division of the market, or simply that the probability distribution for electricity prices has a wide range of outcomes (Bjørndalen og Hagman 2020).

6.7.2 Price hedging in the Nordic region is often based on the system price

Participants on the supply and demand side of the power market use long-term agreements to limit price risk and, to some extent, volume risk. While the time horizon for forward contracts entered into via power exchanges is relatively short (in theory up to 10 years, but in practice significantly shorter), bilateral agreements and PPAs can be entered into for several decades.

There is an important correlation between on-exchange and off-exchange contracts. For a power company that is asked to make an offer to a long-term buyer (typically industry), the ability to buy some of what the customer is asking for via the exchange will reduce the risk the power company assumes in making the offer. For the participants in the power market, it is therefore not a question of either an exchange or PPA and bilateral agreements - they are dependent on both sub-markets functioning appropriately.

As the electricity price can vary from one bidding zone to another, the place of delivery is an important parameter for long-term agreements. In PPAs and other direct agreements between a producer and a buyer, the place of delivery will be specified, most often as bidding zone or at specified address(es).

If it is a financial agreement, the term 'reference price' is often used to denote the location. The term 'system price' is important here (cf. chapter 6.4.4). The system price is used as the reference price in much of the futures trading in the Nordic region. The reference price is the price against which the long-term contract is settled, cf. the price that varied from NOK 430 to 913/MWh in the example in chapter 6.1.3.

A market participant in a specific bidding zone that wishes to hedge a volume in 'its' bidding zone will then consider two contracts - first a contract that applies to the system price and then a contract that applies to the difference between the system price and the price in the bidding zone the market participant wants. The last contract type here is called EPAD - Electricity Price Area Difference. There could potentially be an EPAD for each bidding zone, while there is a system price contract that may be relevant for all bidding zones. Depending on the circumstances, a market participant in a specific bidding zone may find it sufficient to hedge the system price and take the risk that the difference between the system price and the price in the bidding zone does not vary more than the market participant can accept.

The advantage of this division is that there are potentially more participants who want price hedging against the system price than against the individual bidding zone. This increases the chance that the market for forward contracts with the system price as a reference price is efficient and liquid. By definition, there will be fewer participants interested in any given EPAD than there are for contracts with the system price. There is therefore a great risk that the market for the individual EPAD contract is inefficient and has poor liquidity. The dichotomy is well supported in financial literature, which points out that complete elimination of all risk is not optimal for the participants (Ederington 1979, Williams 1986).

In this context, effective means that the risk premium is lower than it would otherwise be. Efficiency is important to ensure that price hedging does not become too costly.

Good liquidity means that it is relatively quick to execute the trade when the player wants to - a counterparty can be found relatively quickly and the agreement can be entered into at a relatively known price. Should the player wish to change the price hedge after it has been entered into, for example because the desired volume has changed, it is an advantage if the contract that was initially used is liquid.

If the spot price in a specific bidding zone has a high correlation with the system price, it may be pointless to use EPAD. Price hedging against the system price can then provide sufficient risk relief for market participants. Conversely, if the spot price in a bidding zone has a weak or highly variable correlation with the system price, a hedging strategy without the use of EPAD may not be very effective.

As a curiosity, it is worth mentioning that the system of system price contracts and EPAD was developed by the Nordic players themselves in the late 1990s. At the time, the authorities paid no attention to this.

6.8 Guarantees of origin and electricity certificates

In addition to the electricity price, the prices of guarantees of origin and electricity certificates are relevant for both power producers and end users of electricity.

6.8.1 Guarantees of origin are a voluntary scheme

Guarantees of origin are regulated by the EU Renewable Energy Directive[25] , which states that all electricity producers that generate renewable electricity are entitled to be issued a guarantee of origin per MWh of electricity produced. The Renewable Energy Directive also states that if an electricity producer is to document to a consumer that the power sold is renewable, this must be done using a guarantee of origin [26]

The sale of guarantees of origin provides renewable energy producers with revenue per MWh of power generated. Revenues from the guarantees have a positive impact on the profitability of projects and can thus influence investment decisions. In some European countries, producers must

[25] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.

[26] To prevent double counting, where the 'green' characteristics of power produced from a particular power plant are sold multiple times, a tradable certificate of origin is issued for each MWh produced by 'approved' power plants. An electricity customer who wants to document consumption of renewable energy must purchase guarantees of origin and ensure that they are cancelled.

choose between receiving government subsidies, for example in the form of feed-in tariffs or electricity certificates, and the right to sell guarantees of origin. The impact of the guarantee on profitability then depends on whether the market value is higher than the public subsidy.

Power producers are free to sell their guarantees of origin. EU regulations do not contain any guidelines on the trade or use of guarantees of origin. In practice, guarantees of origin are traded both within countries and across national borders. The use of guarantees of origin by consumers of electricity for their own climate reporting is essentially voluntary, and the extent to which guarantees of origin or other methods are used varies among companies on the consumption side.

Trading in guarantees of origin has similarities with electricity certificates. Although there may be a so-called time stamp on a guarantee of origin, trading typically takes place in such a way that the seller guarantees that the buyer will receive an agreed amount of certificates by a certain date, and that these are linked to a specific year. In most cases, it does not matter to the buyer whether the guarantee certificate relates to power produced in summer or winter, for example - the important thing is that it is produced in the agreed calendar year. The transaction between buyer and seller is not affected by the fact that the guarantee certificates are not issued until production takes place.

Norway is a net exporter of Guarantees of Origin. For Norwegian hydropower producers, this has historically provided an attractive, but until a few years ago relatively moderate income. However, in parallel with the rise in electricity prices across Europe since 2021, prices for guarantees of origin have also risen sharply, cf. Figure 67. Figure 6-. The reasons for this price increase are probably not entirely coincident with the reasons for the price development of electricity. The supply of guarantees of origin for Nordic hydropower or wind power in Germany, for example, is not affected by the supply and price of natural gas. On the other hand, many assume that lower than expected hydropower production is one of the reasons for the high prices in 2022 and 2023. Rising demand for renewable energy is also highlighted as a likely cause.

Since guarantees of origin are issued according to production, the market value can influence production decisions and thus also electricity prices. It is unregulated production that can be affected to the greatest extent. The higher the value of the guarantees of origin, the lower the spot price can be before it may be worthwhile to stop power generation. Even if the spot price is negative, it can still be profitable to produce from wind power plants if the guarantee of origin has a high enough value. However, the situation is different for hydropower with space in the reservoirs. The water can be stored for later power generation. The production decision then depends on the water value, which reflects the expected value of postponing production, and on how the price that can be achieved for guarantees of origin is believed to be at the relevant time for later production. However, the price of guarantees of origin does not vary as much as spot prices, and will probably be about the same now as at a later date. Therefore, the spot prices and the water value will largely continue to determine the time of production of regulatable power.

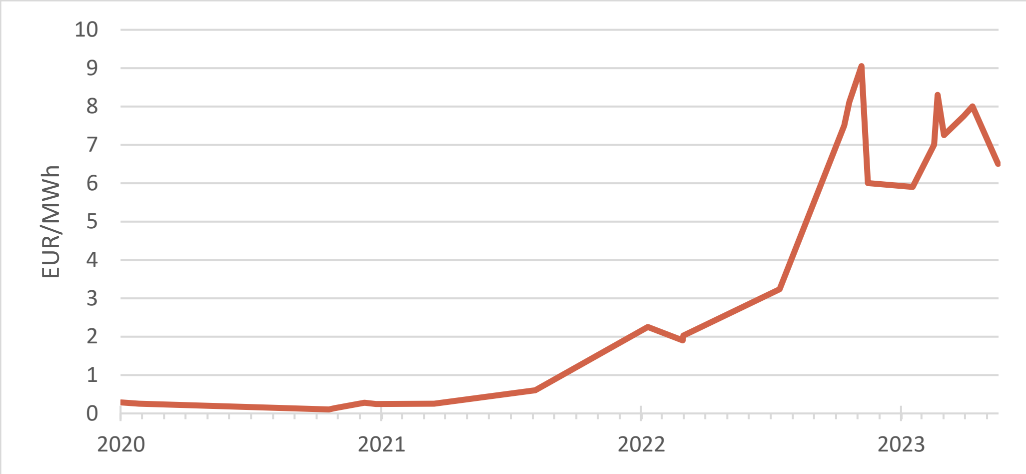

Figure 6- Price development for guarantee of origin for Nordic hydropower (Source: Green Power Hub, Montel)

6.8.2 Electricity certificates

In 2012, Norway and Sweden established a joint market for electricity certificates. The scheme means that for power plants that were commissioned before 31 December 2021, the owner receives a certificate for every MWh they produce (for up to 15 years). End consumers who were covered by the scheme in Norway (mostly everyone except power-intensive industry) have been obliged to pay for electricity certificates corresponding to a certain proportion of their consumption (quota).

The aim of the joint scheme was to increase the production of renewable energy by 28.4 TWh in Norway and Sweden combined. Of this, Norwegian consumers will pay for 13.2 TWh, while Swedish consumers will pay for 15.2 TWh. Swedish consumers must also pay for a further 18 TWh, so that the electricity certificates will contribute to a total of 46.4 TWh of new electricity production.

The unique feature of the scheme is that the price of electricity certificates is determined by supply and demand. In practice, demand is determined by the authorities through the size of the quota consumers have to pay for. Supply is determined by actual production in the power plants covered by the scheme.

As the *expected* annual power production from the power plants that are included is greater than the total purchase commitment (46.4 TWh annually), the market price for the electricity certificates has been less than NOK 1 per MWh (corresponding to less than NOK 0.01/kWh). In the initial phase, however, the price was between 15 and 20 øre/kWh.

6.9 Grid tariffs and authorised revenue for grid companies

The electricity price committee's mandate does not include network tariffs. However, for the sake of completeness, we have included a brief overview of how grid tariffs are set. Given the committee's mandate, it is primarily other aspects of the grid companies' responsibilities that are important, such as facilitating and connecting new customers and new production.

Since 1991, the price of electricity - the electrical energy - has been set separately from the price of transporting energy to the customer and from the power plant. While the electricity price is a market price determined by supply and demand, where the seller's income is uncertain, grid tariffs are set so that the total income for the grid company does not exceed the authorised income.

The 'task' of the tariffs is to distribute the payment for the services provided by the grid company between the grid customers in such a way that the customers contribute to the efficient operation and, not least, development of the electricity grid.

In Norway, the grid companies themselves determine the grid tariffs within the framework set out in regulations from the MPE[27] , while RME determines the authorised revenue.

The principle for authorised revenue is that the grid companies as a whole should have their actual costs covered, including a reasonable return on the equity that the owners have made available to the companies. The total revenue is distributed between the grid companies so that those with the lowest costs over time in relation to the scope and complexity of their tasks receive a somewhat higher return than those that are less efficient. This means that it is worthwhile for the companies and their owners to keep the costs of the electricity grid down and at the same time maintain the grid so that interruptions due to faults or bad weather are as few and as short as possible.

Although a significant proportion of the costs for grid operations are capital costs that do not change much from year to year, unless interest rates change, the cost of energy losses in the grid is a not insignificant cost. This means that when electricity prices rose sharply from 2021, the costs that the companies must cover also rose. As a result, the authorised income of the individual grid company also rose.

A few main principles have been established for the design and calculation of the tariffs to be paid by grid customers:

- Both power producers and end users must pay for both connection to and use of the electricity grid.
    - Use of the grid occurs when the producer produces (input) and the consumer uses electricity (output). Both producers and consumers are therefore faced with so-called usage-dependent tariff elements.
    - For connection, you have to pay both to establish the connection, for example through a so-called construction contribution, which covers (a share of) the costs of building a connection to the existing grid, and to be connected (fixed annual fee, regardless of actual consumption or production).
- Since the permitted income is given for each grid company, any favourable tariff for one customer group leads to increased costs for another customer group. Principles have therefore been established for how the payment should be distributed between different customer groups - for example between producers and users of electricity, and between customers who draw electricity directly from the transmission grid and, for example, households that draw from a lower grid level.
- The producers' payments are also regulated by a regulation from the European Commission.[28] This sets upper and lower limits for power producers' annual grid payments. In Norway, Sweden and Finland, the average payment for feed-in must be between zero and EUR 1.2/MWh. In Denmark and large parts of the continent, the limits are zero and 0.5 EUR/MWh. In many countries, producers do not pay tariffs at all, but in Norway and Sweden, among others, producers' payments are close to the maximum limit.
- Tariffs (the payment from those who use electricity) can be differentiated based on grid conditions. Grid conditions typically mean the voltage level at which power is withdrawn - there is a big difference between a large factory and an ordinary household. However, what

[27] Regulations on economic and technical reporting, income framework for grid operations and tariffs; FOR-1999-03-11-302.

[28] Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

you use the electricity for is not a grid-related factor - whether the factory produces aluminium or data services is irrelevant.

- The main structure is the same for all withdrawal customers:
    - An annual fixed payment, completely independent of how much you use in the year in question. In simple terms, this should reflect the annual costs of metering, billing and invoicing.
    - An annual fixed payment that distinguishes between small and large customers at the same grid level, for example between a large and a small factory, or a large and a small household. This is often referred to as a power link. The principles for setting this vary between customer groups. This tariff element is often combined with the point above, so that there is one so-called fixed element for large customers and another for small customers (and possibly with a finer differentiation between the largest and smallest).
    - A usage-based payment, which in practice becomes a payment per kWh consumption.
- For households and other relatively small grid customers, the rules for allocation between usage-based and other tariff levels are different and more standardised than they are for customers who use more than 100,000 kWh annually.
    - For the smallest customers, the usage-based elements must account for *at least* half of the customers' total payment to the grid company, while for larger customers, usage-based elements must *not exceed* the marginal cost of withdrawal.
    - The fixed charge and power charge will thus be a *maximum of* half of the payment for small customers and a significantly larger share for other customers.
- If, at the end of the year, it turns out that the total revenue was higher than the income framework indicates, the tariffs for the following year must be reduced accordingly.

In practice, network tariffs are a complicated pricing problem because the cost function for network services is complicated and the network is a so-called natural monopoly. Pricing according to the traditional theory of optimal prices will therefore not generate sufficient revenue for the grid companies. As a compromise, several tariff levels are therefore used as explained above.

7 Power exchange, market dynamics and security of supply

As you know, electricity prices can vary in time and space. In chapter 6 we focused on the temporal dimension and explained that the price of the same kWh depends on how far in advance of the operating hour it was sold. In this chapter, we will explain the spatial dimension. This is particularly important for understanding production decisions for hydropower, and thus the price formation in the Norwegian power market. It also provides us with sufficient concepts to discuss security of supply and what we often call market dynamics - how markets are linked geographically and over time.

In addition to the explanations in this chapter, bidding zones and effects on prices are discussed in chapters 12 and 15.

7.1 Scarcity of grid capacity contributes to different value in different locations

The power grid consists of a number of power lines "criss-crossing", connected at points (nodes) with transformer stations or so-called switch fields. Regional and local distribution networks are connected to the overlying network in one or more nodes. Both the individual node and the lines connecting them are designed for a certain load (power transmission). Between some nodes, or groups of nodes, the current transmission may be such that there is in practice always sufficient capacity, while between other groups of nodes there is often a need for (demand for) transmission that is greater than the capacity. This is the starting point for defining what we call bidding zones.

A bidding zone is the smallest geographical region that is such that the transmission system operator can guarantee that the participants can enter into buy and sell agreements as they wish (prior to the operating hour). This means that the spot price in all nodes in the same bidding zone is the same at all times. Bidding zones are therefore sometimes called price zones.

This means that nodes that are not in the same bidding zone do not necessarily receive the same spot price. Some areas have significantly higher production than consumption, while in other areas the opposite is true. We may also have large localised variations in inflow to the hydropower plants. The power situation in the various bidding areas can therefore be quite different. This gives rise to different area prices. They can still have the same price if the implicit demand[29] for transmission happens to be less than or equal to the available transmission capacity.

Bidding zones are important for managing the limitations of the power grid, and the limits are set where there is long-term limited capacity. Such limitations are referred to as structural bottlenecks. Norway is currently divided into five bidding zones, NO1 to NO5.

The price differences between bidding zones generate so-called congestion revenues. These are collected by the system operators. In Norway, these revenues are used to cover the authorised revenue set by RME for Statnett.

If we had not operated with different bidding areas, the market results (spot market, intraday market and future markets) would not have taken into account the fact that the opportunities to transfer power from one area to another are limited. In that case, Statnett and the other transmission grid operators would have to pay the players who have entered into agreements that cannot be physically realised to refrain from doing what they have just agreed with their counterparties. In

[29] The demand for transfer is called implicit because it arises as a result of the players' combined buy and sell bids in each bidding zone. If one area has a net buy bid of 10 and another area has a net sell bid of 10, participants *implicitly demand the* opportunity to transfer 10 units from one area to the other.

some countries, such as Germany, electricity customers have to cover large costs every year for such countertrading and redirection. [30]

The bidding zone system also has an operational security aspect. Without bidding zones, the role of the spot and intraday market in terms of planning the physical operation of the power system hour by hour (see chapter 6.1.2) would be very limited. Norway is a vast country where most of the power generation is, for good reasons, located in different places than much of the consumption. Too few bidding areas would have made Statnett's task of ensuring instantaneous balance in the power system virtually unsolvable.

To explain the spatial dimension of price formation in the power market, we start with a simple sketch. Initially, we consider two bidding zones where demand is a fairly simple curve and supply comes from power plants with a very simple cost structure. Then we will introduce hydropower plants, which have a more complicated cost structure.

7.1.1 Simple sketch without hydropower

I Figure 7- we see two power systems with very different costs and thus power prices. In zone A, costs and prices are low, while in zone B, prices are high.

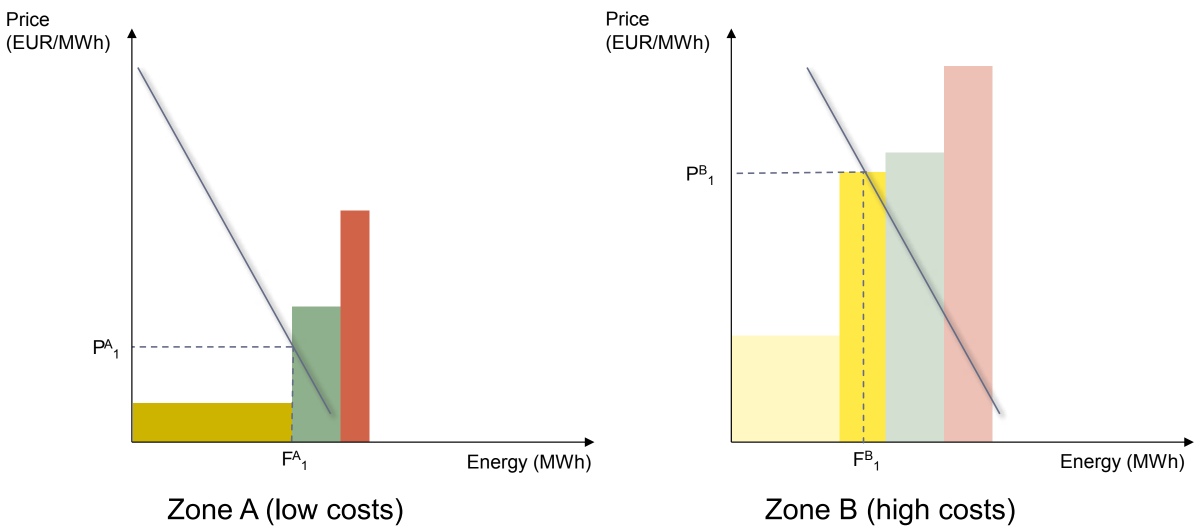

Figure 7- Two bidding zones without power exchange

I Figure 7- the grid capacity is sufficient to carry out all profitable power exchange between the zones. In zone A, prices go up, consumption goes down and production goes up. I Figure 7- only the cheapest power plant was in use, but with power exchange, the second cheapest power plant is also fully utilised. In zone B, production is reduced (the yellow power plant is taken out of operation), while consumption increases. For the two zones as a whole, total production costs decrease, while total consumption remains unchanged.[31] The socio-economic surplus is highest in this figure, both for the zones as a whole and for each zone individually.

[30] The total costs in Germany for reserves and power redirection have risen from just over EUR 500 million in 2013 to EUR 4 billion in 2022 (BDEW 2023).

[31] The figures are drawn so that the change in consumption in each zone cancels each other out and total consumption is thus constant (per assumption). In reality, consumption in both zones will change depending on the price elasticity, and the total effect may be different from zero.
Note also that we completely ignore transmission losses in the electricity grid in these figures.

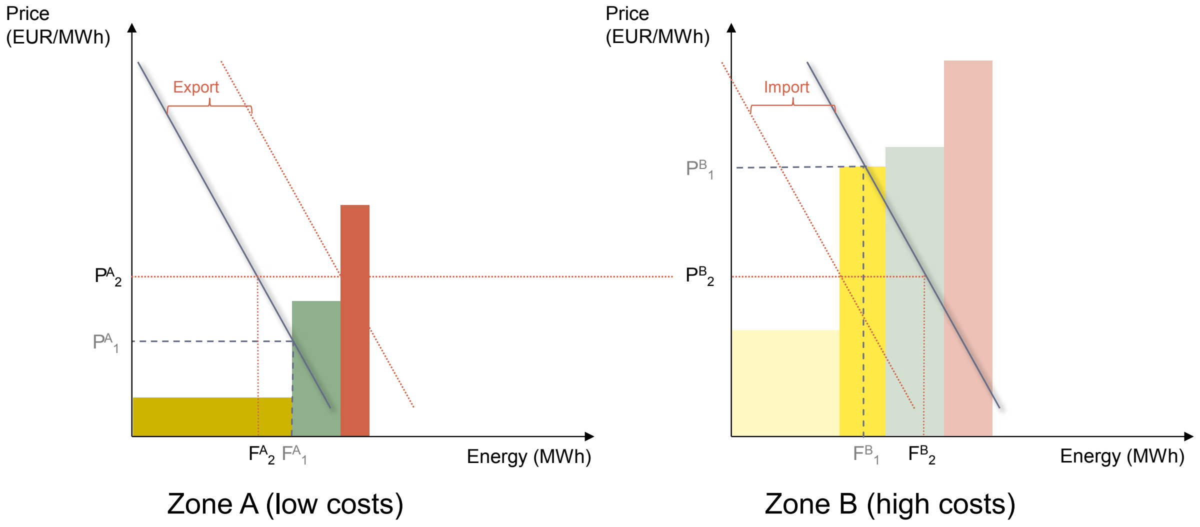

Figure 7- Two bidding zones with large exchange capacity

I Figure 7- transmission capacity is limited, so that all opportunities for profitable trade cannot be utilised. Prices become more equal, but not equal. Also in this situation, prices in zone A are higher and zone B lower than without connections. For the zones as a whole, the total production costs are lower than initially, but higher than if the exchange capacity did not restrict trade. For each zone, the socio-economic surplus is somewhere between the baseline and the situation with unlimited capacity.

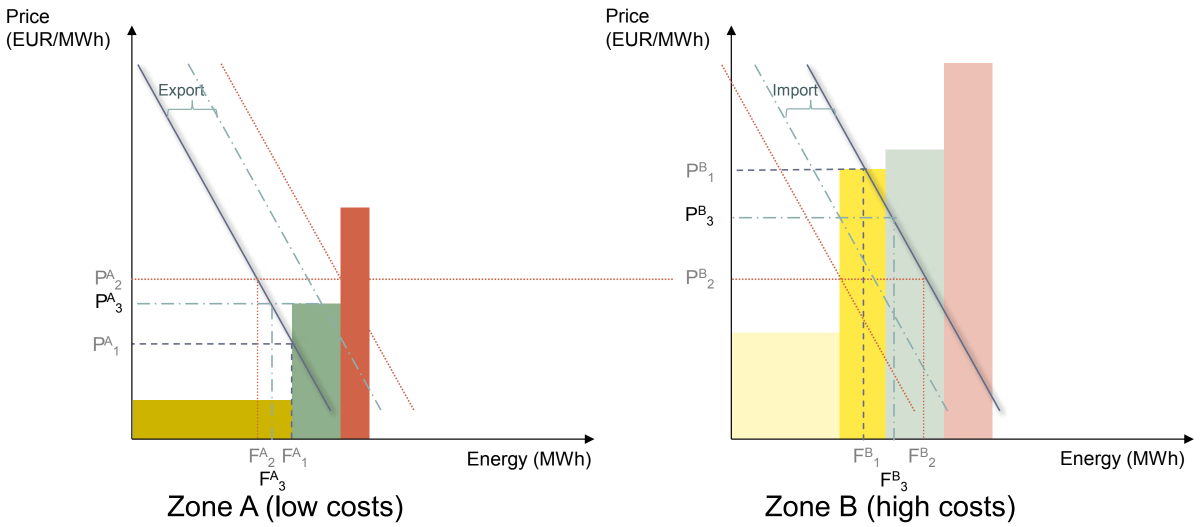

Figure 7- Two bidding zones where exchange capacity limits trade

The similarities between the figures above and the real power market are few, but important. One of them is that demand is generally a falling curve. This means that those who use electricity do not value every MWh equally. The reason for this is that the value a MWh creates for the buyer varies and depends on what the buyer uses it for. With the prospect of high prices, at least some end users will take steps to reduce their electricity consumption - for example, reducing heated space or using a different energy carrier. In the long term, it may be possible to reduce energy demand by changing production processes.

Another significant similarity is that different power plants have different costs and that the composition of power plants is not the same in all areas. This means that trading, up to a certain level, can reduce overall production costs or increase the possibility of valuable electricity consumption. In zone B, consumption that has higher value creation per unit increases than consumption in zone A, which decreases.

If we had inverted these figures so that the supply curve was the same in both zones, differences in the demand curves would have been the driving force behind price differences.

A significant difference between the figures above and reality is that in reality it varies which zone has relatively low costs at any given time. For 2022, the Norwegian bidding areas in the north, NO3 and NO4, can be perceived as zone A, while the zones in southern Norway can be perceived as zone B. In autumn 2023, NO2 can be considered zone B, while the rest of Norway is zone A. If consumption grows significantly in the north, while supply increases in the south, for example with offshore wind, these roles can be reversed. The same will happen if, or when, the differences in inflow to the reservoirs or in wind conditions in the different bidding areas become large.

7.1.2 Sketches with hydropower

Simple figures have limited explanatory power. For example, if all but the red power plants in the figures above are hydropower plants with reservoirs, we cannot use the figures to explain why they have different costs. The figures can illustrate a given situation where the water values are represented by the heights of the columns, so the value of reservoir water is generally higher in zone B than in zone A, not why this is the case. In the short term, the water value acts as a marginal cost for the individual power plant. Trading can then occur just as in the example above. To explain how water values are formed, we need to create an example with two periods, cf. chapter 6.3 where we explained the concept of water value in general and that the water value depends, among other things, on import and export opportunities.

The only thing we can conclude from the figures above is that in zone A, the supply of hydropower is so high that power exchange is required for the price in zone A to begin to approach the price in zone B. In the figures with exchange, the dark green power plant starts to produce, while the yellow power plant in zone B saves water for later use.

In the example above, we saw that when trading between two areas, power will flow from the area with the lower price to the area with the higher price. Cheap production capacity in A displaces expensive production in B. Exports from A to B will increase until prices are either the same (it is not profitable to export more) or until there is no more available transmission capacity (it is not possible to export more).

In the same way that power trading moves power between areas, reservoirs provide the opportunity to move power from one period to a later period. How much energy we can move depends on how much reservoir capacity we have available. To simplify the presentation, let's assume that we only have two periods and that we can move power from period 1 to period 2 by withholding production in period 1. If the ability to move power (store water) is sufficiently large, we will get the same price in the two periods. If the ability to move water is less, we will get different prices.

Introduction to the bathing chart

In the following figures, we use so-called bathing charts. It is simply a horizontal axis where we measure quantity (energy) and two vertical axes where we measure price. Since we 'only' have two vertical axes, we only have two periods - period 1 and period 2. The charts are constructed in this way:

- The horizontal axis and the two vertical axes together form an open rectangle that can be perceived as a bathtub.

- At each end of the bathtub, we draw lines showing the demand in each period. As usual, demand in period 1 is drawn as a descending curve from left to right, while demand in period 2 is drawn descending from right to left.
- The distance between the vertical axes (the width of the bathtub) shows the total supply (amount of water) available in the two periods. We can think of period 1 as spring, summer and autumn (often referred to as the filling season) and period 2 as winter (the drawing season). We ignore the possibility that there is power generation other than hydropower.
- The bathtub is poorly suited to representing uncertainty purely graphically. In reality, the supply is uncertain, as we do not know the future inflow, but in the figure the width and thus the amount of water is known. In the figure, this known inflow applies to both period 1 and period 2.
- I Figure 7- line segment A-C represents the amount of water transferred from the previous period to period 1 plus the inflow in period 1. Line segment B-C is the size of the reservoir, while line segment C-D is the inflow in period 2.
- In order not to make the figure more complicated than it needs to be, we assume that period 2 is the last period. In this case, we do not need to take into account that it may be wise not to utilise the entire inflow for period 2.

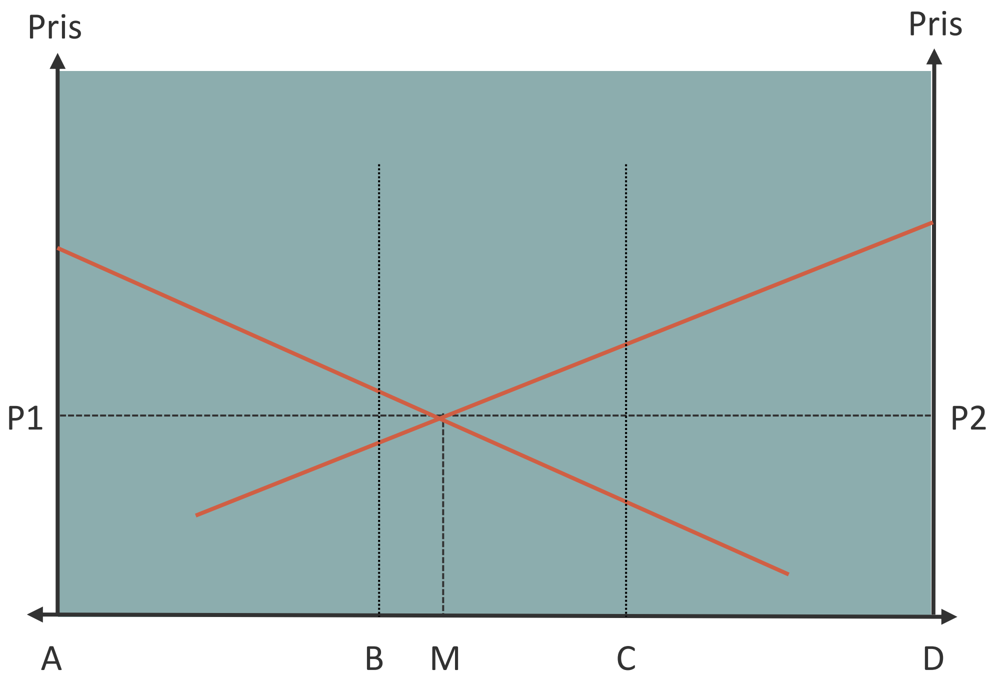

Figure 7- Hydroelectric power with two periods, reservoir size sufficient to equalise prices

With these assumptions, consumption in period 1 is equal to the line segment A-M. The quantity M-C is saved for the next period, where consumption becomes M-D. Due to the size of the reservoir, the water value and market price are the same in both periods; P1 = P2.

The impact of limited reservoir size
Let's see what happens if the magazine is significantly smaller.

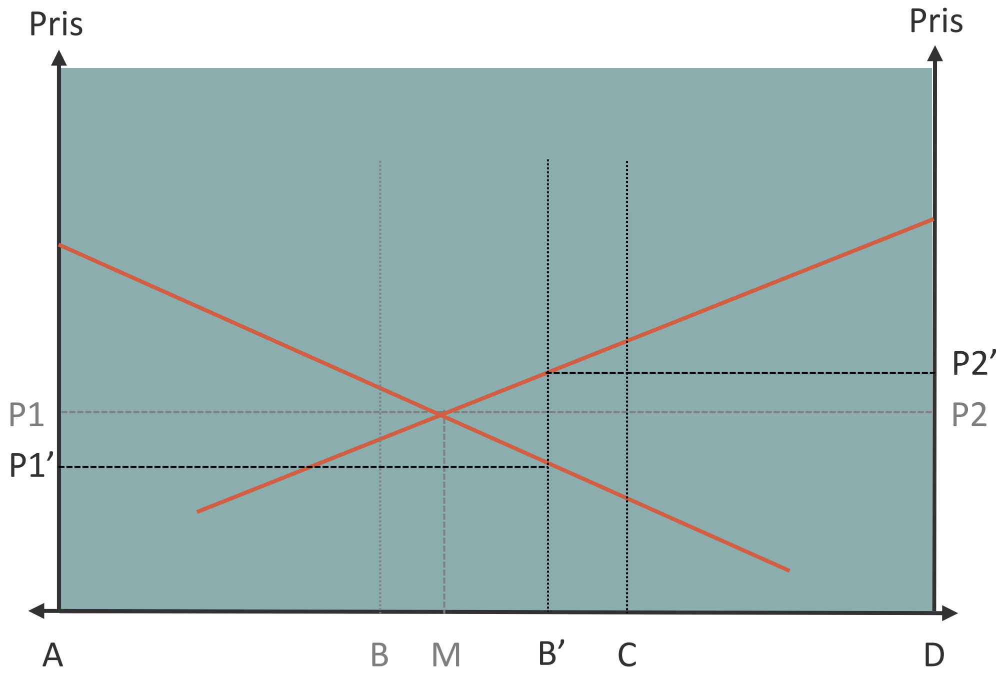

Figure 7- Reduced magazine size68

Since the distance A-C remains (by assumption) the same, the point indicating the left-hand extremity of the magazine must be shifted. Point B is therefore moved to the right, past M and to B', so that the reservoir size is now B'-C. The reservoir is then no longer large enough, and we get different water values and different market prices in the two periods, cf. Figure 7-. The water value and price in period 1 falls to P1', while the price in period 2 rises to P2'. Consumption in period 1 is A-B', while consumption in period 2 (B'-D) is limited by inflow C-D, the reservoir and the ability to move water to the next period.

Prices would have been even lower if the inflow in period 1 was much higher. This corresponds to shifting point A to the left. This is roughly what happened in NO1 and NO5 in the summer and autumn of 2023 - the reservoirs here are not large enough to handle all the inflow for the winter.

Effects of other bidding zones with different prices
Then we can look at the effects of trading with other bidding zones. Let's assume we have two bidding zones; a hydropower zone and 'abroad'. We know from Figure 7- that it is the sign of the price difference that determines whether there will be imports to or exports from the hydropower zone, once the water value has been determined. We start by looking at a situation where prices abroad are very high in the short term. This has the same price effect as an increase in demand within the hydropower zone, so we draw this as a shift to the right of the demand curve for period 1, see two variants drawn in Figure 7-. Visually, it looks like an upward shift, but the point of increased demand is that the desired volume at different prices is higher than before the increase.

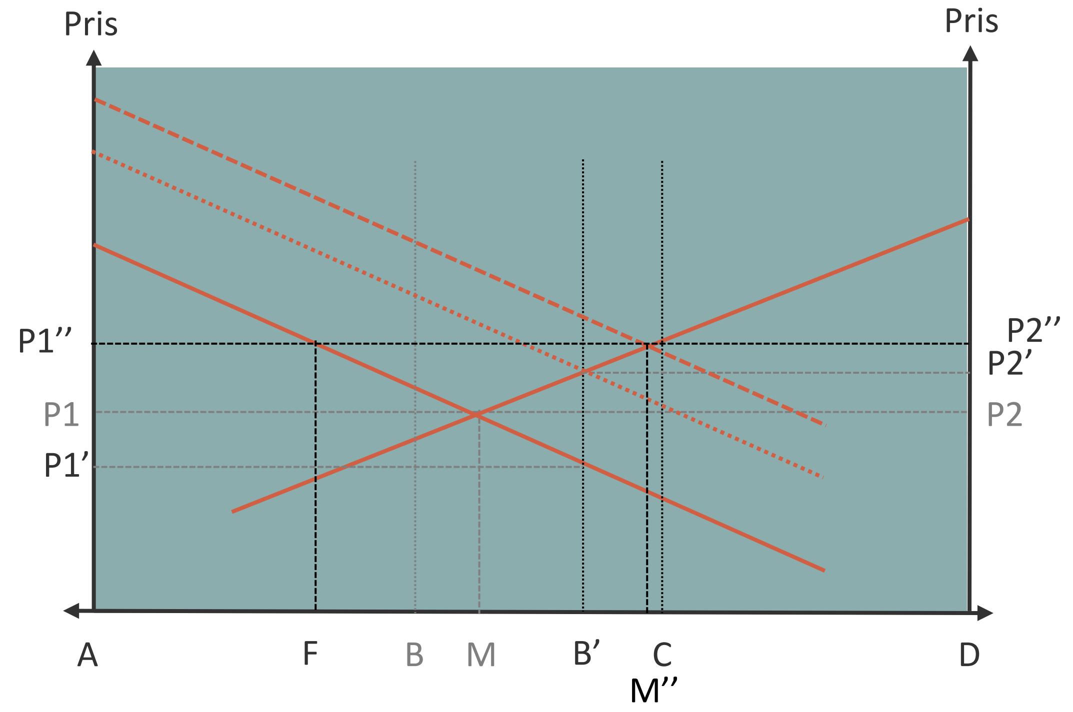

Figure 7- Foreign demand in period 1

Before we interpret Figure 7-, we must note that it is only the demand in period 1 that has increased, while it is assumed that demand in period 2 is unchanged. Nor have import opportunities been taken into account, either for period 1 or period 2. These are simplifications to expand the example step by step.

With the upper demand curve in Figure 7- the 'small' reservoir B'-C is large enough to give us the same water value and the same price in both periods; P1''' = P2'''. Domestic consumption in period 1 at that price will be A-F, while exports in the same period will be F-M'''. The total demand in period 1 is large enough for the 'last water' in period 1 to be stored and utilised in the next period. I Figure 7- the demand in period 1 was so low that we had water 'left over', which could be sold cheaply - it could not be transferred to period 2 anyway.

With somewhat lower demand from abroad, such as the finely dotted demand curve between the top and bottom, we would have had the 'old' price for period 2, P2', in period 1 as well. Here, the B'-C reservoir is just large enough to ensure the same price in both periods. If demand from abroad had been somewhat lower, the price in period 1 would have been lower than P2'.

The question now is what the demand from abroad does to prices. The figure shows that the price in period 1 increases regardless. Whether the price also increases in period 2 depends on the size of the increase in demand in period 1 and the size of the reservoir. If you read the figure carefully, you can see that if the reservoir was as large as B-C, we would have equal prices in both periods with the chosen assumptions.

Next, let's look at the impact of exports only in period 2. The demand curve for period 2 has a shift to the left, the price in period 2 increases to P2''''', while it remains P1' with the 'small' magazine B'-C. If the magazine size had been larger, we would have had a lower price in period 2, while the price in period 1 would have increased.

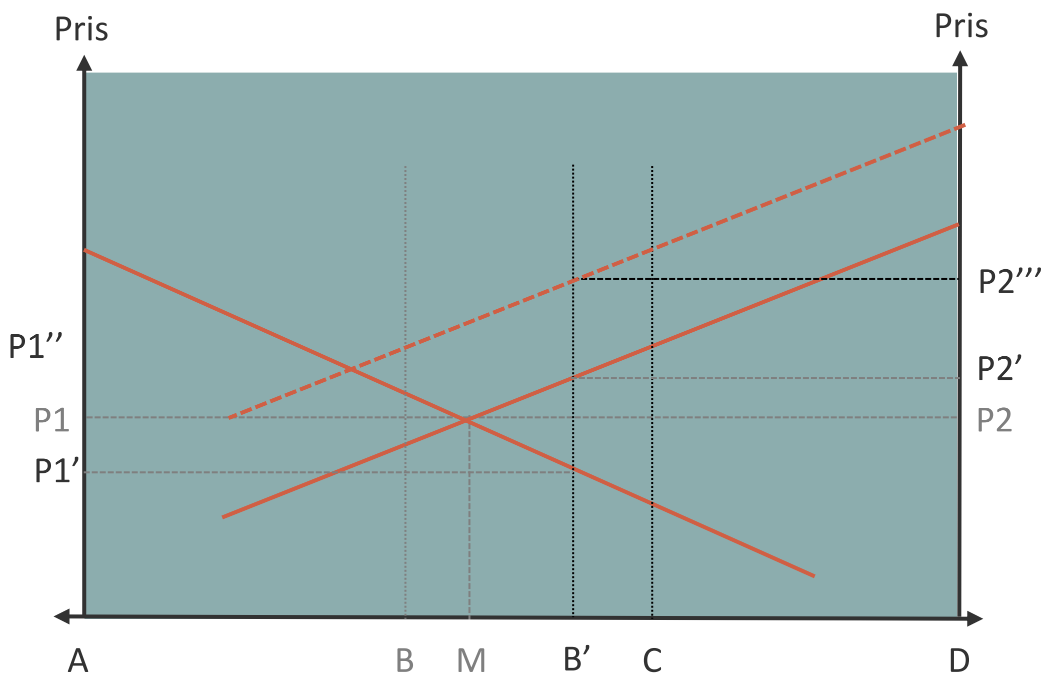

Figure 7- 7 Demand from abroad in period 2

Similarly, we can study the impact of increased demand in both periods. With the small reservoir, the water value and market prices will be different in periods 1 and 2; P1''''<P2''''. If the reservoir is larger, the water values can be the same in both periods. The figure shows that export raises the price level, all other things being equal.

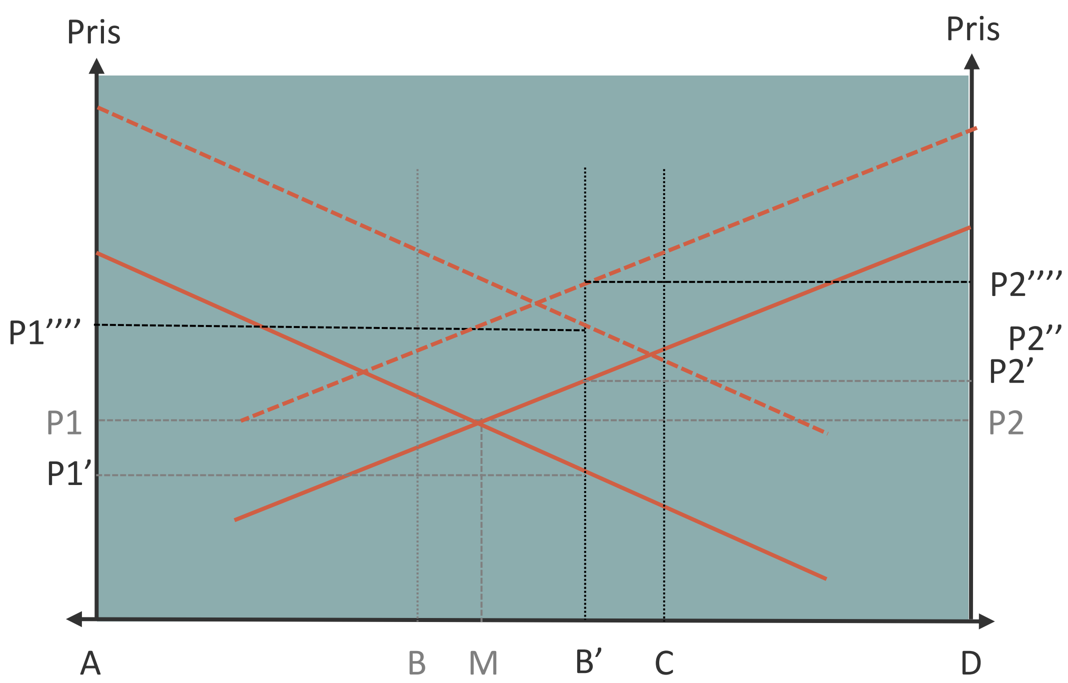

Figure 7- Increased demand in both periods

The figures above show the effects if the trade opportunity only went one way - export from the hydropower zone. If the trade opportunities go both ways, we must also illustrate that the supply in the hydropower zone can be greater than hydropower alone. Figure 7- below shows a simple way to illustrate this.

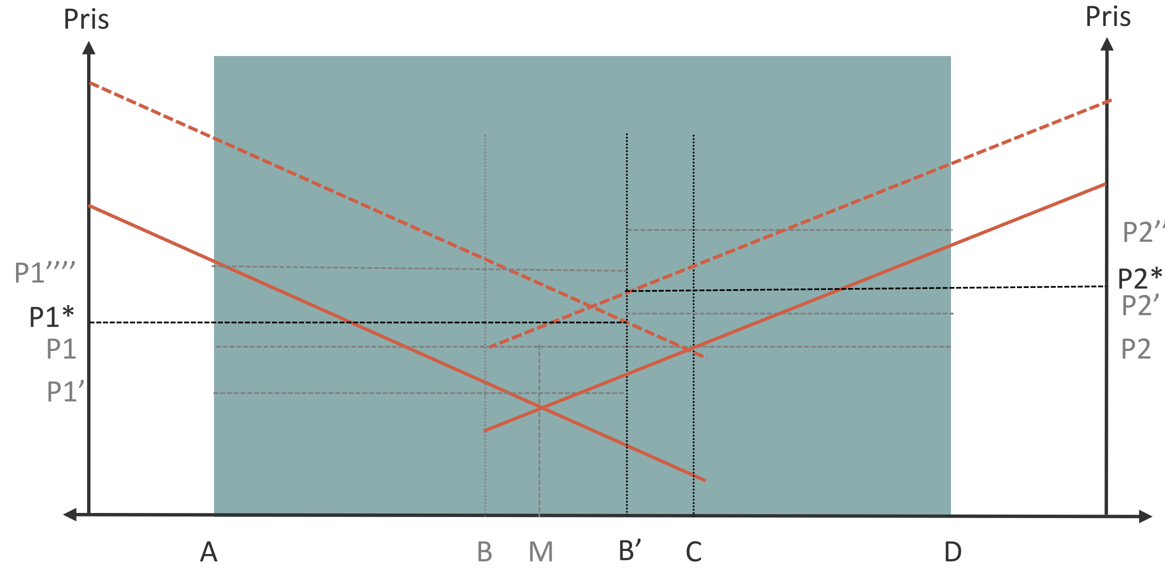

Figure 7- Water values and opportunities for both import and export

Figure 7- makes two elementary but important points: imports and import opportunities pull prices down, while exports and export opportunities pull them up. Which effects are greater depends on supply and demand from abroad:

- If we imagine that the supply from abroad was very large, at a very low price, we would have had to move the vertical axes (the walls of the bathtub) further to the left and right. This would have resulted in lower water values.
    - If, on the other hand, we imagine that the supply from abroad is very small and/or comes at a very high price, the figure will approach Figure 7- and thus give higher water values.
- Similarly, we can imagine that if demand from abroad is very high, for example because access to power abroad is severely limited in relation to supply, we would have to draw the dotted demand curves even higher in the figure, resulting in higher water values.
    - Conversely, if supply abroad significantly exceeds demand, for example during periods of high production from solar and wind power, the energy demand directed towards the hydropower zone will be very low

7.1.3 From sketches to reality

The reality is of course more complicated than the sketches above. The most important simplification we have made above is that future inflow (corresponding to C-D in the figures above) is not a known figure, but a random quantity about which we have limited knowledge. It is true that we have good time series of inflow to individual reservoirs and watercourses, but these show that inflow can vary greatly from year to year. Reservoir allocation must therefore reflect the fact that the amount of inflow is uncertain, even though we know a good deal about the probability distribution. In addition, we can be fairly certain that the past does not represent a perfect picture of the future. The history shows, among other things, that the expected inflow per year is increasing, while the variation both within the year and from one year to the next is also increasing.

Another important simplification is that in reality we have not one, but around one thousand reservoirs in Norway that producers must utilise. The mathematical formulation of the decision problem is therefore much more complicated than the figures above.

Nevertheless, the figures above can be used to understand how power exchange and water values are related. For example, if a power market model is used to determine the impact of a specific interconnector on prices, it will be the expected difference between P1 and P1* and between P2 and P2* that is examined.

The power companies' and analysis agencies' models that calculate water value can be understood as a collection of bathtubs as shown in the figures above, with different widths, and which together express the probability distribution of future inflow. Of course, the models also take into account other types of supply than hydropower - but then it is no longer a question of simple sketches as we include above.

Norway has around half of Europe's water reservoirs. These represent a unique advantage in that an increasingly smaller proportion of power generation will be regulated, and that large-scale storage of electricity is costly. Since the inflow to the reservoirs is uncertain, hydropower producers have an uncertain amount of water at their disposal over time. Every day and week, they must therefore choose how much reservoir water to use now and how much to save for later. Their most important tool for this optimisation is the calculation of the water's alternative value - the water value (Aam 2016). The water value of a reservoir is defined as the marginal value of having an extra unit of water in a reservoir today. For large reservoirs, the current water value will typically be equal to the expected water value in future weeks. However, the water value may deviate from this if maximum or minimum limitations on reservoir filling are encountered. The individual producer calculates the water values in light of the individual reservoir's special characteristics, inflow conditions, regulatory provisions, society's expectations and political requirements, and not least the prices the hydropower producer expects to achieve in the future. Without effective price formation in the wholesale markets, calculating the value of water would be very demanding in practice.

What would the last two years have been like without the last two international connections?
The sketches above can serve as a starting point for some reflections on what price formation in Norway would have been like if the last two interconnectors had not been established. The Energy Commission's report states that the effect of these interconnectors is difficult to determine with certainty, partly because they are relatively new and partly because they were opened in an extraordinary situation (NOU 2023: 3). Statnett estimates that these interconnectors accounted for 10 per cent of the price increase from 2021 (Statnett 2023), Sintef has performed sensitivity analyses that show that prices in southern Norway in autumn 2021 were 15-25 øre/kWh higher with the two international interconnectors than they would have been without (Mo, Wolfgang og Øyn Narvesen, Vurdering av kraftsituasjonen 2021-2022 2023)while the analysis company Volue has calculated that the interconnectors accounted for 25 per cent of the price increase.

With reference to Figure 7- we can think of the situation with and without the last two connections primarily as different situations for period 1: The connection to the UK in particular opened up a more 'direct' route for supply and demand from the UK into the Norwegian market. The connection to Germany can be perceived to a greater extent as a more direct channelling of supply and demand from Germany, but which has nevertheless reached Norway via Denmark (DK1/Jutland). If we were to plot this in Figure 7-, we would have drawn the left outer wall of the bathtub a little further to the right, and the dotted demand curve somewhat lower.[32] Given the situation with significant energy shortages both on the Continent and in the UK, the import opportunity is of limited interest, and it is therefore natural to emphasise the somewhat lower demand curve. As the more detailed analyses show, this would have resulted in somewhat lower prices in southern Norway than we actually saw. However, prices would probably have been very high compared with the period before 2021, simply because the price expectations for period 2 and later would have been linked to the high gas prices and the major energy shortage caused by the war and preparations for it, so that the international cables were primarily used for export.

Prices for summer and autumn 2023

In view of the bathing card diagrams above, some reflections can be made on the significant price differences between NO2 and the rest of Norway. The reasons for the price differences between NO2 and the rest of Norway in autumn 2023 are complex.

- Prices in NO1 and NO5 in particular are low, mostly well above zero, and they vary little over the course of the day. Various reservoirs that are *almost* full and have a high probability of overflowing set the prices in these bidding areas. The grid capacity of other bidding areas (demand in NO1 and NO5 from other bidding areas) is not high enough to counteract the risk of flooding and overflow. The water value will then be low in NO1 and NO5.
- In the summer of 2023, we had many hours with negative prices and also hours with significantly higher prices in the same week, in several bidding areas, including NO2.
    - The very low, or negative, prices reflect situations where reservoirs cannot hold back more water.
    - During the hours of very high prices, it has not been possible to meet demand without using water from reservoirs that could hold water for later periods. These reservoirs have a high water value and then set the price when demand is high, while when demand is low they are priced out of the market (i.e. they conserve water until the value of the power is higher).
- A significant difference between NO2 and the two other bidding areas in southern Norway is the overall size of the reservoir and the size of individual reservoirs. Norway's largest reservoir, Blåsjø, with approximately 8 TWh of storage capacity, is located in NO2. Total reservoir capacity in NO2 is 33.9 TWh, while total consumption is 35-39 TWh per year and expected annual production is 46 TWh. In NO1, total consumption is just over 36 TWh, total production is about half (17.7 TWh), and total reservoir size is 6 TWh. Another difference is that NO2 has a very large exchange capacity abroad.
    - Larger reservoirs make it possible to hold back water for later. When the sum of demand in NO2 and from abroad minus imports from abroad, NO1 and NO5 is greater than unregulated production in NO2, it is the water values that set prices in NO2.
    - A heavy downpour over southern Norway at the same time as the storm Hans in late summer 2023 could have lowered prices in NO2 if it had resulted in consumption and demand from abroad being covered by unregulated production or water reservoirs becoming full.

[32] Alternatively, we could illustrate the trade opportunities by adding some horizontal sections to the demand curves, where these sections are linked to the price level abroad. The disadvantage is that the figures would be even more complicated. However, it would then have been easier to see why trade opportunities in both directions anchor water values to the price level in neighbouring countries.

7.2 Impact on investments

The figures above emphasise short-term conditions. This means a time perspective so short that the players do not have time to adapt production and consumption opportunities by making new investments. However, the consequences of, for example, a new connection between bidding areas, or a change in reservoir size, can extend significantly beyond the next period. If we compare Figure 7- and Figure 7- they are drawn so that the trading opportunities lead to higher prices in both period 1 and period 2.

A relevant follow-up question is then what the effect of rising prices on the players and the market will be. Will anyone consider investments, so that the supply or demand curves for subsequent periods will have a different location? For example, it is reasonable to assume that if prices appear to be at a level that is higher than the cost of new production facilities, some will see the opportunities and apply for a licence and possibly establish new production capacity. Similarly, it can be expected that some will take measures on the demand side that will lead to lower demand in the future than we would otherwise have had. Both will lead to lower prices in the future than the figures in isolation suggest.

Collectively, these are often referred to as dynamic or second-order effects, as opposed to the first-order effects shown in the figures above. Dynamic effects make it difficult to assess the overall impact of major changes in a market. In the electricity market, this may involve the impact of building or shutting down very large power plants (for example, conventional nuclear power, where new plants are often well over 1,000 MW) or extensive changes in the design of the market. The most obvious example where this is relevant in Norway is the issue of interconnectors. When Statnett applied for a licence for the interconnectors to Germany and the UK in 2013, a socio-economic analysis of the projects was included. Many have noted that the price impact was expected to be a few øre/kWh.

Many have criticised these analyses, partly because prices in Norway increased much more than a few øre/kWh during the period when the interconnectors were introduced.[33] But regardless of what one might think about the quality of the analyses, it is essential to realise that the ears mentioned are first-order effects. The dynamic effects on prices generally run in the opposite direction to the first-order effects. Systematic and quantitative evaluation of the outcome space for such dynamic effects would in practice be far too extensive a task to analyse. The reason is that the number of conceivable responses to a specific change, which must then be analysed individually, cannot be limited in a simple and objective manner.

7.3 Exports and imports are market results, not operator decisions

In addition to explaining how prices in different bidding zones are related, Figure 73 shows Figure 7- and Figure 7- also show that exports and imports are outcomes in the market. As explained above, bidding in the spot market takes place by each market participant submitting a bid for how much they wish to buy or sell - in their bidding zone. We can again look at the dark green power plant in zone A in Figure 7-. If it submits its bid as the curve indicates (produces a quantity corresponding to the width of the column, given that the price exceeds the height), it will be the market's other bids and the capacity of the power grid that ultimately determines whether the power plant will produce

[33] We refer to Chapter 4 for a more detailed discussion of the reasons for the high prices from 2021. And although the analyses at the time hardly took into account that gas and electricity prices on the continent could be as high as they became, it may be useful to clarify that what we have experienced from 2021 to now is only a small part of the story for these connections, or one outcome from a probability distribution.

or not. I Figure 7- exports are roughly equal to the capacity, but the owner does not know whether it is 'his' electricity that is sold to zone B. All (both) producers in zone A receive the same price.

Figure 7- implicitly suggests that if the price in zone B were even higher, the price in zone A would still be the same. In the short term, it is not *how much higher the price in zone* B is than the price in zone A that determines whether there will be exports - it is the fact that the price in B is higher than in A. The relative scarcity is greatest in zone B and therefore there will be exports from zone A.

In the longer term, however, there will be a correlation between the water value of the dark green power plant (the height of the pole) and the price level in neighbouring areas. This is explained in chapter 7.1.2.

Price dispersion from one bidding zone to another is therefore related to both the size of the exchange capacity (see, for example, the difference between Figure 7- and Figure 7-, or on Figure 7-) and the size of the price difference. The hourly price difference is related to the duration curve (how long prices are high and low) for the price of trading partners. If trading partners always have a price of 100 and NO2 always has a lower price than this, there will be full utilisation of available export capacity at all times. The UK has been about this for a long time. If, on the other hand, the trading partner (as an extreme example) has a price of 200 half the time and zero price the rest of the time, a NO2 price that is always above zero and below 200 will result in zero net exports for the period as a whole.

7.4 Trade and security of supply are closely linked

Figure 7- also provides a good starting point for explaining the relationship between power exchange and security of supply.

Trading has reduced Norway's vulnerability to random variations in inflow, temperature and power consumption. With today's installations, the expected (average) inflow to the hydropower plants is around 137 TWh. In a dry and cold year, the inflow may fall to around 95 TWh, while consumption may be higher than normal (NOU 2023: 3). Thanks to multi-year reservoirs, power production can still exceed 95 TWh in dry years. If we have two or three dry years in a row, import opportunities are particularly important. In wet years with inflow of up to 171 TWh, the export opportunities are very valuable, as we can then be paid well for the surplus power. Current production capacity and consumption provide a net export of 20 TWh during a normal year. In dry and wet years, exports will be around 20 TWh lower or higher than this. There is no one-to-one correlation between inflow and export, because Norway has reservoirs with the capacity to store water over several years. Due to higher expected consumption growth than production growth, NVE expects that Norway will not have a power surplus in normal years in 2028. Imports occur when Norway has higher prices than neighbouring countries. For exports, we must have lower prices than neighbouring countries. See chapter 12 for a more detailed discussion of the power exchange with neighbouring countries.

Trade opportunities also expose us to vulnerabilities in other countries' power systems. One example is the throttling of Russia's gas exports to Europe, cf. chapter 4 and 10. Gas is an important fuel in many countries, and the price effects of reduced availability spread far beyond Europe. Another example is nuclear power in Finland and elsewhere in Europe. Nuclear power plants are very large production facilities. Operational problems in one nuclear power plant can lead to several nuclear power plants of the same type also being shut down for safety reasons. Experience shows that it takes a long time to assess the extent of such safety problems. The problems have contagion effects on neighbouring countries, including Norway, cf. the experience of France and its extensive unforeseen problems in the summer of 2022.

Trading is also important for short-term operational reliability. In the Nordic region, we have long experience of joint reserve markets in the power system (see also chapter 6.1.1). By sharing reserves, each country can manage with less. Good trading opportunities also contribute to more stable prices.

Prices and price formation are of crucial importance for reservoir utilisation, power flows between regions, sensible energy use and for decisions on investments in energy use, power production and grids. Prices influence producers and consumers to adapt so that capacity is utilised. Persistent price differences between regions emphasise the market value of expanding grid capacity.

When energy is scarce, market prices will rise. In the short term, a high price will reward those who can increase production (those with water in the reservoir) and those who can reduce power consumption. Adaptation will usually be greatest among power producers with flexibility and large consumers, and least among households. In the longer term, high prices will stimulate reduced consumption, better opportunities to utilise price differences (for example through more flexible production processes) and increased production.

The Bye report (Bye, et al. 2010) addressed the need for more and more accurate prices in the electricity market in order to fulfil key security of supply objectives. Over time, increased *opportunities for* price variation will lead to more uniform prices both regionally and over time. Because scarcity varies between different times and seasons, and from place to place, it is important that prices are set for a sufficient number of times and geographical points. An opposite development (less frequent pricing and fewer bidding areas) makes it more difficult to manage periods of scarcity and will weaken the profitability of necessary investments. An upper limit on prices will create doubt among power producers about the value of conserving water, make it difficult to make socially sensible reservoir utilisation and, in the worst case, may increase the risk of rationing. Consumers will then not receive signals about the shortage and thus cannot contribute to solving the shortage challenge. For security of supply, it is important that price formation is as free as possible, but also that it takes place within a well-considered framework.

7.5 What about market power and strategic bidding?

With the large price differences we have had internally in Norway in recent years, some question whether the hydropower producers in the south, first in all of southern Norway and now most recently 'only' in NO2, are taking advantage of the situation and pushing up prices.

The Commission has not made a separate assessment of this question. The Norwegian Competition Authority wrote in an opinion piece that there were examples of unfortunate behaviour in the Norwegian power market in the 1990s, but that they have no indications that the high prices in 2022 are due to violations of the Competition Act in Norway (Skjæveland og Søreide 2022).

In order to be able to make money from the abuse of market power, a producer must succeed in 'creating' scarcity by withholding water, or pricing the water very high, ensuring that the value of what is actually produced is greater than what may be lost in subsequent floods or must be sold at a reasonable price to avoid flooding. Hypothetically, it is conceivable that a player could set the price low during hours of export and then set a high price for their water when we switch to import.[34] A prerequisite for success is therefore that the probability of flooding is relatively low. Such a strategy is also more risky (in purely financial terms) the greater the uncertainty about prices and demand in associated bidding areas.

[34] Unless the player controls a significant part of the supply side, such behaviour can potentially lure others into 'opposite' behaviour - producing a lot when/if the first player ensures that the price is high, and producing little otherwise. This is why cartels generally have internal conflicts of interest.

If a participant bids the same resource at a low price in some hours and at a high price in other hours of the same day, this may be an indication that the participant is attempting to exploit its position. The power exchanges that operate the spot market and the intraday market are obliged to monitor the participants' bidding, partly with the aim of detecting any attempts at such strategic bidding. RME is responsible for monitoring this.

Abuse of market power and market manipulation in the electricity market can have major negative consequences for electricity customers and is illegal and punishable by law. There are extensive European regulations, and in Norway there are also separate and detailed provisions on market manipulation and insider trading in the NEM regulations. In Norway, RME, the Norwegian Competition Authority and the Financial Supervisory Authority of Norway are responsible for supervising various parts of the electricity market. The financial power market (the futures market) is covered by financial legislation, while the physical power market (the spot and intraday market and the reserve markets) is covered by energy legislation. Any breach of the prohibition against market manipulation in the energy legislation may also constitute a breach of the prohibition provisions in the Competition Act. RME and the Norwegian Competition Authority therefore have semi-annual meetings where RME reviews the results of the market monitoring, and where the Norwegian Competition Authority also provides information about the cases it has been working on. The Norwegian Competition Authority enforces the Competition Act's prohibition against abuse of a dominant position and anti-competitive co-operation. The Norwegian Competition Authority is also responsible for merger control and has the possibility to stop mergers that lead to a significant restriction of competition.

The marketplaces for electricity trading (Nord Pool, EPEX) are also obliged to monitor their marketplaces and the behaviour of the participants in these markets. RME collects market participant information and other fundamental market information, and this forms the basis for RME's market monitoring. With the energy transition and changes in the market, it is very important that the overall monitoring is effective and captures market manipulation across sub-markets and borders.

When assessing whether abuse has taken place, it is common to examine the relationship between a producer's costs and prices achieved, and possibly also the relationship between costs and bids in, for example, the spot market and the balancing markets. The analytical challenge is that for hydropower producers, the most important cost is the player's own subjective assessment of the value of the water.

Since it is demanding (for outsiders) to assess the individual player's bidding, analysis methods have been developed for the power sector that focus on the players' theoretical or hypothetical opportunities to profit from abuse of market power. One such method is called the Residual Supplier Index (RSI). The aim is to calculate the extent to which a major player can count on being absolutely necessary for supply in a bidding zone, including imports, to be large enough to cover demand, including exports. If the player cannot expect to be a residual supplier very often, the practical possibility of influencing prices is relatively small. In 2019, an analysis for Statnett concluded that the opportunities for abuse were generally small, and that they would be further weakened by the new interconnectors to the UK and Germany (Bjørndalen og Hagman 2019).

7.6 Does the wholesale market work?

As the review of the electricity market and pricing mechanisms in this and the previous chapters shows, the wholesale market for electricity is a large and complicated system that must make many decisions simultaneously to ensure good security of supply and, not least, to ensure that prices reflect the underlying resource situation in the market and that costs are not higher than necessary.

The conditions for efficient price formation and efficient allocation of scarce resources are largely met in the wholesale market. The set of markets is comprehensive and designed so that relevant information will be reflected in prices. The price mechanisms are structured so that the players maximise their revenues or minimise their costs by basing their sales and purchase bids on the actual costs of production or the benefit effects of consumption. The electricity market encourages competition between players, and no single player has particularly great opportunities to influence prices in their favour.

A special feature of the Norwegian electricity market is that the option of choosing contracts with a stable electricity price in practice only seems to be available to the really large electricity customers. Among households, the proportion is very low and lower than the proportion of the population with fixed-rate mortgages. This may be related to the electricity suppliers' ability to hedge their prices in the forward market and to household demand.

An analysis conducted for the Ministry of Petroleum and Energy points to a number of reasons for the low demand for fixed price agreements from households and small and medium-sized enterprises (THEMA 2022), including the Consumer Council's recommendations for spot price contracts and the fact that the spot price has historically been low so that end users have managed the price risk themselves. Many power suppliers have cancelled fixed price contracts due to price fluctuations in the forward market over the past year. On the supply side, lack of liquidity in the EPAD market is one of the biggest challenges. Power suppliers use standardised financial products to offer fixed price agreements to end customers, see chapter 6.1.3 and 6.7.2.

There is thus little to suggest that there is any major market failure in the wholesale market. However, we cannot ignore the fact that access to information and the flow of information between the authorities in particular, including Statnett as system operator for the transmission grid, and the players could be better, especially in situations of scarcity. Analyses of the forward market and the opportunities for effective price hedging indicate that liquidity in these markets could have been greater.

Overall, this indicates a well-designed market, but with some potential for improvement.

The wholesale market for electricity has been widely criticised in recent years because the price level has been high and unpredictable, and because it can be difficult to understand why different production technologies do not deliver electricity prices that reflect the different production costs, which for example for hydropower production are lower than the average price level in the market. The price level has been perceived as unacceptably high, but the market has generally delivered prices that reflect the resource availability and water values that power producers have as a result of a very demanding energy supply situation in Europe.

The current market model is based on the marginal pricing principle, as explained in chapter 4 and 7. Whether there is an alternative to such a system, also in light of the energy transition, is discussed in chapter 14. Different types of measures that affect the price level in the wholesale market within the current model are discussed in chapter 15.

8 Price formation and competition in the retail markets

8.1 What is the retail market for electricity?

In the retail market for electricity, customers buy electricity for their own consumption. End users of electricity include both households and businesses that buy electricity via a freely chosen electricity supplier or through a broker. An electricity supplier buys electricity in the wholesale market or enters into price hedging agreements in the forward market for electricity and sells it on to end users, depending on the type of agreement they sell. Some large industrial customers also buy electricity on a power exchange themselves or directly from a power producer without going through an electricity supplier, and thus cover all or part of their needs in the wholesale market. In this report, we discuss the purchase of electricity from large industrial customers together with the retail market, since several of the issues for this customer group coincide with the rest of the retail market.

In addition to electricity suppliers and customers, the following players are important for the retail market:

- The Norwegian Energy Regulatory Authority (RME), which is the regulator and supervisory authority for the market
- The grid companies, which are responsible for the physical delivery of the electricity customers buy
- The Consumer Authority, which oversees a number of regulations relevant to this market, including the Marketing Control Act.
- Renewable Norway, Distriktsenergi and Samfunnsbedriftene Energi - interest organisations for power producers and electricity suppliers, which work with both contractual frameworks and voluntary certification of electricity suppliers
- The Consumer Council, which works with consumer rights and operates the online portal strompris.no
- The Electricity Complaints Board, which is an advisory body for disputes between customers and both grid companies and electricity suppliers
- Elhub, which carries out supplier switches and communicates settlement data (meter values) between grid companies and power suppliers

Total electricity consumption in Norway is around 133 TWh annually.[35] Approximately one-third of this consumption goes to household customers, one-third to power-intensive industry and one-third to other business and public sector customers (see figure). Although some companies in the power-intensive industry buy some of the electricity they consume directly in the wholesale market or from power producers, companies in this industry also buy electricity via electricity suppliers. The total annual electricity consumption traded via electricity suppliers is thus at least 90 TWh.

[35] Source: SSB. In 2021, gross electricity consumption was 139.5 TWh. In 2022, gross consumption fell to 133.4 TWh (these are not temperature-corrected figures, but measured values).

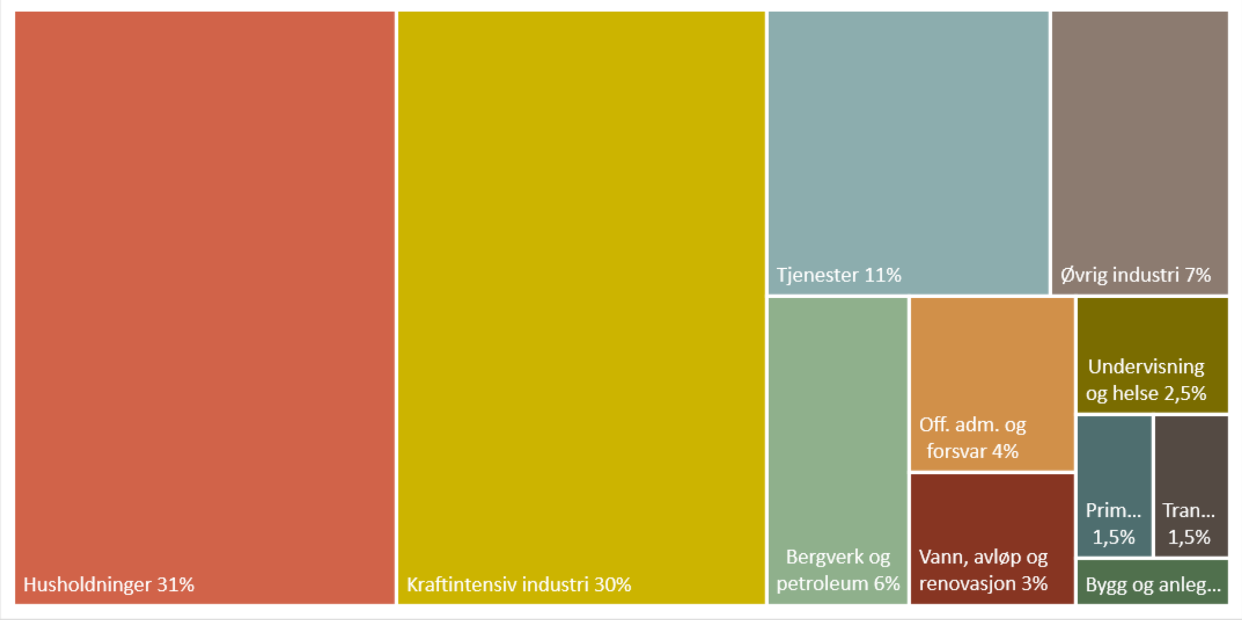

Figure 8- 1 Consumption of electricity by different customer groups (Source: SSB)

8.2 Why there is a retail market for electricity

8.2.1 What does an electricity supplier do?

The electricity suppliers in the retail market are intermediaries between the wholesale market and the future market for electricity on the one hand and the end user of electricity on the other. For the vast majority of customers, buying electricity directly in the wholesale market and/or the forward market for electricity would be far too complicated and also very expensive. Customers would then have to buy their own power consumption hour by hour the day before consumption, and be responsible for balancing. In other words, they would be responsible for balancing out their consumption if they used less or more than they had calculated they would use hour by hour during the day. This would require a great deal of time and knowledge of the electricity market, and would be an insurmountable task for most people. The market is not organised for this either.

Large power-intensive customers have extensive knowledge of the power market and relate to the purchase of electricity as a commodity. These consumers are themselves players in the wholesale market and buy power directly on the exchange and from producers. All other electricity customers (both households and small business customers) need someone to assume the risk and balance responsibility in the wholesale market, so that they do not have to deal with this market themselves.

The electricity suppliers provide this service - they purchase power in the market on behalf of their customers and sell end users an agreement that includes both the electricity price in the wholesale market (spot price), payment for the service the electricity supplier performs (notification, settlement and thus balance management) and also for the risk the supplier assumes by delivering such agreements (risk of imbalances, possibly also price, profile and volume risk for agreements with a fixed price to the customer).

If the electricity suppliers did not exist, the service they provide would have to be provided by someone else, since ordinary customers cannot do this themselves. Placing the responsibility on the power producers, for example, would in practice mean maintaining the current electricity supplier service with fewer providers.

8.2.2 Price formation in the retail market

The retail market for electricity has good opportunities for efficient and transparent pricing. Basically, all players sell the same thing - electricity is a homogenous product. The basis for the electricity price to end users is the price in the wholesale market in the case of a spot price agreement, or the price in the future market for electricity if the customer has a fixed price agreement where the price is agreed for a period in the future. In the agreement with the electricity supplier, there is often also an element that covers the electricity supplier's costs and risk of providing the service, including costs related to balance responsibility, often through a premium in øre/kWh and/or through monthly amounts that are independent of consumption. Payment for the statutory purchase of electricity certificates and VAT must be included in the surcharge.[36] Some electricity suppliers invoice neither a surcharge nor a monthly amount, but finance their operations through the sale of additional services, such as charging services, insurance and energy counselling.

In addition to the wholesale price, surcharges to the electricity supplier and the purchase of any additional services in the electricity contract, there is also grid rent, electricity tax, Enova tax and VAT.

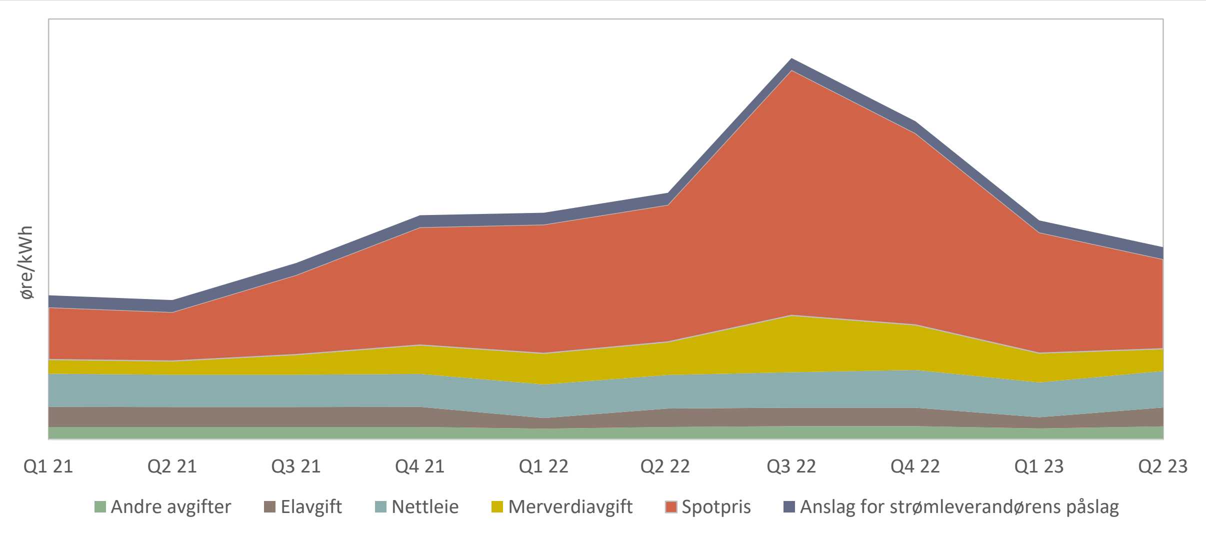

Figure 8- 2 Electricity costs are more than the electricity price (Source: SSB)

Electricity suppliers cannot compete on the purchase price of electricity. This is set in the spot market. In the future market, there is somewhat more room for competition on price, as some suppliers' hedging strategies may be better and thus more cost-effective than their competitors. However, the basic market price in the futures market is the same, so the price differences for fixed prices are rarely significant. The factors on which electricity suppliers can compete are essentially:

- Cost-effective operation of the service they provide (low mark-up)
- Assessment and pricing of the risk assumed by the electricity supplier (risk of imbalances, possibly price, profile and volume risk in fixed price agreements)
- Contract offerings - spot price agreements, fixed price agreements, to household customers and/or businesses
- Additional services
- Customer service

Although the retail market has good opportunities for competition, the fact that the players compete on the margins on top of the market price for the raw material creates a risk that suppliers may

[36] The Settlement Regulations FOR-1999-03-11-301, section 8-6.

attempt to increase their margins by creating information asymmetry and a lack of transparency. The retail market for electricity has been criticised precisely because the market is unclear and difficult to understand. For the market to function effectively and drive innovation and thus lower costs for customers, it is important that the market is framed in such a way that it is transparent and that customers can have confidence in the market.

8.3 Lower, more predictable and competitive prices in the retail market

The Committee shall assess competition conditions in the retail market and measures that can result in lower and more predictable prices in the retail market in the future. The Committee shall also assess measures for competitive prices.

Many of the challenges for end users are related to the price in the wholesale market - the market price of electricity has been very high. Although prices have fallen since the peak in the winter of 2022/23, we can expect the price level to be higher than historical levels in the future. Potential measures to reduce the price level in the wholesale market are discussed in chapter 15.

Measures in the retail market can contribute to **lower** prices in two ways:

- A more well-functioning market, with more effective competition, could reduce the mark-up for electricity suppliers that comes on top of the market price or wholesale price.
- If the authorities want to give consumers lower prices than the wholesale price level, subsidy programmes are a possibility

The retail market can contribute to more **predictable** prices through:

- A well-functioning market for price hedging allows electricity customers to choose the degree of price hedging and predictable costs

Assessing what constitutes a well-functioning market is therefore a basis for determining the possibility of measures that can contribute to lower mark-ups and better opportunities for price hedging. Chapter 17 deals with various forms of support programmes if prices to end users are to be reduced to a level below the market price.

8.4 What is a well-functioning retail market for electricity?

Electricity is a necessity for consumers. From a *consumer perspective*, a well-functioning retail market for electricity means that prices reflect the wholesale price (that they do not pay too much), that information about the product is easily accessible and that customers have good opportunities to switch contracts if they so wish, and a well-functioning retail market should also give consumers the opportunity to hedge against risk, for example through the purchase of fixed price contracts or other solutions that 'respond' to customers' potential challenges related to variations in electricity prices and energy needs.

From a *supplier perspective,* a well-functioning retail market is a market where there are low administrative barriers to establishing operations. The market should be well and clearly regulated to ensure effective competition in the market It should be easy to use the underlying market prices as a basis for deliveries and provide access to relevant price hedging in order to offer fixed price agreements.

From a *producer and market perspective,* a well-functioning retail market is a market where customers face the actual market prices for electricity. How the retail market functions can have an impact on the wholesale market, since customer demand affects the price level. Access to power is a limited resource in the short and long term, and high prices signal scarcity (and vice versa for low prices). If the prices faced by customers do not reflect the actual prices in the market, they may demand more electricity than is socially optimal, thus contributing to a higher price level in the wholesale and retail markets than would otherwise be the case.

8.4.1 Households and businesses as customers in the retail market

There are several markets where households enter into an agreement to purchase a product by subscription, such as broadband, associated content services and telephony. In addition, there are markets where purchases are agreed over time, such as insurance and loans. However, the electricity market differs from other markets that households relate to. In the electricity market, households are exposed to a commodity that is traded on an exchange where the price is set hour by hour, and prices can vary widely over both short and long time horizons. Most other products purchased by households do not have prices that vary to the same extent. In the interest rate market, however, there are continuous variations that banks and other lenders *do not pass* on to their loan customers. However, floating rate loans are not priced as the current money market rate plus a (fixed) premium, but the interest rate is adjusted when the money market rate has moved significantly.

Previously, customers in the retail market were largely invoiced according to an average price for electricity. This has changed in recent years. The roll-out of new electricity meters has made it possible to measure consumption hour by hour, and consumers are now invoiced on this basis. This gives customers better opportunities to influence their final bill. For the wholesale market, it is positive that customers are incentivised to use more electricity during periods of good supply and low prices, and less when there is a shortage. This is a significant change for consumers, who on the one hand have more information and more options for adaptation than before, but also have to change their own behaviour and/or use automation solutions to utilise the information and change their consumption in line with prices. Households' desire and ability to make these adjustments varies.

For businesses, the considerations regarding electricity purchases will be somewhat different, as electricity costs are part of a company's operating costs and companies have different opportunities to adapt to changing costs over time. At the same time, different types of companies relate to the market in different ways. For power-intensive industry, electricity is a key input factor in production, and large players actively relate to the market and have strategies for (long-term) price hedging and an active relationship with spot price exposure. This type of company is therefore generally not dependent on the retail market. Companies that operate forms of commodity-based production are often exposed to similar price risk in other markets and are able to assess risk in the electricity market and assess their own need for price hedging. They also often enter into price hedging agreements through electricity suppliers. However, other businesses, for example in service industries, and also small and medium-sized enterprises in general where electricity has traditionally not represented a significant cost and risk, may be more similar to households in their approach to electricity costs. A number of these businesses will have little expertise and few resources to assess the electricity market and hedging strategies.

8.4.2 A well-functioning retail market for electricity will become more important in the future

In chapter 12 we explain why the Committee's analyses assume that electricity prices in the future will probably be at a higher level and with greater variation within the day, week and year than we have seen in recent decades. These changes in the wholesale market mean that a well-functioning retail market is becoming increasingly important.

From a consumer perspective, it is important that competition in the retail market is as effective as possible, so that the surcharges on top of wholesale prices are as low as possible, and that consumers have access to electricity contracts that allow them to hedge against price fluctuations.

For example, fixed price agreements or other agreements that provide a greater degree of predictability.

A prerequisite for effective price formation is active customers who, by making conscious choices in the market, contribute to effective competition and incentivise the development of new products. We cannot expect all customers to be equally conscious of the choices they make. The retail market for electricity, like all other markets, has passive customers who rarely or never consider the type of contract they have. This does not necessarily mean a loss of efficiency for the economy as long as the proportion of passive customers is not too high.

Given that the market is otherwise well-functioning, and there are a limited number of contract types to choose from in practice, it is not certain that the risk of being a passive customer is particularly high. Greater fluctuations in electricity prices in the future will mean that the value of shifting consumption from periods of high prices to periods of low prices will increase and the cost of not engaging with the market will therefore increase. Greater fluctuations in the price of electricity will also mean that the financial significance of the choice between contracts with fully or partially fixed prices will increase. It is therefore important that the framework conditions do not unnecessarily restrict electricity suppliers' ability to offer relevant agreements and services.

For energy resources to be utilised in the best possible way, it is becoming increasingly important that customers adapt to the price signals in the market. This is important both to ensure the lowest possible prices over time - if customers reduce consumption during high-price periods of scarcity, this will mean lower prices in the wholesale market than we would otherwise have seen - and to stimulate new solutions for storage and flexibility in the market. Such solutions become profitable by adapting to price fluctuations, thus helping to smooth out prices in the longer term.

One of the most important topics for the future development of the retail market is therefore how it should handle both consumers' need for stable and predictable prices, while at the same time safeguarding society's need for a sufficient number of customers to react to and adapt to the price signals in the wholesale market. These may be considerations that pull in opposite directions.

8.5 Competition in the retail market

There are currently around 120 electricity suppliers in the Norwegian market. Many electricity suppliers sell contracts to both households and businesses. Some sell only to the business market, others only to the household market. Some sell throughout the country, while others only sell contracts within a bidding area or within specific municipalities.

NVE's statistics on the retail market[37] show that there are around 6-700,000 supplier changes per year in the retail market. Supplier switching is clearly highest in the winter months. 2021 and 2022 both had a high number of switches towards the end of the year, when prices rose sharply. The switching rate - the proportion of customers who switch supplier - has in recent years been around 20-25 per cent for household customers and 10-12 per cent for business customers. The figures for 2021 and 2022 do not stand out in these statistics. So far in 2023, the number of switches has been below the level of previous years.

[37] https://www.nve.no/reguleringsmyndigheten/publikasjoner-og-data/statistikk/statistikk-over-sluttbrukermarkedet/

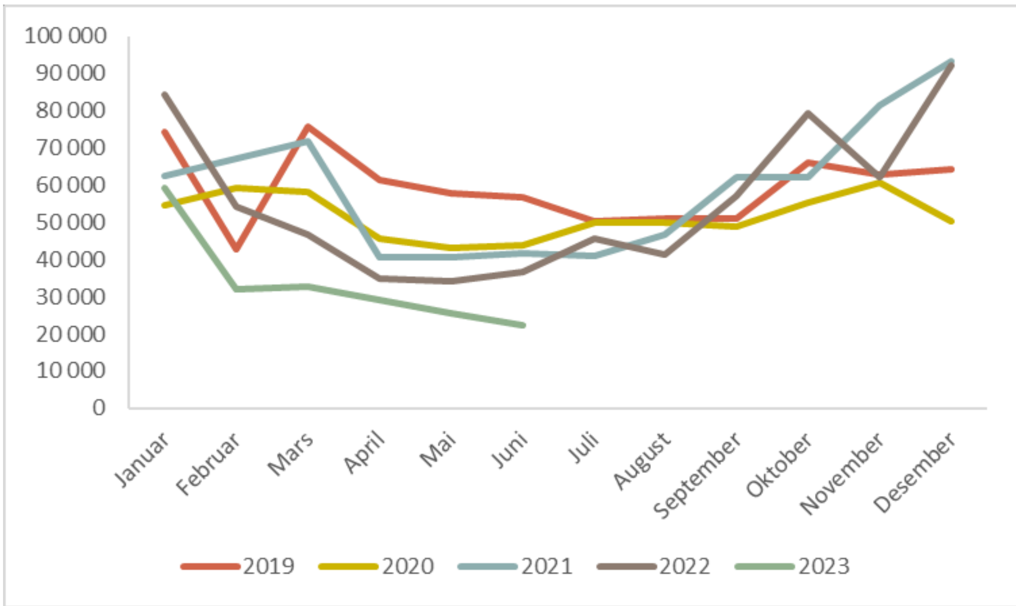

Figure 8- 3 Supplier changes per month (Source: NVE)

Despite many changes of supplier, the market shares of the largest suppliers in the various bidding areas have remained consistently high in recent years. The market shares of the largest and second largest suppliers are very different, both in the household segment and among business customers. The retail market is characterised by a few really large suppliers and many small suppliers. This is particularly true for business customers, where the market share for the five largest players for several of the bidding areas is up to or equal to 100 per cent.

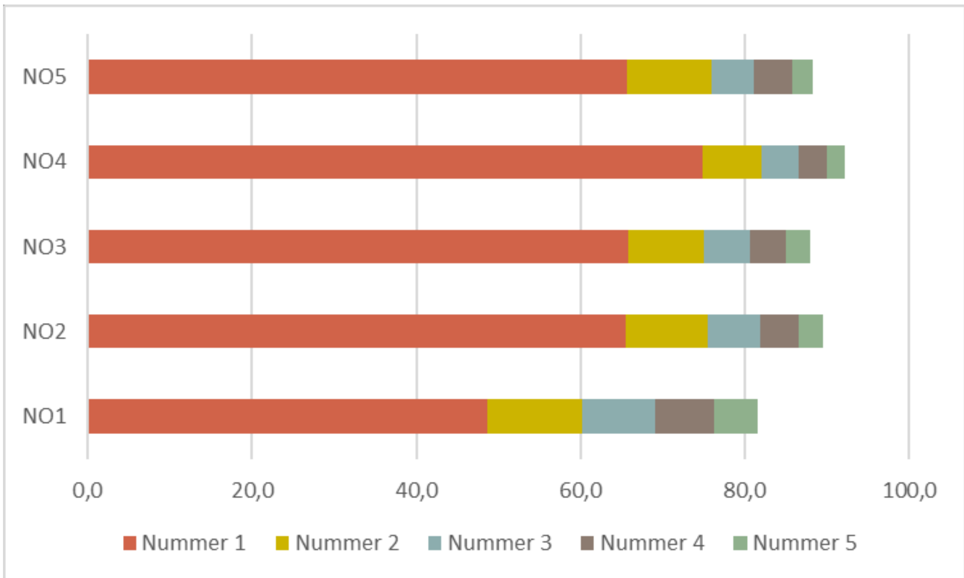

Figure 8- 4 Market shares for the largest suppliers, household market (Source: NVE)

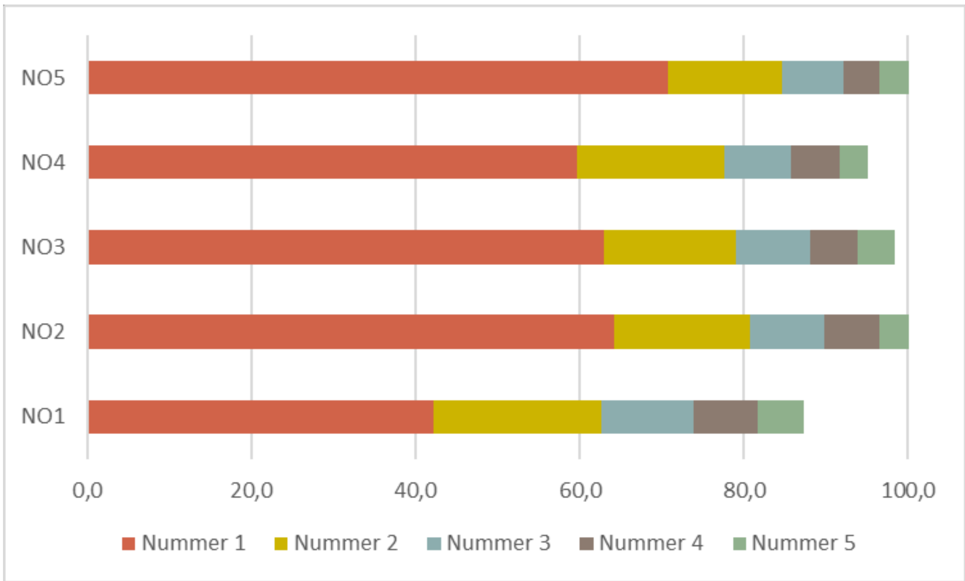

Figure 8- 5 Market shares for the largest suppliers, business market (Source: NVE)

In order to shed light on competition in the retail market, the Committee has analysed what we can call a simplified gross margin for electricity suppliers. This is not the same as profit or surplus, but can be understood as gross sales revenue less a simplified estimate of the costs of purchasing power. The simplified gross margin is intended to cover the electricity supplier's costs related to balance responsibility, the operation of the business (salaries, trading costs, etc.) and capital costs.

The analysis is based on figures that RME collects annually from all companies with a sales licence. The committee has been given access to data on sales revenues and volumes by customer group and region for the years 2018 to 2021. Sales revenues must be understood as the total amount customers pay, less public taxes - in other words, the electricity price in accordance with the agreement with the customer, including surcharges and any additional services. Sales revenue is divided by volume, resulting in an average retail price per company, customer group and region. The simplified gross margin for each company is calculated as the average retail price less the average spot price in the region. We have then expressed the relative gross margin as a proportion of the retail price.

The sample has been given access to data for the years 2018 to 2021, and has calculated the average relative gross margin per year for each customer group and region. Based on this, we have defined normalised gross margin as each company's relative gross margin as a proportion of the average. An electricity supplier with a gross margin equal to the average will then have a normalised gross margin equal to 1.

Before plotting the results in the figure below, we have removed the largest and smallest companies.

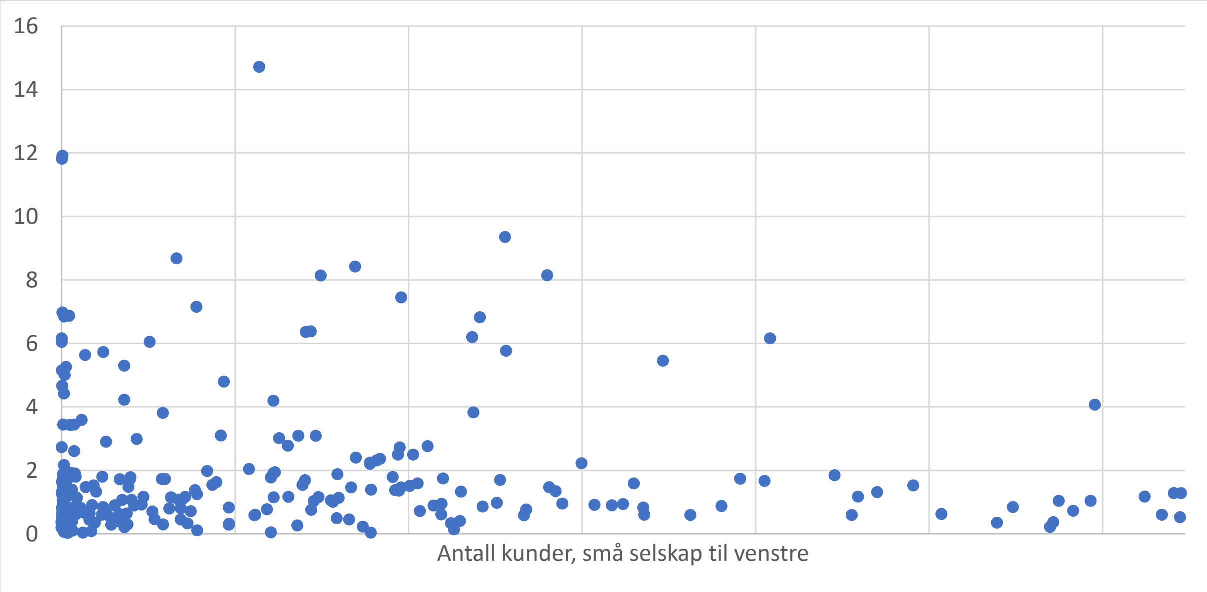

Figure 8- Normalised gross margin, sample of Norwegian electricity suppliers (Source: Strømprisutvalget, data from RME)

It is worth noting some sources of error in the data before we take a closer look at what the analysis tells us. It is likely that sales revenue includes payment for additional services, such as charging an electric car, insurance or access to specific apps. Some of the sales revenue almost certainly comes from fixed price agreements. As we compare sales revenue with spot prices, sales revenue from such agreements should have been deducted. In isolation, the lack of correction for fixed price agreements may mean that the variation is underestimated. Taken together, these sources of error may mean that the variation in normalised gross margin may in reality be less than Figure 8- shows.

The analysis indicates that the gross margin decreases with the size of the supplier, but even among those that are not particularly small, there are companies with significantly higher gross margins than the average. Many companies are just above and below the average gross margin. This indicates that there is a high level of competition in the market, and that customers with expensive contracts have many opportunities to switch to a cheaper contract. At the same time, there are still some suppliers with significantly higher gross margins than the average, which can be interpreted as an indication that some customers have relatively expensive contracts. There may be several reasons for this, which we discuss in more detail in the discussion of market failure below.

8.6 Agreements in the retail market for electricity

There are several different types of agreements you can enter into for your electricity consumption. The main difference is related to the actual price of electricity and the conditions for changing the price:

- Spot price agreement - the electricity price shall (in accordance with the settlement regulations[38]) be the spot price in the customer's bidding area hour by hour
- Fixed price agreement - the electricity price is fixed (cannot be changed) per kWh for the entire consumption for an agreed period
- Variable price agreement (often called standard variable) - the supplier sets a price that is fixed for the time being, but can be changed with at least 30 days' notice, for example based on spot price developments

[38] FOR-1999-03-11-301, Regulations on metering, settlement, invoicing of grid services and electrical energy, grid company neutrality, etc.

A variable price provides more predictability than a spot price agreement, while the agreement follows market developments. The name 'standard variable' is related to the fact that before we had hourly metering of households, this was about as close to the actual hourly prices as it was meaningful to agree. The type of agreement at the time was a standard agreement unless otherwise agreed. Until recently, the price could be changed with 14 days' notice, but this has now been changed to 30 days' notice. A significant challenge for electricity suppliers is that it is difficult to find effective risk mitigation in the future market for an ongoing 30-day period. Several players must therefore calculate the risk premium themselves, which they must incorporate into the electricity price. These agreements have been criticised for being difficult to understand, not providing sufficient price hedging and resulting in a higher cost than the spot price over time. The Consumer Council has advised against this type of agreement. The industry itself emphasises that the aim of the agreements is not to beat the spot price, but to provide a form of short-term price hedging. However, since the introduction of the 30-day notification requirement, the complexity and risk of the product has increased for electricity suppliers, and the supply of such agreements has largely ceased.

Since spot price agreements follow the wholesale market price, it is normally assumed that such an agreement results in the lowest overall cost over time.

A fixed price agreement means that the price for a period of time ahead is set equal to a price expectation plus a risk premium from the supplier, as explained in chapter 6.7.1. The price expectations will be based on the future market for electricity, which the electricity suppliers must trade in to be able to secure the purchase of power at a given price in the future. Although the fixed price is based on a price expectation, the market will not develop exactly in line with this expectation. The fixed price will therefore be different from the current market price - it may be higher or lower in certain periods. You cannot expect to be able to "beat" the market and the spot price with such an agreement, but it is also not a given that the fixed price will be more expensive than the spot price. Most people who choose fixed price agreements emphasise that it provides predictability in return for paying some form of insurance premium. Customers must therefore weigh the need for a fixed and predictable price against the possibility of having periods where the fixed price is higher than the current market price.

For fixed price agreements of this type (fixed price for the entire consumption), the suppliers' biggest challenge is that the customer's consumption is not constant over the day and that there are thus different volumes in the different hours, while the agreements they can use to hedge prices in the future market have the same volume in all hours. This profile risk, which also applies to agreements with variable prices, is therefore not possible to hedge in the future market . Suppliers must price this risk into their contracts.

The Consumer Council has traditionally explained that spot prices are the cheapest over time and has recommended this to customers. The Consumer Council now emphasises that spot price agreements have historically been the best option, but points out that price developments in recent years have been surprising and that it is difficult to assess future developments, and that if you want to insure yourself against fluctuations and future price peaks, a fixed price may be a good alternative.[39]

One barrier to entering into fixed price agreements is that it is a more difficult market for a consumer to understand. With a spot price agreement, the customer knows that the price will be based on the current market price. When entering into a fixed price agreement, however, the price level will depend on long-term price expectations. In theory, customers can compare the contract price with

[39] https://www.forbrukerradet.no/forside/bolig/strom/sjekkliste-for-du-velger-stromavtale/

prices in the future market at the time the contract is entered into, but for household customers and a number of business customers, this information will not be readily available. The profile risk also means that the comparison is not very precise, even if the customer has an overview of the future market. There is therefore greater information asymmetry when entering into a fixed price agreement than with a spot price agreement. This makes it all the more important that customers can compare the price level in the same type of agreement from different suppliers.

8.6.1 Electricity contracts for household customers

For household customers, spot price contracts have been, and continue to be, the dominant alternative. The statistics show that the proportion of customers with spot price contracts has increased over the past year, particularly at the expense of variable price contracts.

Although there is a supply of fixed-price contracts, demand for these contracts has been low for a long time. Only a very small proportion of households have had a fixed price contract. This differs from other countries. According to THEMA (2022) there is much higher demand for fixed-price contracts in Sweden and Finland. The share of fixed-price agreements for households in Sweden was just over 25 per cent in June 2022, while the share for Norwegian households was around 5 per cent. Few Norwegian households have also entered into new fixed-price contracts after the price increase. Chapter 8.7 describes the decline in the supply of fixed-price contracts from the summer of 2022.

A variant of the use of price hedging in the household market is agreements where you pay the current spot price, but the supplier smoothes out the payment over the year and sets a monthly amount based on expected consumption and price trends. The amount is adjusted when the price level in the market changes significantly. The customer will then have a balance for electricity costs that is plus or minus in the agreement, typically paying more in the summer than what consumption actually costs, while paying correspondingly less in the winter. RME has criticised this type of agreement for obscuring the actual price and for functioning in practice as a consumer loan. In addition, RME has pointed out that most of these agreements have been in violation of section 7-1 b of the Settlement Regulations, which requires that electricity invoices must be based on regular readings of consumers' electricity meters, and that advance invoicing of electricity is limited to 10 weeks in advance. RME has therefore decided that a number of suppliers will discontinue the offer.

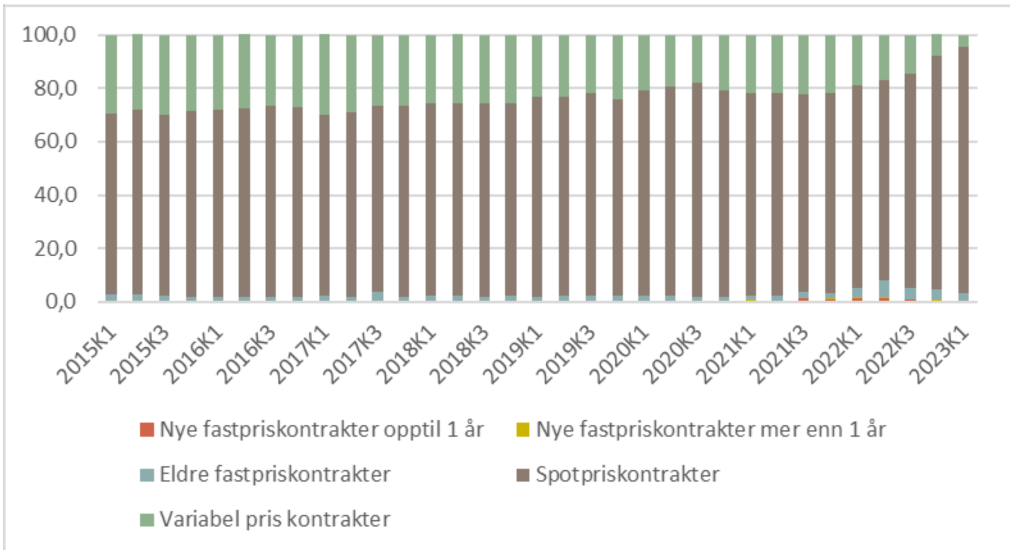

Figure 8- 7 Contract types in the household market (Source: NVE)

8.6.2 Electricity agreements for the business, voluntary and municipal sectors

For ordinary non-household customers - businesses, the voluntary and municipal sectors - the same contract types are used as for households: spot price, fixed price and variable price. However, in this segment it is also common to have an electricity contract that combines spot price and fixed price, known as management products. These provide price hedging for part of the volume purchased by the customer, normally 70 per cent of the volume, while the remaining part of the purchase is made at spot price. The statistical basis in this field is inadequate. In Statistics Norway's statistics on electricity contracts for businesses, management products are registered as spot price contracts, even though they may contain large elements of fixed price. However, Statistics Norway's statistics show the proportion of businesses, excluding power-intensive industry, that currently have fixed-price contracts with 100 per cent hedging. Based on the statistics, we can see that the proportion of contracts with variable prices has also fallen in the business sector.

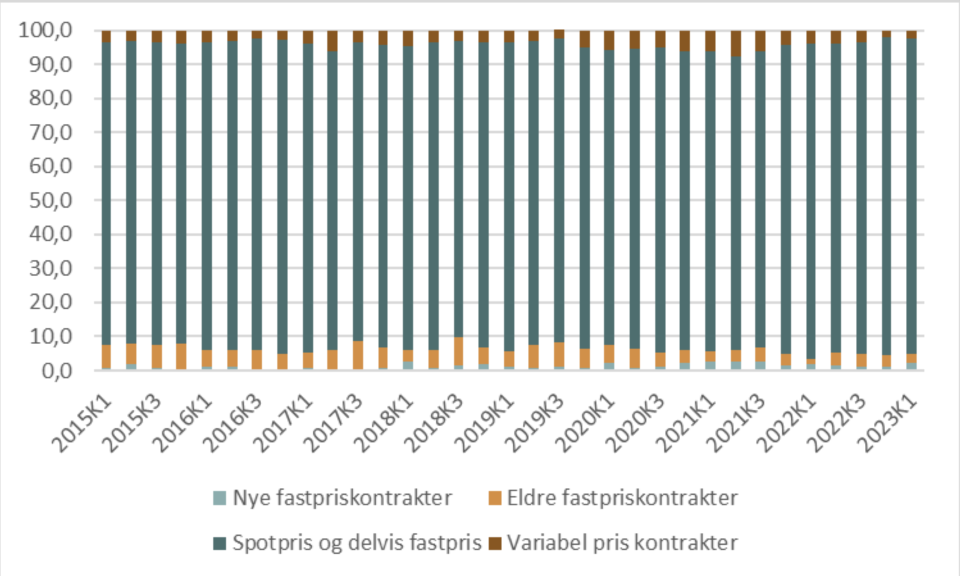

Figure 8- 8 Types of contracts to business and other organisations, excluding power-intensive industry (Source: Statistics Norway)

Renewable Norway has asked major players in the business market how widespread price hedging is among business customers. The suppliers state that price hedging in the business market has been widespread for a long time, and several major electricity suppliers state that as much as 50 to 70 per cent of their business customers have some form of price hedging. One company has reported significantly lower figures than this.

However, the volume that is price hedged is lower than 50 to 70 per cent of the suppliers' portfolio, as this is largely price hedging in the form of management products where not the entire volume is price hedged. Typically, the degree of hedging in the "delivery year" is higher than for future years. The time horizon of the management products varies, but the companies report a time horizon that varies from 6 months to 5 years.

Some business customers have chosen not to hedge their electricity consumption. It is not possible to say anything industry-specific about who has chosen not to have price hedging, but in general there are customers with low consumption where the cost of electricity has not been a decisive factor for the company. There are also some large customers who have relied on a pure spot price agreement. For these customers, the cost of electricity in 2022 naturally increased significantly.

Some electricity suppliers are registering increased interest in price hedging in 2023, but point out that fewer such agreements have been entered into during the high price period. Suppliers point out that high price periods are generally a demanding time for price hedging, since even very long-term prices in the future are characterised by the high price level in the short and medium term. If business customers have sufficient room for manoeuvre, they often choose to hedge prices during periods when prices are perceived as favourable.

8.6.3 Price protection for large electricity consumers

Several large consumers in power-intensive industry enter into bilateral power purchase agreements directly with power producers. At least 90 per cent of the power consumption of this type of industry is covered by long-term agreements (Norsk Industri 2022). The companies may also have part of their consumption in the spot market.

Long-term power contracts vary in duration, with some contracts having a purchase period of 20 years. There are no public statistics on these agreements.

The authorities have facilitated this type of agreement through exemptions from resource rent taxation for power producers when entering into long-term power agreements of 7 years or more, chapter 8.6.4.

The agreements provide power producers with a secure income over time, while customers who consume large volumes of electricity are ensured predictability about one of their most important operating costs.

When negotiating a bilateral agreement over many years, there is little reference price in the financial markets, which have the greatest liquidity over the next two to three years. As with fixed price agreements in general, the price level in the agreements is based on the expected development in future spot prices and the degree of risk aversion, but to a greater extent a long-term price expectation than the future market. Higher price levels and increased unpredictability in the power market also lead to higher prices when entering into long-term power contracts.

8.6.4 Facilitation of long-term price hedging - contract exemption for resource rent tax and ECSC guarantee programme

Base rent tax

Resource rent can be understood as excess returns over and above normal returns and is typically linked to the use of limited natural resources. Taxation of resource rent will, if the tax is appropriately designed, not lead to tax-motivated adjustments among the players. Because the tax burden is higher for activities that are subject to resource rent tax than other activities, standardised prices are used when determining resource rent tax. Without the use of standardised prices, the taxpayer could have avoided resource rent tax, for example by selling to its own company at a price that does not generate a profit.

As a general rule, the spot price of power is used when calculating the resource rent tax for hydropower. Additional or reduced revenues from fixed price agreements or other price hedging will not be included in the resource rent tax. One effect of setting the norm price at the spot price is that a power producer who wants security for future revenues after tax must take the resource rent tax into account and *not* price hedge the part of the production that the resource rent tax represents. With the current resource rent tax rate, a producer can achieve a future income after tax that is independent of the spot price by hedging 42.3 per cent of production. [40]

[40] In addition to price risk, producers also face volume risk. If they knew exactly how much production they would have in the coming years, they could hedge 42.3 per cent of this volume and not worry about the spot price in the short term. The challenge of volume risk is independent of the resource rent tax. We can imagine

There are currently some exceptions to this rule. Two of the exceptions relate to long-term contracts with industry and business. These ensure that there is a match between sales income and taxable income for all power sales covered by these contract exceptions. Without the exemptions, the sale of such contracts could have resulted in a tax risk for the seller, which could have made the contracts more expensive. To counteract this, power producers are taxed at the actual price in contracts covered by the exemption.

Among other things, the exceptions solve challenges related to the fact that business demand for hedging is sporadic and that liquidity in the forward market is not particularly good. If producers have already hedged the desired volume when customers request hedging, producers may hedge more than the tax-neutral volume and thus incur a tax risk. Alternatively, offers of price hedging must be based on illiquid future contracts for area prices. With the exceptions, offers to companies can be based on the producers' own production, without tax risk.

The first exception is for the sale of power on long-term contracts to power-intensive industry. This applies to agreements entered into with power-intensive industry where the agreement period is at least 7 years and the total volume in the agreement is at least 150 GWh. Power-intensive industry is defined as production of chemical products, pharmaceutical industry, metal production and production of electrical equipment. In June 2023, the government submitted a proposal for consultation to reduce the duration requirement to three years, and proposed such a change in connection with the national budget for 2024.

On 1 January 2023, a similar exemption for taxation at contract price was temporarily introduced for fixed-price contracts for businesses, where the contracts are for a fixed (agreed) volume and with a contract duration of either 3, 5 or 7 years. The exemption means that the resource rent tax for such agreements is based on the fixed price, and not the spot market price, which is the main rule. Until now, power producers have sold such agreements through an electricity supplier, but the regulations also allow for sales directly from the producer. In principle, companies can obtain a fixed-price contract through an electricity supplier without the supplier having any tax risk priced into the contract. However, for long-term contracts, there may be limitations in the ordinary fixed-price contract market that make buying directly from the producers an alternative. However, most ordinary companies will not be able to enter into a bilateral negotiation with a power producer. The basic rent tax exemption for fixed price agreements therefore facilitates price hedging through purchases from power producers, both through the power producers offering such agreements that all types of companies can purchase, and also by creating a more open market that customers can relate to.

The new fixed price market is in development. As of April 2023, 370 companies had entered into fixed price agreements within this framework, which is a small proportion of the companies that must be considered relevant for entering into such a fixed price agreement. The agreements have been criticised for requiring companies to purchase a fixed volume hour by hour throughout the day, and to sell/purchase power in the spot market in the event of under/over consumption compared with the agreement. This means that the companies are exposed to fluctuations in the spot price even within the fixed price agreement. This may have had an impact on demand. In addition, the

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two producers with exactly the same expected production; 1,000 GWh. One wants to avoid exposure to the spot price for the entire expected volume, and must then sell fixed price agreements corresponding to 423 GWh. The rest must be sold in the spot market to minimise the tax risk. The other producer wants exposure to the spot price for half of the expected production, and sells 211.5 GWh on fixed-price contracts. This corresponds to 42.3 per cent of 500. If actual production ends up at 1,000 GWh, both will have received exactly the spot price exposure they wanted. If actual production is lower or higher than expected, both will have the same relative exposure to the spot price.

price level has been high throughout the winter, and some electricity customers may then wish to wait to enter into fixed price agreements until the price level is considered more normal, cf. above, in addition to the fact that a number of companies have already entered into other forms of price hedging agreements.

In May, however, the first agreements from Statkraft and Skagerrak Energi were launched with customised profiles for companies, whereby power can be purchased with the majority of the volume when the company is producing. The offer is so far limited, and it is unclear when more players will start offering similar products.

ECSC guarantee scheme

Export Financing Norway (EKSFIN) administers a guarantee programme aimed at Norwegian industrial companies with a high demand for power. Under the scheme, companies can purchase guarantees for the fulfilment of terms in power contracts. The purpose of the scheme is to make it easier for industrial companies to enter into long-term contracts. EKSFIN can provide guarantees both to the power seller, who is secured against the buyer's failure to fulfil the power contract, and to banks or other lenders, securing claims for repayment of loans the buyer has taken out to enter into the contract. The companies purchase the guarantees from EKSFIN on ordinary commercial terms.

The categories of industries that can take advantage of the scheme overlap with the industries in the resource rent tax exemption, but not completely: the guarantee scheme is aimed at companies in the timber and wood products, wood processing, chemical products and metals sectors. The companies must have an annual power consumption of at least 10 GWh and the power agreement must have a total volume of at least 35 GWh.

8.7 Is there a market failure in the retail market for electricity?

A well-functioning market provides cost-effective solutions and efficient use of resources. In theory, this can be achieved through perfect competition. Real markets rarely offer perfect competition - in practice, one or more of the theoretical conditions for perfect competition are usually not met. This is generally referred to as market failure. Market failure means that prices in the market do not fully reflect the underlying costs and customers' willingness to pay.

A report on the Norwegian retail market points out that the retail market for electricity has a number of characteristics that facilitate well-functioning price competition; homogeneous (uniform) products, many providers, low barriers to entry, in addition to the fact that switching costs for consumers are almost non-existent (Oslo Economics 2021). This would indicate that the prices of the various providers cover the costs of the most efficient suppliers, but nothing more.

In practice, however, this is not the case. The retail market for electricity has been criticised for making it difficult for consumers to compare information about different contracts, and that some suppliers have made very good profits by selling contracts that customers do not understand the consequences of.

8.7.1 Market failure from the supplier side

In 2021, the European Commission commissioned a report on the retail markets for energy in Europe, which examines the extent to which suppliers face barriers to entry in various retail markets for gas and electricity (Lewis, et al. 2021). According to the report, the five most important barriers are i) vertically integrated market players, ii) low consumer awareness and interest, iii) uncertainty about the development of digitalisation, iv) uncertainty about regulatory framework conditions and their future development, and v) finally, the strategic behaviour of market players. For electricity, the Norwegian market scores very well on the "barrier index", see Figure 8-. The report emphasises that common to the countries that come out best is that there is no regulation of retail prices and that the process for obtaining permission to become a player in the market is relatively unbureaucratic.

The report also emphasises that the Norwegian retail market is generally well-functioning, with many suppliers, a high switching rate for contracts and a proactive regulator (RME). It also emphasises that the Norwegian market is considered one of the most developed and efficient in Europe, and that retail prices are both dynamic and to a very large extent reflect the underlying market price. While it is considered an attractive market for new establishments, it is pointed out that relatively few new providers, and especially operators established outside Norway, are gaining a foothold as suppliers in the retail market.

Lewis, et al. (2021) identify two significant barriers for providers in the Norwegian retail market for electricity:

- *Strategic behaviour in the market*: Although the Norwegian retail market has many suppliers, there are also many areas that are dominated by a local supplier that has been integrated with the local grid company - this while grid companies have often also provided other services, such as charging infrastructure for electric vehicles. However, the report emphasises that this barrier was largely resolved with the new regulations on corporate and functional separation for grid companies that came into force in 2021[41] . However, as of 1 July 2023, grid companies with fewer than 100,000 customers are exempt from the functional separation requirement. In practice, these changes have therefore been reversed for most grid companies. However, RME still requires a separate name for the grid company. The report also points out that the fact that the local grid company and local electricity supplier are part of the same group may reduce customer confidence in other electricity suppliers in the same area.
- *Uncertainty around digitalisation and new technology*: Changes on the technology side of the electricity markets require the regulatory framework for the market to change in line with developments. A perception of late follow-up from the authorities leads to uncertainty for suppliers regarding the development of services and products. The report emphasises that the Norwegian regulatory process is relatively stable, but also states that setting a timetable for the development of regulations can counteract the uncertainty of market participants.

[41] https://www.nve.no/reguleringsmyndigheten/regulering/nettvirksomhet/selskapsmessig-og-funksjonelt-skille/

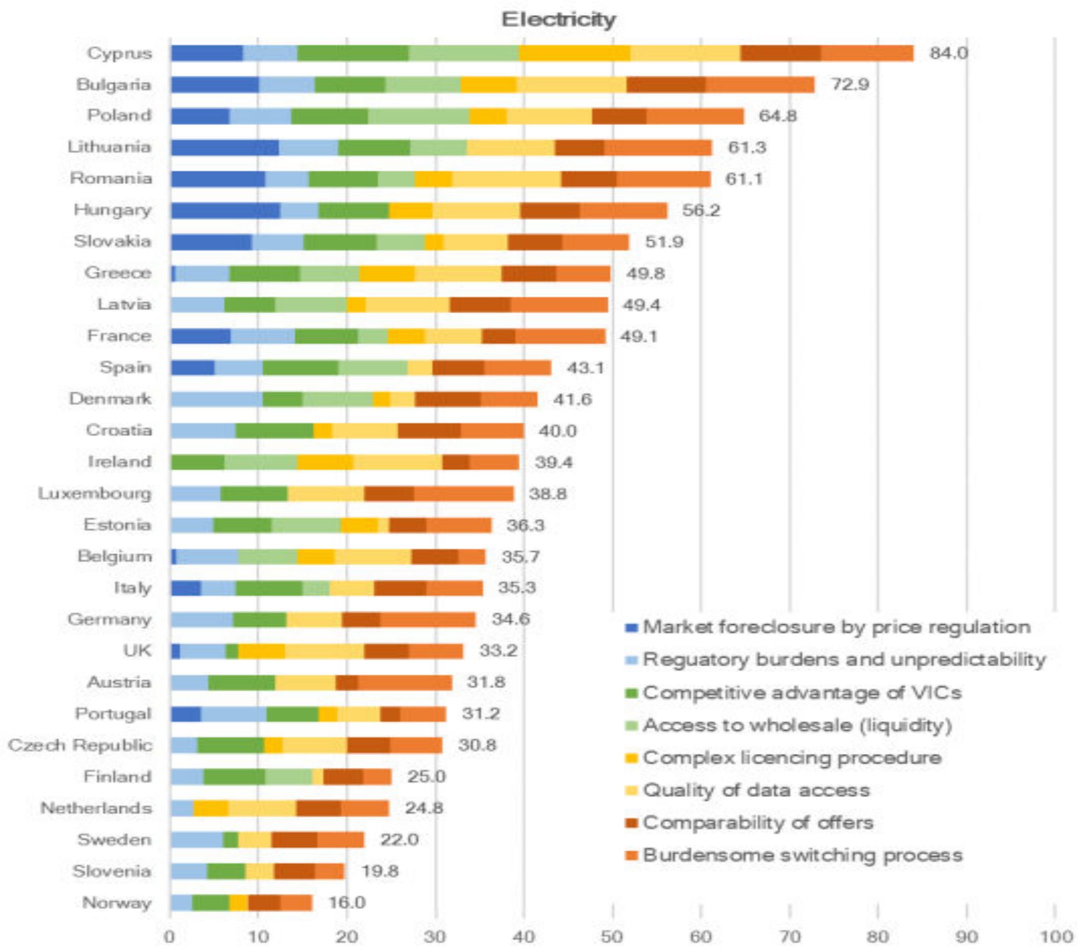

Figure 8- Barriers to entry for electricity suppliers (Source: Lewis, et al (2021))

Overall, it appears that there is a low degree of market failure for suppliers in the market. The fact that individual players have a high market share is not necessarily a market failure. Size can be the result of customers making conscious choices to use certain suppliers, for example because they are the best in terms of contract offerings, services and customer service. However, if there is a form of "path dependency" in the choice of electricity supplier, this can lead to market failure in the form of customers rejecting alternatives that would have been better, making it more difficult for new players to establish themselves in the market. There is already a requirement that grid companies that are affiliated with a company that supplies electricity must have their own name and logo, but there may be room for more information measures about electricity agreements to make alternatives visible.

8.7.2 Market failure for consumer customisation

The retail market for electricity has been criticised by consumers. In January 2023, the Consumer Council stated that the number of enquiries they received about electricity increased by 70 per cent in 2022, and that the number of complaints about electricity to the Norwegian Electricity Complaints Board doubled to over 1,200. The Consumer Council believes that it is difficult for customers to understand the agreements in the market. In a 2022 survey, 40 per cent of consumers stated that they had felt cheated one or more times when buying electricity (Forbrukerrådet 2022).

SIFO's review shows that 21 per cent of respondents do not know what kind of electricity contract they have (Tangeland, et al. 2022). At the same time, 33 per cent state that they have switched electricity contracts in the past year, and that the main reason for switching is to compare contracts on a price comparison website. 50 per cent also state that it is very or fairly easy to understand the information in their electricity bill.

The overall information problem in the retail market for electricity appears to be relatively prominent compared with other subscription markets, especially in terms of the extent of changes in contract terms and the practice of notifying these changes (Oslo Economics 2021). However, since the study was conducted, various measures have been taken to improve access to information for consumers. The report identifies the following main challenges for consumers:

- Limited interest and awareness of the product and price.
- Difficult to orientate yourself among many electricity suppliers and contract types
- Challenging to compare prices and contract terms, due to different price elements, additional services variants of the same contract type
- Difficult for the customer to predict prices and terms in the longer term and thus challenging to find an agreement that is good over time, partly because contract terms can change shortly after signing the agreement
- Difficult to recognise (register and respond to) changes in contract terms
- Deals are often sold in channels that give the customer limited information at the time of purchase, such as telesales and stands
- The public price comparison service has not worked optimally

Oslo Economics (2021) points out that information problems for customers can lead to high marketing costs for providers. This can push up prices, and it can be difficult for customers to orientate themselves in the various agreements in the market. The report generally recommends the following measures to improve the market:

- Clarification of current regulations to reduce uncertainty and room for interpretation
- Strengthened enforcement and sanctioning to reduce operators' incentives to engage in illegal trading practices
- Better information for customers

Since the report was published, several measures have been taken to rectify these issues:

- With changes to the Price Information Regulations (2022) came, among other things:
  - requirements for description of agreements in marketing - such as type of agreement, mandatory price elements, calculation method for spot price, duration, additional services, etc.
  - price list requirements - prices and terms for all contracts offered by the electricity supplier
  - requirements for notification of changes to or cancellation of electricity contracts - price (not spot price) and other price elements
- Amendments to the Settlement Regulations (2022) introduced requirements for how information on the electricity invoice is presented, with specification of all products and price elements, as well as information about the agreement and the duration of the agreement

The industry organisations Renewable Norway and Distrikts Energi have also initiated the *Trygg strømhandel* certification scheme, which sets quality requirements for electricity suppliers and can thus help customers when choosing an electricity supplier. The scheme contains requirements relating to sales activities, salespeople's expertise, product production, labelling of promotional offers, transparency of price elements, etc. The requirements generally go further than the public law requirements for electricity suppliers. The certification is carried out by DNV.

However, the need for tightening the market does not appear to have disappeared with these measures. Electricity suppliers rank high in the statistics on enquiries and complaints to the consumer authorities, and examples are constantly emerging of customers who have purchased or been billed for additional services they do not need or customers who have not understood the terms and conditions of the electricity contract. In March 2023, the Consumer Authority conducted an inspection of the practices of the largest suppliers in relation to the rules on consumer protection and price information. The inspection revealed offences at all of the 20 largest electricity suppliers. In September 2023, the government announced that during the autumn it will issue consultation proposals for legislative and regulatory changes to contribute to a more consumer-friendly electricity market. The measures will reduce information bias and make it easier for consumers to orientate themselves in the electricity market. The Minister of Petroleum and Energy has also announced that work is underway on measures for sanctions against electricity suppliers, following a proposal from RME.

8.8 The market for fixed price agreements and price hedging

Normally, fixed price agreements are offered in the Norwegian retail market for electricity, both to businesses and households. An analysis published in June 2022 shows that most major electricity suppliers in Norway, Sweden and Finland offer some form of fixed price agreement (THEMA 2022). The range of agreements varies in terms of contract length, but most offer one-, two- and three-year contracts.

However, in the summer of 2022, there was an abrupt decline in the supply of fixed-price agreements in the Norwegian market. A number of suppliers considered the risk in the wholesale market to be so high that they would not offer such agreements for the time being.

8.8.1 The relationship between fixed price agreements and the futures market

When selling fixed-price contracts, electricity suppliers will normally ensure that they make purchases in the future market (see chapter 6.7) that corresponds to the volume they agree with their customers. The electricity suppliers' reference price for fixed price agreements is therefore the price in the future market for electricity. In this way, they can minimise price risk, but they will still be exposed to volume and profile risk, cf. the explanation in chapter 8.2.

Traditionally, electricity suppliers have price-hedged deliveries based on the system price for the Nordic market, because the difference between the system price and the prices in the different bidding areas was low. The so-called area risk was considered low and priced into the fixed price offers that were made. In recent years, however, large price differences have arisen between the system price and some of the bidding areas, including in southern parts of Norway. Since liquidity and the ability to trade in the EPAD market to hedge area risk is low, several electricity suppliers have discontinued offering fixed price agreements.

8.8.2 Market barriers for suppliers

In the household market, fixed price agreements are unusual, cf. chapter 8.6.1. In the business sector, price hedging is more widespread, cf. section 8.6.2. It appears that the historically low use of fixed-price contracts in households is a result of a lack of demand, not a lack of supply. However, the increasing price variation over time and differences in area prices in recent years have led to limitations on the supply side as well.

In a report to RME on price hedging opportunities outside exchange trading, the main challenges related to price hedging are summarised as follows (THEMA 2023):

- Weaker correlation between system price and prices in the different bidding areas

- More volatile prices within bidding zones, and thus increasing collateralisation costs in the futures market
- Changes in the tax system for electricity production, which in turn affects producers' price hedging strategies and the supply of future contracts

THEMA (2022) recommends several measures to improve the situation from the suppliers' side, both related to the design of fixed price agreements and framework conditions for demand, but also to a large extent improvements in the future market:

- Gather a number of customers to sign fixed price agreements with an electricity supplier at the same time, allowing the electricity supplier to price-secure a larger volume at the same time
- More use of fixed price agreements with fixed volume, not variable volume that involves volume risk, through better information to consumers and the development of a new insurance product against price risk
- Improve liquidity in the EPAD market by connecting the markets for different bidding zones

8.8.3 Market barriers for consumers

The low demand among Norwegian households and businesses must be seen in the context of a traditionally low and relatively stable price level, as well as the authorities' general recommendation to use spot price agreements. If customers make an informed decision to use spot price agreements and not fixed price agreements, this is not a market failure, and low demand will be the correct market response for these customers.

However, given that the markets will change in the future with a greater degree of price volatility, it is questionable whether consumers, both households and businesses, have a sufficient basis for forming an opinion on expected market developments and then making such an informed decision. Expectations and forecasts for developments in both price levels and volatility are not readily available to ordinary customers. A lack of available information about developments in the electricity market may therefore be a source of market failure on the consumer side.

There is also little incentive for households to enter into new fixed price agreements as long as they receive electricity subsidies. The electricity subsidy means that 90 per cent of the cost above 70 øre/kWh is covered by the state, and the electricity subsidy scheme thus ensures households an upper ceiling for the price as long as the scheme lasts. Entering into a fixed price agreement is therefore more of a risk for the customer.

For companies, it may be a barrier that the prices in the management products (cf. chapter 8.6.2) are too high. 8.6.2) are not available in the same way as the terms of the spot price agreement. The company agreements are largely customised, and different terms and conditions affect the companies' competitiveness. The fact that the terms of the agreements affect the companies' competitiveness means that they also have a different risk assessment than households. In a situation with large fluctuations in the spot price, companies will have to assess the risk of entering into a fixed price agreement at a time when the spot price and also the contract price are relatively high. If they enter into agreements with higher prices than their competitors, this will weaken the company's competitiveness. The companies are thus not only assessing predictability, but also costs relative to others in the industry. This assessment is difficult to make in a market situation with major fluctuations in price levels. This is not a market failure in the retail market per se, but will affect companies' desire and ability to enter into fixed-price contracts within what is considered an acceptable risk.

For the new fixed-price agreements under the temporary resource rent tax regime (see chapter 8.6.4), it has been emphasised as a market barrier that most of these agreements have a fixed volume in each hour of the day, and that it is therefore difficult for companies to assess the total cost when they have to sell electricity in hours they do not use it, and buy the volume they need beyond the agreement in hours they use more.

8.8.4 Price protection for large power-intensive consumers

As described in chapter 8.6.3 and 8.6.4 a number of large power-intensive companies enter into bilateral agreements with power producers, where the terms of the agreements are based on expectations of the development in market prices, and the use of long-term price hedging is organised through a guarantee scheme and special rules for determining resource rent tax.

In addition to entering into contracts with hydropower producers, several industrial companies have entered into long-term contracts with individual wind power projects. With a lower degree of development of onshore wind power projects, this type of access to price hedging is reduced.

Some major industry players have stated that in recent years it has become more difficult to enter into long-term power purchase agreements (PPAs) (THEMA 2023). The reasons for this may be, for example, increased uncertainty about prices, greater price differences between bidding areas and declining development of onshore wind power production. However, THEMA concludes that larger electricity customers have sufficient opportunity to enter into long-term agreements, even though the market has become more limited in recent years.

8.9 Price sensitivity among electricity consumers

The extent to which customers adapt their consumption to prices is known as price sensitivity. Price sensitivity can depend on a number of factors - such as the availability of information about price levels, whether it is actually possible to reduce or shift electricity consumption and also the extent to which customers think it is worth the inconvenience of changing consumption to reduce the cost of electricity.

Price sensitivity will typically vary depending on the type of electricity contracts customers have. Fixed price agreements without volume limitation will typically remove the incentive to reduce consumption during periods of great scarcity and high spot prices. At the same time, these are the most common price hedging agreements for households today. In the business sector, a mix of fixed and spot prices is more common, so that customers generally have stronger incentives to adjust their consumption to the short-term price level in the market.

Statistics Norway's statistics for electricity consumption show that consumers have reacted to the electricity price level in 2022, including with electricity subsidies for households. Household consumption was 12 per cent lower in 2022 than in 2021. The business sector also saw a clear decline in electricity consumption in 2022 in many industry groups. The biggest exception was petroleum extraction, which saw a clear increase.

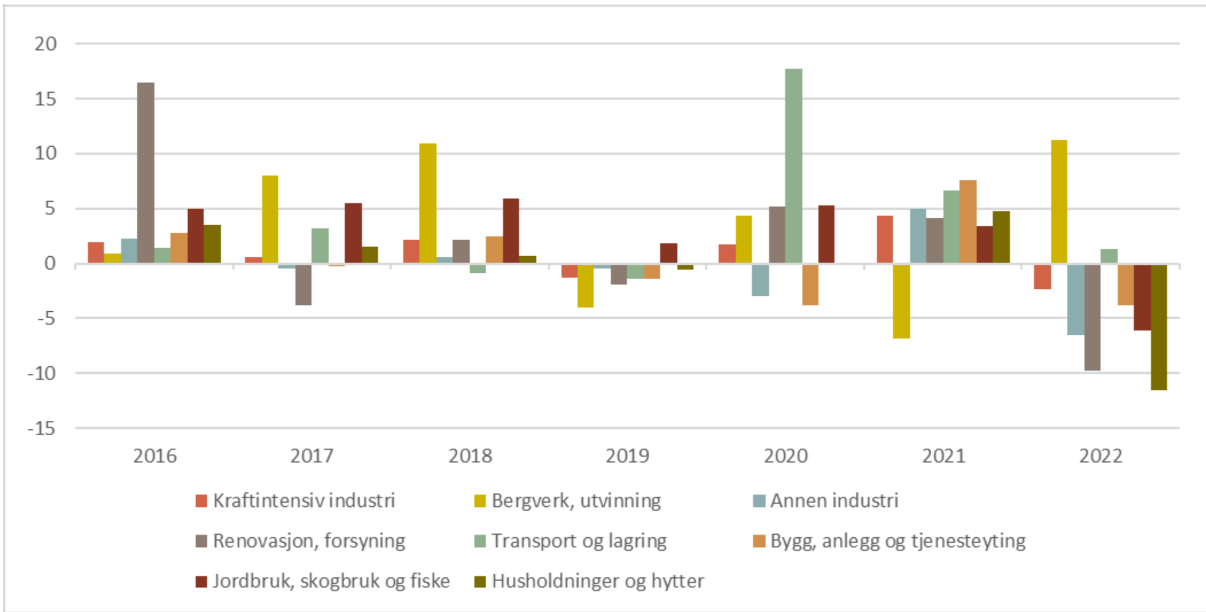

Figure 8-1 Annual percentage change in electricity consumption (measured values, not temperature corrected) (Source: SSB)

Household electricity consumption in the winter of 2021/2022 was clearly lower than it would have been if the price level had been at the same level as in previous years (Dalen og Halvorsen 2022). Households' ability to reduce their electricity consumption varies depending on their housing situation, with households in detached houses having a greater opportunity to reduce their total consumption and substitute with other energy sources than households living in blocks of flats. The analysis also shows a delay in electricity savings - it increases when prices start to fall again. There is also little in the findings to indicate that households actively take the electricity subsidy into account when making savings decisions.

In the summer of 2022, SIFO conducted a survey among households on electricity contracts and electricity consumption (Tangeland, et al. 2022). The results show that a number of customers have implemented both measures to shift electricity consumption to times with cheaper electricity, and also measures to reduce electricity consumption in total:

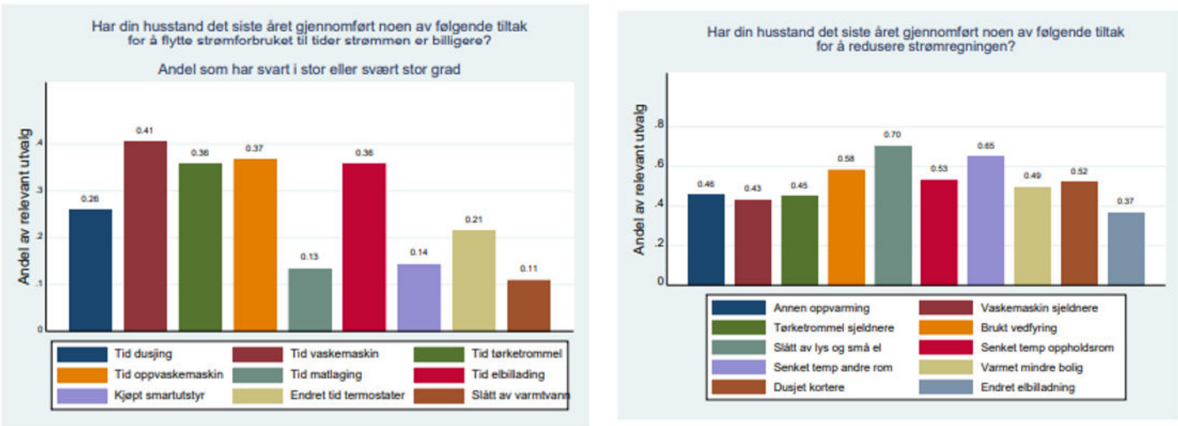

Figure 8-2 Electricity consumption and flexibility in households (Tangeland, et al. 2022)

It seems clear that households are flexible and save energy during periods of high prices. They shift consumption to times of the day when it is reasonable to assume that prices are lower. However, whether this flexibility is actually linked to hourly electricity prices is uncertain. In SIFO's survey, 4 per cent state that they check electricity prices several times a day and 16 per cent state that they check daily. The remainder check weekly, less often or never.

As Figure 8-1 shows, there has also been a clear decline in electricity consumption in a number of industries. High electricity prices incentivise companies to reduce consumption and shift consumption to low-cost hours. A number of companies have implemented energy efficiency measures. One example is that the funds in the energy subsidy scheme for businesses were largely used for energy efficiency measures, particularly in buildings. Some businesses may also have reduced their production and thus also their electricity consumption.

However, in some companies where electricity is used as an input factor in production, it can be more difficult to reduce electricity consumption in the short and long term for a number of reasons:

- Industrial production is regulated by labour agreements and deliveries are contractually fixed, which means that the flexibility to shift consumption can be low.
- Changes in production patterns may require changes in staffing.
- Significant reduction or the ability to shift consumption requires major investments that take time to realise - and are not necessarily commercially profitable
- Some processes, such as in power-intensive industries, are dependent on a continuous supply of electricity and are therefore inflexible

Reduced electricity consumption in the business sector may also be due to reduced production due to lower profitability. We do not have figures on the extent to which companies have reduced their activities as a result of high electricity prices. Overviews of industrial activities in Europe show that a number of energy-intensive companies have reduced, closed down or relocated production during the period of high electricity and gas prices.

8.10 Competitive prices

The committee's mandate specifies that the review should take into account the need for competitive electricity prices for businesses. We understand competitive prices as electricity prices that are relatively low compared to other countries. An assessment of whether prices are competitive therefore depends not only on Norwegian price levels, but also on comparisons with price levels in countries and markets where Norwegian companies have competitors. If other countries implement even more effective measures than Norway, or introduce support programmes for businesses, these countries may become more competitive. In this report, we only look at the level of the electricity price itself. An overall assessment of competitive electricity prices must also include a comparison of taxes, fees, grid rent and any other costs that come on top of the electricity price, as well as any subsidy programmes that reduce prices and thus companies' total electricity costs.

There may also be different electricity prices within Norway. Since 2021, we have seen large price differences between the bidding areas for central and northern parts of Norway compared with southern parts. In the summer months of 2022 and especially during the summer of 2023, there have also been price differences within southern Norway. Prices in NO2 have at times been much higher than in the rest of the country. This means that companies in the same industry can face very different prices.

8.10.1 Competitive prices abroad

Which countries Norwegian companies compete with varies from industry to industry. The EU is by far our most important export and import partner, both for goods and services. What the EU and its member states choose to do with electricity prices in the retail market is of key importance to many

Norwegian companies. Norway has historically had low electricity prices in a European context, which gives Norwegian companies a competitive advantage.

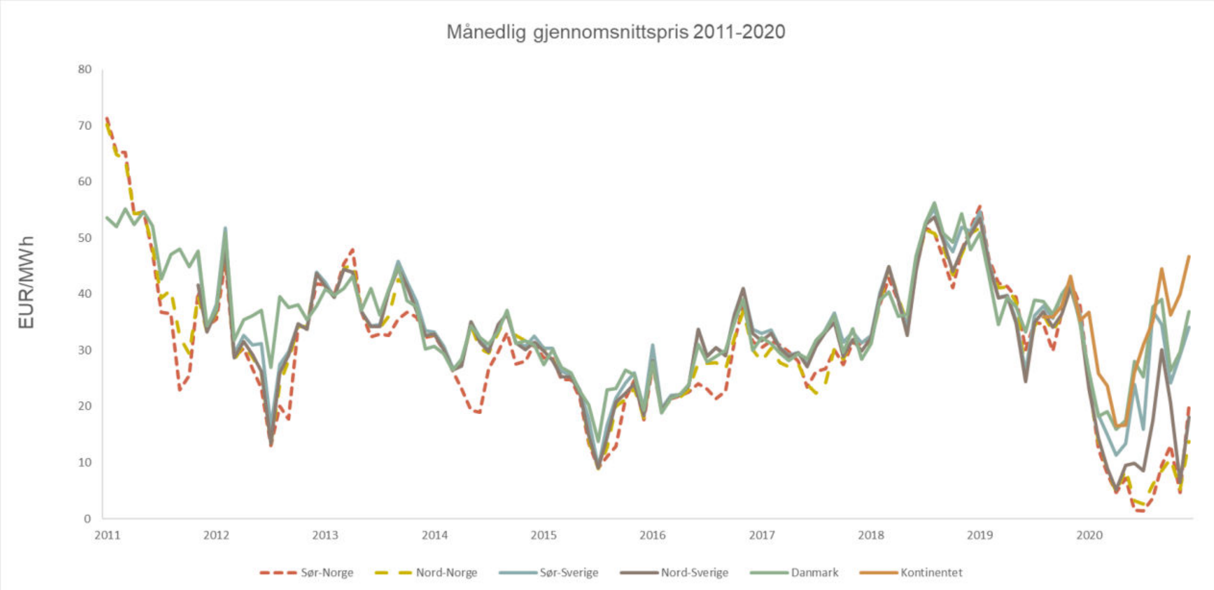

Figure 8-3 Monthly average spot price in the period 2011-2020. *The continent consists of Germany, the Netherlands and France (Source: Nord Pool)

As described in chapter 11 in the wake of the high energy prices, the European Commission has initiated a reform of the regulations for the electricity market, mainly with the aim of building more well-functioning markets, better opportunities for price protection for consumers and cost-effective support systems for initiating new power generation. There is no direct regulation of prices, but to some extent there is an opening for more regulation of the supply of contracts. It is too early to say how the regulations will be implemented when they are finalised and what the result will be in the retail market.

Chapter 12 discusses the long-term development of the electricity market and possible outcomes for the competitiveness of Norwegian electricity prices. The foundation for competitive prices for electricity customers is the electricity prices set in the wholesale market. The most important measures to ensure Norwegian competitiveness are therefore measures that can affect wholesale prices in Norway.

However, the retail market is also important in this context. In order to ensure competitive prices vis-à-vis Europe, a first step is to make conditions as similar as possible by harmonising market rules and market design in Norway and the EU countries. The EU's regulations for the electricity market are largely in favour of this, but there is also room for national adaptations. It is therefore important that national adaptations in the actual market design do not lead to different competitive conditions for businesses in different countries. It is also essential that EU countries do not subsidise their businesses beyond what Norway itself might do. Conversely, it cannot be assumed that national adaptations in Norway that favour business in Norway will go unnoticed in the rest of Europe.

If the authorities in Norway and the EU want to give businesses lower electricity prices than the market price, this will constitute a form of state aid. As a general rule, providing electricity prices to businesses that are below wholesale prices is illegal state aid, but there are exceptions. The committee has commissioned two memoranda that together provide a brief summary of the possibilities for granting aid within the regulations of the EEA Agreement (Hjelmeng 2023, Mathisen 2023) . However, ensuring a lower market price in Norway than in the rest of Europe is legal.

The competitiveness of European energy-intensive industry is being problematised by various European countries in light of the increased energy prices and subsequent reduction and closure of industrial activities in Europe. Some countries have introduced temporary support programmes for industry. Norway had a support programme in the fourth quarter of 2022. Sweden and Germany have both introduced support schemes for businesses, which are discussed in more detail in chapter 11.

From CO_2 compensation to CBAM

Power producers in the EEA are covered by the EU Emissions Trading Scheme (ETS). The producers' costs of purchasing CO_2 allowances are passed on to electricity prices to the extent that fossil fuel power generation sets the price. The compensation is intended to prevent CO_2 costs in electricity prices in Europe from causing European industry to be outcompeted by companies in countries without similar climate policies. In other words, the programme is aimed at maintaining competitiveness vis-à-vis countries outside Europe. The introduction of CO_2 compensation is voluntary and is decided by each individual country. Norway and 14 other countries in Europe utilise this scheme. In Norway, the compensation has increased from 1 øre/kWh in 2013 to 12.6 øre/kWh for 2022.

The EU is now in the process of introducing a mechanism for pricing emissions from imported goods (Carbon Border Adjustment Mechanism, CBAM). In the long term, CBAM will replace the ETS quota system for certain sectors. The aim is for importers of certain goods into the EU to pay the same price for emissions from the production of the goods as European producers are charged through the ETS. The mechanism is intended to prevent carbon leakage (the production of goods being moved to countries with lower climate ambitions and lower pricing of emissions than the EU). The mechanism will initially apply to imports of cement, electricity, fertiliser, iron and steel, aluminium and hydrogen. One consequence of CBAM is that European industrial products will be more expensive than similar products from competitors in countries without carbon pricing. Initially, CBAM only applies to direct CO_2 emissions, but the scheme can be extended to cover indirect emissions such as CO_2 via power consumption.

If the government proposes this, the Storting may have to give its consent if CBAM is to be incorporated into the EEA Agreement. This is only relevant if the CBAM regulation is amended to include indirect emissions from power generation in the calculation of indirect emissions. By 31 December 2025, the European Commission must submit a report that includes an assessment of this.

Support programmes of a more permanent nature are also being discussed. Germany's environment minister has put forward a proposal to give German power-intensive industry its own industrial tariffs for ten years to deal with the high prices during a transitional period. France has been a driving force in favour of the possibility of using revenues from contracts for difference to reduce electricity prices for consumers, including businesses. The forthcoming electricity market reform in the EU will most likely allow for the redistribution of revenues from contracts for differences, but which consumer groups this will apply to has not yet been clarified. If this in practice becomes a possibility for electricity price support to businesses, it could distort competition within the EEA, depending on the scope of contracts for difference and redistribution in different countries. Norwegian authorities have announced a competition for differential contracts for Southern North Sea II. Any redistribution of revenues in high price periods has not been discussed.

It is unclear to what extent Germany or other countries will implement permanent measures to lower electricity prices for businesses. There is also strong opposition among EU member states to regulations that create different framework conditions. However, if policy development is such that there are greater opportunities to provide permanent support to businesses, this will affect the competitiveness of Norwegian businesses if they are not given the same conditions as businesses in countries with which they compete.

For parts of Norwegian industry, power prices outside Europe are crucial for competitiveness. Some industries compete with players based in, for example, China, the Middle East or North America. The same applies to a number of other European players in power-intensive industries. Common European rules basically ensure that European competitors are on as equal a footing as possible, even against competitors from third countries. However, if power prices in third countries become significantly lower than in Europe, either through market mechanisms or subsidies, the competitiveness of Norwegian and European players will be threatened. All measures that favour lower Norwegian electricity prices will improve the competitiveness of Norwegian companies, but are not a guarantee that the price level will be competitive internationally. Chapter 12 describes that the price level will probably increase in both Norway and Europe. If countries outside Europe do not see a corresponding price increase, this will have a negative impact on the competitiveness of Norwegian players.

8.10.2 Competitive prices between regions

Norway is divided into five bidding areas, as described in chapter 7.1. Although we have several bidding zones, the price differences within Norway have not been very large over time. From 2021, however, we will see major price differences between northern and southern parts of Norway. The grid capacity within Norway, together with the geographical distribution of hydropower resources, has prevented the price increase resulting from Russia's war against Ukraine from spreading to central and northern Norway. In autumn 2022 and autumn 2023, there have also been differences between the bidding area in southwest Norway and the two other areas in the south, see also chapter 7.1.3.

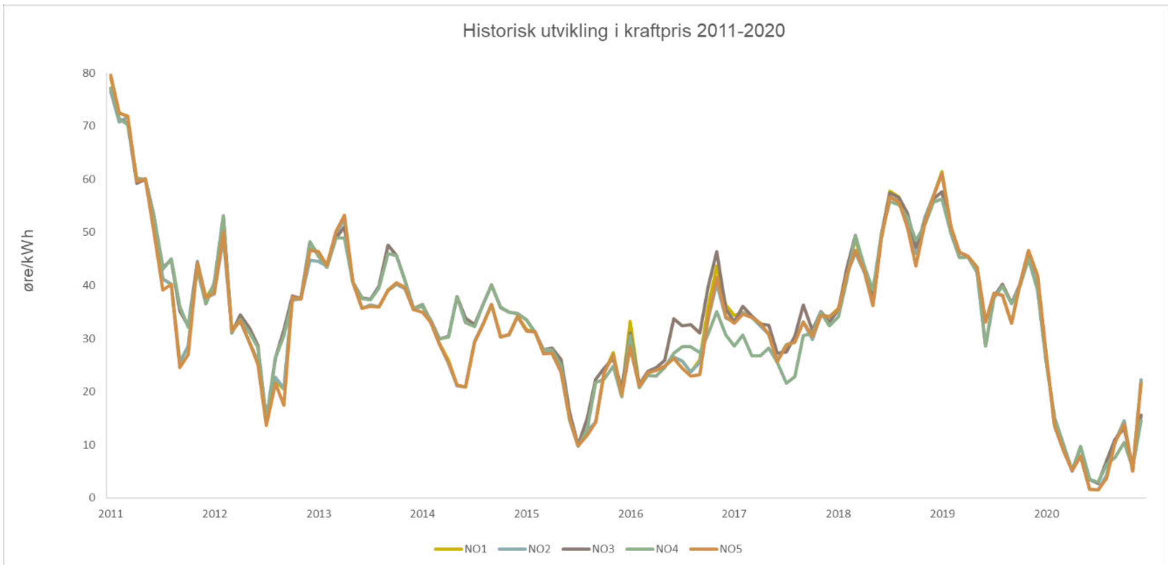

Figure 8-4 Monthly average spot price in Norway in the period January 2011 - December 2020 (Source: Nord Pool)

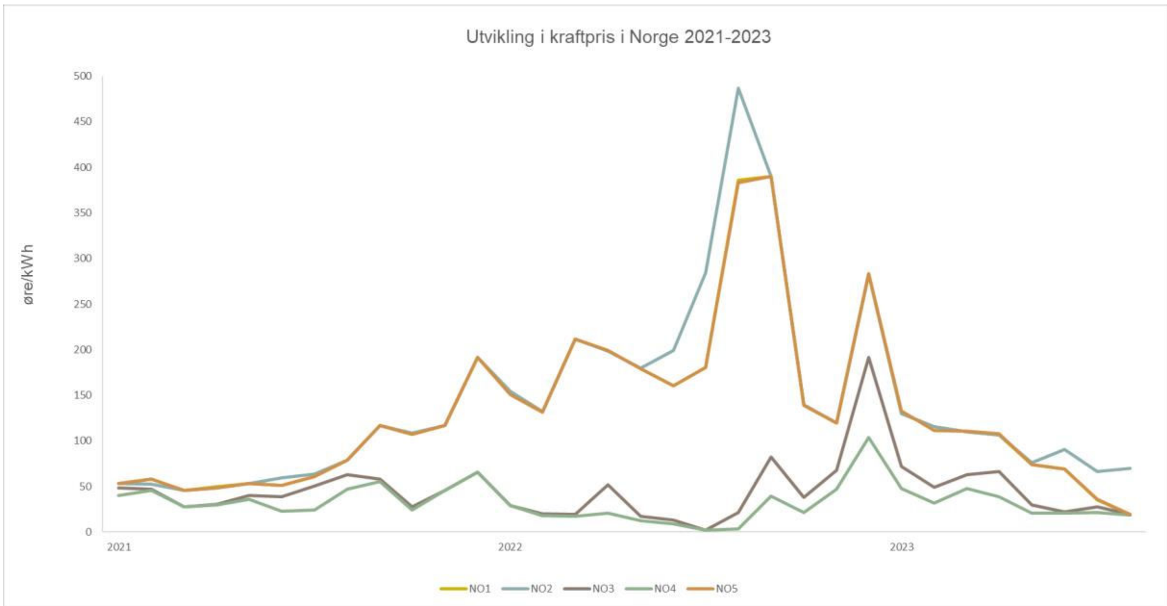

Figure 8-5 Monthly average spot price in Norway in the period January 2021 - August 2023 (Source: Nord Pool)

Differences in electricity prices between different areas can distort competition for businesses within Norway. Companies located in areas with lower electricity prices are more profitable. Relevant measures to equalise prices between bidding areas are mainly long-term:

- Better network capacity between bidding areas
- Better utilisation of network capacity between bidding areas,
- Improving the power balance in bidding areas with high prices - increasing production and/or reducing consumption

Statnett and the other Nordic TSOs are working on flow-based market coupling (see fact box in chapter 5.6) as a method for determining trading capacity in the grid. This will contribute to better utilisation of existing grids. Flow-based market coupling is planned to be introduced in the first quarter of 2024.

High prices in an area make it more profitable to expand electricity production, which will help to drive prices down. At the same time, low prices in an area make it more attractive to localise consumption there, and over time this will push prices upwards. In this way, the market helps to equalise prices, but this is a development that takes a long time.

Changes to the bidding areas for a common Norwegian zone and the effect of expanding grid capacity beyond what is socio-economically profitable are analysed in chapter 15.4.7. There are few short-term measures to equalise price differences over short periods. If you want to equalise price differences in the short term, the alternative is some form of support schemes for companies in high-price areas, which must then be assessed against the possibilities for such support under state aid law, cf. the review of different types of support schemes in Chapter 17.

8.11 Organisation in the retail market in other countries

Both wholesale markets and retail markets are organised differently globally. The Nordic and European wholesale market is more decentralised and market-based than many other areas, which may have a greater degree of control of both the wholesale and retail levels. Some markets have regulated prices to end users based on the regulation of prices in the wholesale market, for example in some US states.

The European electricity markets are based on a division of the electricity market into a wholesale level and a retail level, as is the case in Norway. There are varying degrees of competition and supply on the supplier side at the retail level. For example, some countries have had a much greater degree of fixed-price contracts and few suppliers, which contrasts with the Norwegian market. Countries that have introduced competition are often dominated by a few large players on the supply side (see also the overview of the largest suppliers in the Norwegian market above).

8.11.1 Price regulation in the European retail markets

EU countries have different traditions for regulating retail prices for electricity, which has resulted in national markets that look very different. The playing field is still not completely level, and the fact that some countries still have price regulation schemes does not necessarily mean that it will be unproblematic for a country that has not had a tradition of regulated prices to introduce such schemes now. It is the Commission's intention that member states gradually move away from price regulation, as market-based prices could incentivise consumers to respond to price signals, adopt new technology and help provide the flexibility needed in the power system through the green transition. What is unclear is how long the process of phasing out price regulation will take, and whether the ongoing power market reform may result in greater room for manoeuvre for intervention in retail prices than is provided for in the current regulations.

The Clean Energy Package (CEP, fourth energy market package), which came into force in the EU countries in 2019, was intended to mark a break with member states' price regulation and a move towards market-based prices in Europe's retail markets. The Electricity Market Directive of 2019 lays out the basic principles of the market, whereby member states are to ensure that electricity prices reflect supply and demand, and electricity sales companies are to be able to determine the price they offer their customers given sufficient competition in the market.

When the CEP was negotiated, the member states opposed the Commission's proposal to set an absolute end date for price regulation. The final 2019 directive therefore contains no deadline for phasing out, and also allows for some exceptions to the principle of market-based prices. This applies, for example, to the member states' right to regulate prices for a limited period for vulnerable or energy-poor households. Furthermore, exemptions may be granted for a transitional period if the national retail market is in a process of transition from a national market defined by regulated prices to one defined by open competition. Many of the EU countries that still have regulated retail prices are in such a transition process, and most of them report to ACER that the schemes will be phased out in the period 2023-2026. France's ARENH scheme for industrial power is an example of a scheme that is scheduled to be phased out in 2025. Information on which EU countries still have price regulation can be found in ACER's Market Monitoring reports.

In reality, the national processes of phasing out price regulation have been slow, and it is possible that the pandemic and energy crisis that followed the entry into force of the CEP will motivate member states to request postponements of the planned phase-out dates. Furthermore, the ongoing power market reform was initiated in a context of very high energy prices, where member states have had an interest in creating more room for manoeuvre to protect their end users. It is possible that this reform may lead to a regulatory framework that allows for more market intervention than the CEP envisages, but the outcome of the reform is not yet clear.

In 2025, the Commission will assess progress towards market-based prices in the retail markets, as well as the need for further legislative changes to the Electricity Market Directive. This may involve a new attempt by the Commission to introduce an absolute end date for price regulation in the retail markets.

8.11.2 Examples from some European countries

The EU's ambitions to phase out regulated prices and increase competition at the retail level will both facilitate consumers contributing energy efficiency and flexibility to the system, while also enabling consumers to reduce their own costs by ensuring that price signals reach the retail market. Until now, the lack of competition at the retail level in Europe has meant that some consumers have had little opportunity to switch suppliers and choose between contracts, which in turn means that the surcharges they pay on top of the wholesale price are high.

An important reason for the differences in contract forms for households and other relatively small electricity customers among European countries is the major differences in the type of electricity meters installed. In Norway, virtually all electricity customers have a so-called smart meter, which measures consumption hour by hour. This is less common on the continent - in many countries, almost no households have such advanced meters. This is again linked to the fact that electricity accounts for a small proportion of household energy consumption on the Continent. In many countries, a normal household uses between 1,500 and 3,000 kWh per year. In Norway, households use around 16,000 kWh on average. Without a smart meter, it makes little sense to offer contracts where the price varies hour by hour - neither customers nor suppliers know exactly how much each customer uses each hour.

United Kingdom

In chapter 11 describes the work on a long-term power market reform in the UK and the structure of the wholesale market, as well as crisis measures in the retail market. The retail market in the UK was deregulated in 1999. There were a number of measures in the market to improve competition, including measures for passive consumers. To prevent this customer group from paying higher prices than active consumers, a six-month price for standard variable contracts calculated by the regulator was introduced in 2019. This price is based on the future price and was previously set every six months, with notification of the price level one month before it came into effect. This price effectively becomes a price ceiling, with suppliers competing to deliver contracts below this price.

With increased prices and a price cap based on six months at a time, there was a large difference between wholesale prices and the fixed price in the contracts during the price increase in 2021. This increased the risk and led to supplier bankruptcies. The challenges were greatest for suppliers who had not hedged their obligations to electricity customers. As a result, the price cap period was shortened from six to three months in autumn 2022. As a temporary crisis measure, the UK has also introduced price caps for households as a support programme. In practice, this has weakened competition in the market, as all providers offer roughly the same price, close to the price cap. However, the price cap has now been above the fixed tariff for periods, which provides a better basis for competition in the market.

France

The organisation of the retail market in France stems from the fact that the French power market has a large dominant player, EDF, which mainly produces nuclear power and accounts for 70 per cent of the country's power production. EDF is a vertically integrated company and is also a seller in the retail market. As a result of EDF's dominant position, France has introduced measures in the market to increase competition.

Small consumers can choose a regulated price (TRV). This price is set twice a year by the French government, based on wholesale prices and distribution costs, among other factors. Although this price is offered directly only to small consumers, the regulated price (as in the UK) becomes a reference price for the entire market and acts as a price ceiling for offering contracts.

Furthermore, EDF is obliged to offer other electricity suppliers a given volume of power at a fixed price. This is called the ARENH scheme, which was established in 2011 as a temporary arrangement until 2025, with the aim of giving electricity customers freedom of choice of supplier while allowing them to benefit from the competitiveness of French nuclear power. As of 2022, the price in the ARENH scheme is EUR 42/MWh. Whether electricity suppliers wish to purchase the volume in the ARENH scheme depends on whether the fixed price is above or below the wholesale price. For several years, the ARENH price has been the highest, and the volume has only been partially utilised. When the ARENH price is below the market price, demand is higher and the scheme becomes a form of redistribution.

When the ARENH scheme is to be phased out in 2026, the French authorities want to replace the scheme with a combination of differential contracts for power generation based on production costs for nuclear power and long-term contracts for electricity consumers, but are facing opposition from other EU countries, as other countries believe this would in practice mean subsidising electricity consumers.

From 2019, the price has been below the market price, and demand has exceeded supply. As a result of higher electricity prices in recent years, the ARENH volume has increased from 100 to 120 TWh per year, and the authorities have reduced the tax on electricity consumption. See also chapter 11 for more information about France.

Italy
Until 1999, electricity supply in Italy was centred in a vertically integrated state monopoly, Enel (Ente Nazionale per l'Energia Eletrica). Reforms in the market unravelled this structure. Today, Enel still has a major position in the supplier market. To avoid market failure as a result of multiple vertically integrated companies in Italy, companies that both produce energy and are suppliers in the retail market must separate these activities into different entities/companies.

The Italian retail market has historically consisted of different types of contracts: a standard contract based on the wholesale price, but where the regulator has set the price to the consumer and thereby regulated the price the supplier receives. This type of contract is now in the process of being phased out. In addition, there is a contract for vulnerable households where the price is also based on the wholesale price, but the total cost to the end user (the costs on top of the wholesale price) is regulated. The last category is wholesale price-based contracts, where suppliers buy electricity in the market and offer contracts to consumers freely. The share of such contracts has increased in recent years, even before the phasing out of standard contracts.

Although Italy has seven bidding zones, as far as the Committee understands, all electricity suppliers in Italy can use a common, national wholesale price for consumption as a basis for pricing the contracts they offer their customers. This PUN scheme is described in chapter 15.4.7. This is a price equalisation mechanism between bidding areas that means that areas with low prices pay part of the bill for areas with high prices. However, from 2025, the PUN scheme will no longer be part of Euphemia (see 15.4.7 on barriers). It is not known what the retail market in Italy will be like then.

Sweden
The Nordic retail markets have many similarities (with the exception of Iceland). There is a large number of suppliers, different types of contracts are offered, the retail price is closely linked to the wholesale price, there are low switching costs and relatively active customers. The retail market in Sweden was opened to competition in 1996. It differs from the Norwegian market in one respect: Swedish households are choosing fixed-price contracts to a significantly greater extent - either in the form of contract types that are also familiar in Norway, with a fixed price for a certain number of months or years, or in the form of so-called mix contracts, where half of the customer's consumption

has a fixed price and the other half is linked to the spot price. In this way, customers achieve an equalisation of their energy costs over time. In periods with very high spot prices, the electricity customer's price is still lower. In periods with very low prices, the electricity customer still has to pay a higher price than the spot prices in isolation would indicate.

Denmark
In the first few years after the deregulation of the Danish electricity market in 2003, households and other relatively small electricity customers were not allowed to choose their electricity supplier. Instead, energy companies were required to offer customers electricity contracts that reflected the conditions in the wholesale market - in a sense, as a cost-price principle. Practice showed that although the purpose of this was to protect households from the potential negative consequences of competition in the wholesale market, households paid significantly more for electricity than the larger customers. It was generally assumed that the reason was that if the energy companies were unlucky with their timing in the future market and purchased power for delivery next year at prices that subsequently proved to be high, these contracts were placed in the business that supplied households. If, on the other hand, they were lucky and achieved relatively favourable purchase prices, these contracts were used to supply customers exposed to competition. The scheme was discontinued after a few years.

8.12 What could lead to lower and more predictable prices in the retail market?

The retail market for electricity has been very demanding in recent years due to the increase in electricity prices and the unpredictability of the market. The challenges faced by electricity end users are not only related to the function and complexity of the retail market itself. Customers' challenges are also closely linked to the wholesale market and the very close and direct link between the wholesale and retail markets:

- Historically high price levels have major consequences for consumers
- The unusual prices affect confidence in both the wholesale market and the retail market for electricity
- This is compounded by the fact that it is difficult for people to understand the underlying mechanisms for price formation in wholesale markets
- Recent years have not only seen high price levels, but also considerable variation in price levels. Going forward, prices may become more volatile than usual. Uncertainty about expected developments may mean that customers instead expect prices to fall back to a "normal" stable level, as has been the case until the summer of 2021.
- Uncertainty about future price levels affects the risk for both producers and customers when making investment decisions. A greater likelihood of price fluctuations in the short and long term makes investment decisions more unpredictable and risky. This increases the cost of making investments in both production and consumption.
- For the business community specifically, price developments also pose challenges in terms of competition, through price differences both within Norway and between Norway and abroad.

Apart from providing more information to end users about pricing and future market developments, these challenges cannot be solved by improving the retail market. Other instruments, such as support and incentive schemes, may have to be used. Measures to improve the market do not change the fundamental relationship between market prices and the retail price. If the authorities want to use measures in the retail market to give consumers lower prices than the price in the wholesale market and the futures market, this must be regulated in measures that provide a form of direct support.

Measures to deal with market failures in the retail market itself can nevertheless help to provide lower prices in general and more security for consumers through a more efficient market and thus lower surcharges, while increased use of price hedging can contribute to more predictable prices. However, prices will not be significantly lower than the current level, as the surcharge that electricity suppliers receive does not normally constitute a large part of the price in an electricity contract. Improvements in the market will not result in lower prices for consumers than the market price.

The retail market for electricity has been widely criticised as being difficult for consumers to relate to, and recent supervisory activity shows that major players on the supplier side have deficiencies in the follow-up of consumer protection regulations. On the other hand, it seems that in the Norwegian retail market there is generally a good correlation between the market price and the price consumers receive, and it is easy to find information about contracts and low costs when switching contracts. A number of measures have been taken in recent years to improve the market situation, while it appears that there are still grounds for looking at improvements in the market.

Another reason to look at the framework conditions for the market is the prospect of a more complex retail market, where the market must solve consumers' desire for predictability and also the system's need for flexible consumption. Full predictability for consumers will only be achieved in a market where everyone has a fixed price for all the electricity they buy. However, this is not a feasible solution for several reasons. Firstly, the price risk for suppliers under such agreements would make them very expensive. Secondly, it would be unfavourable for the power system and security of supply to have consumption that does not react to changes in market prices.

Achieving predictability and consumer flexibility at the same time can be solved in several ways, for example by having a fixed price for only parts of the electricity purchase. In this case, customers will still be affected by the spot price and have incentives to reduce consumption during periods of high prices. They will have a greater degree of security than if they only have a spot price agreement, but not full predictability.

Another solution is to look at adapting consumption so that costs are lower. Customers do not necessarily need a consistently low and predictable electricity *price*, but that they themselves have low and predictable electricity *costs* overall. Automating consumption (such as electric car charging and water heating) at times when prices are low can provide both flexibility in consumption and low costs for consumers.

With the expected development in the electricity market, the value of predictable and flexible consumption will increase. Similarly, the cost of unpredictable and inflexible consumption will increase. Some customers, particularly in the business sector, and some types of consumption are inflexible, for example due to production processes. It will therefore be natural to look at different solutions for different needs in the consumer groups in the future:

- Customers with predictable and flexible consumption: Can achieve increased predictability through partial price hedging and automation in consumption reduction
- Unpredictable and inflexible consumption: May need fixed price agreements on variable volume as well as measures beyond the market itself, such as energy efficiency and technology development to make consumption more flexible

8.13 Summary - main challenges in the market

The committee will assess measures for lower and more predictable electricity prices. Retail prices for electricity consist mainly of wholesale prices plus a mark-up. To ensure lower prices for consumers, it is mainly measures that reduce the wholesale price itself that will have a major impact.

Rectifying market failures in the retail markets can lower prices somewhat, but only in relation to the mark-up for electricity suppliers.

It is possible to improve the market for fixed price agreements so that electricity customers can choose more predictable prices to a greater extent.

In chapter 16 we provide an assessment of measures aimed at improving the functioning of the retail market. There are several challenges in the market that may form the basis for future measures, both related to the surcharge to electricity suppliers and to price hedging:

- The retail market in general
    - Still barriers for consumers on information about deals
    - Uncertainty about the credibility of electricity suppliers
    - Large market share for the largest suppliers - can be anti-competitive
    - Being a passive consumer will be more risky in the future
- The market for price hedging
    - Lack of information to consumers about expected future developments
    - Low demand in the market today - the market is becoming less efficient and more costly
    - Lack of price hedging options and collateral requirements for electricity suppliers limit supply
    - Information asymmetry about price levels - fixed price agreements are more difficult for consumers to assess than spot prices.
    - The temporary electricity subsidy programme functions as a quasi-fixed price for households, removing the incentive to enter into a fixed price agreement

Measures that can increase the use of fixed price agreements must be assessed in light of the need for stable and predictable prices versus the market's need for price signals to consumers. This can be handled, for example, through the possibility of only partial price hedging, or must be mitigated by other measures such as automation of the offer of consumer flexibility.

Measures to give consumers lower prices than the market price are discussed in chapter 16.

Part 2: The changing power system

Chapter 9 to 12 constitute part 2 of the report. Part 2 describes key development trends in Norway and Europe that will affect the price of electricity in Norway in the future, and presents a long-term perspective on the price formation for electricity. The purpose is to facilitate a thorough assessment of how various measures would affect the Norwegian power system in different scenarios in Part 3 of the report.

In chapter 9 we review the development in Norway from the Interconnection to the current power market. The Norwegian solutions developed in the 1990s were a key source of inspiration for the subsequent regulation in the EU. Important principles that were developed in Norway and eventually implemented in European law are the system of bidding zones and the arrangement whereby wholesale market participants submit their buy and sell orders to the power exchange in the bidding zones in which they have their facilities. In this way, it was in practice the power exchange that figuratively transported power from the seller to the buyer, even if they are not located in the same bidding zone. In countries that have not organised trading in this way, players must also purchase transport contracts, which creates a rigid system with relatively poor utilisation of grid capacity and large price differences between areas. In recent years, the EU has in many ways taken the initiative in regulatory development. The chapter therefore also provides a brief account of key EU regulations relating to cross-border electricity trading, which is relevant background for reading the report.

In chapter 10 we review the background to the design of the Energy Act and how the development of climate policy in Europe has affected the energy sector and the electricity market. Chapter 11 describes various crisis measures and discussions on reforms in Europe, which came as a result of the period of high and volatile electricity prices. Chapter 12 presents a long-term perspective on the pricing of electricity and includes various scenarios for the energy system of the future. The four scenarios discussed in chapter 12 are: 1) Harmony (power surplus in Norway and a lot of flexibility in neighbouring countries), 2) Foreign countries can't handle it (power surplus in Norway and little flexibility in neighbouring countries), 3) Norway sleeps through the hour (power deficit in Norway and a lot of flexibility in neighbouring countries), and 4) Tough times (power deficit in Norway and little flexibility in neighbouring countries). The chapter concludes with a brief review of barriers to investment in new power generation.

9 The EU has further developed Norwegian market rules

9.1 From carpooling to power exchanges

As early as 1971, power producers in Norway set up a kind of power trading exchange, known as Samkjøringen av kraftverkene i Norge. The aim was to be able to handle the varying inflow and production capacity of hydropower in different parts of the country more efficiently. This co-operation was a further development of the power exchange co-operation that had existed since the early 1930s. The interconnection exchange is a precursor to the spot market we know today at Nord Pool.

A number of large electricity utilities in Eastern Norway established an association called Samkjøringen in 1932. Over time, several carpooling organisations were also established elsewhere in the country. From 1971, they joined together in a joint association to utilise a well-developed grid. The association covered most of Norway's power production and handled all power exchange between members that were not contractually bound. The price was set once a week based on total supply and demand. The aim of the interconnection was to increase operational reliability, reduce rationing and reduce flood losses, given variations in production sources throughout the year and assumptions about consumption.

Prior to 1986, Statkraftverkene was a state-owned administrative organisation responsible for the construction and operation of the state's power plants and power grids. The organisation was separated from NVE in 1986. As a result of the changes introduced by the Energy Act of 1991, the company was split into two state-owned companies, Statkraft and Statnett. The Energy Act adopted in 1990 established the principle of market-based sales of electricity. In principle, this allowed market access for all Norwegian players in the energy market through the power exchange Statnett Marked AS (a subsidiary of Statnett, later transformed into today's Nord Pool ASA).

The aim was to move from state control to a market model and to establish a system to create a better balance between market prices, investments and favourable operation of the power plants, and to limit socio-economic losses related to inefficient production, i.e. to streamline and optimise water production in Norway. In 1992, Statnett SF took over the functions performed by Samkjøringen and established a spot market for physical power trading, a financial market for risk management and capacity adjustment for imbalances in the market related to supply-demand.

The changes in Norway were noticed around the world and also inspired the EU to develop regulations in the same direction. The EU's first directive on deregulation of the electricity market was issued in 1996, but prior to this, the EU had also introduced rules to prevent network owners from blocking access to the network for anyone other than themselves and their own customers (third-party access).

In 1996, Nord Pool took over responsibility from Statnett Marked AS and the Norwegian and Swedish power markets were integrated when the Swedish power market was also deregulated. Finland followed with the deregulation of its power market in 1997, followed by Denmark in 2002, and eventually also the Baltic countries. An integrated common power market in the Nordic region was established for both physical and financial trading, called Nord Pool, and today this is an integral part of the European electricity market.

Norway is connected to the European market through power cables. The first cable was commissioned in 1960. Since the deregulation of the electricity market in Norway, and gradually in the rest of Europe, Norway, the Nordic region and Europe have become more closely connected both in terms of the market and physically. Figure 13.3 shows several of the milestones in this development.

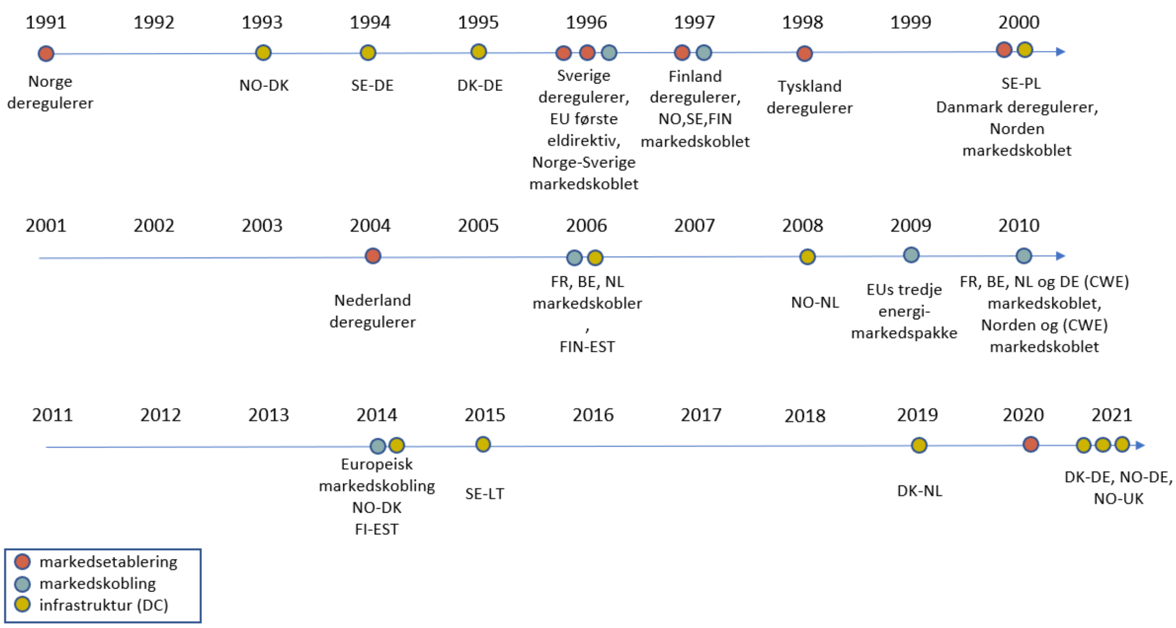

Figure 9- 1 Development of integration between the Norwegian, Nordic and European power system (NOU 2023: 3)

The EU Directive on deregulation of the electricity market was introduced based on the idea of free movement of goods, services and persons, of which electricity was defined as a commodity. Political, economic and regulatory reasons were the basis for the EU's new Electricity Market Deregulation Directive, which was implemented from the late 1990s, early 2000 and beyond. It was intended to function as an integrated market, where there were no barriers between the different member states. The intention was to establish a common integrated market with the aim of ending market monopolies, securing energy supply, increasing investor incentives and producing energy at the lowest possible price, which in turn would provide positive benefits for both private and business in the EU and improve the competitiveness of European industry.

The market model largely reflects the Nordic power market that was established and developed in Norway from 1990 onwards, a physical and a financial market as well as a balancing market in each country with cross-border co-operation. This also led to a need to establish cross-border grid prices, and various organisations had to be established to handle the physical flow between countries. Separate grid prices were established and opened up the possibility for larger customers to buy energy from other suppliers. In addition, the operations of each energy company were separated from production, which has also now been implemented here in Norway.

9.2 Selected legal acts from the EU

Greater integration of the physical energy market in Europe requires harmonisation of market design, trading systems and technical regulations in the various countries. Today, it is therefore the EU that largely sets the agenda for further development of the principles for the market. Below we will briefly describe some of the legal acts that have the greatest impact on price formation. The overview is not complete or exhaustive.

9.2.1 Third energy market package

The EU's third energy market package from 2009 aimed to create a more integrated energy market in the EU. One of the goals was to create equal conditions for all electricity customers and producers throughout the EEA. The legal acts in the third energy market package were incorporated into the EEA Agreement and implemented in autumn 2019. Pursuant to the cross-border trade regulation

(EC) 714/2009 in the third energy market package, the EU has adopted eight regulations relating to cross-border trade in electricity, known as network codes and guidelines. Four of the regulations on the electricity market[42] were incorporated into the EEA Agreement and implemented in autumn 2021. Four regulations (network codes)[43] have not been incorporated into the EEA Agreement.

Among the most central regulations related to the price formation for electricity is the Regulation on Capacity Allocation and Congestion Management (CACM). The purpose of CACM is to facilitate the efficient coupling of the European markets for the trading of electrical energy in the spot market and the intraday market. The CACM requires transmission system operators and power exchanges to work together to develop proposals for specified terms and methods on functions that need to be harmonised in an efficient power market between countries. This includes the development of a common market coupling function, i.e. the algorithm that links buy and sell bids (Euphemia), and a method for calculating available transmission capacity between bidding areas.

Since 1991, the purpose of the market mechanism has been to ensure that grid capacity and production capacity are utilised as efficiently as possible. Reasonable production should be used 'first'.

In the energy market of the future, with an increased share of renewable energy production, increased consumption of electricity and increased variation in the share of production related to weather developments (e.g. wind power and solar power) and limited opportunities to store surplus energy produced, strong variation in production will result in strong price variation.

One of the 'innovations' in European market regulation development is Flow Based Market Coupling (FBMC), see fact box in chapter 5.6. In short, flow-based market coupling is a new method for telling market participants and power exchanges how much transmission capacity the system operators can provide between areas. This new method means that the physical grid capacity can be better utilised and that power from affordable sources can to a greater extent replace more expensive sources. The method involves automating the determination of trading capacity for the power market. The method uses more detailed information about the physical power grid and looks at the entire Nordic region and Europe in context.

Results from a test period in the Nordic region show that with flow-based market coupling, grid capacity would be better utilised than with the current method (Energinet, Svenska kraftnät, Fingrid og Statnett 2023).

The Nordic DSOs conclude that flow-based market coupling in the Nordic region fulfils the requirements set by the regulators for implementation and that the method will work as expected. Improvements are continuously being worked on.

[42] Commission Regulation (EU) 2015/1222 laying down guidelines on capacity allocation and congestion management (CACM), Commission Regulation (EU) 2016/1719 laying down guidelines on long-term capacity fixing (FCA), Commission Regulation (EU) 2017/1485 laying down guidelines on the operation of the transmission grid for electricity (SOGL) and Commission Regulation (EU) 2017/2195 laying down guidelines on power system balancing (EB)

[43] Commission Regulation (EU) 2016/631 establishing a network code on requirements for the grid connection of generators (RfG), Commission Regulation (EU) 2016/1388 establishing a network code on the grid connection of consumption (DCC), Commission Regulation (EU) 2016/1447 establishing a network code on requirements for grid connection of high voltage direct current systems and generation parks connected to the grid via direct current cables (HVDC), Commission Regulation (EU) 2017/2196 establishing a network code on emergency response and restoration (ER).

9.2.2 REMIT

The Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) was adopted by the EU in 2011. The regulation concerns rules on insider trading, market manipulation and market surveillance for the wholesale gas and electricity markets.

REMIT will ensure increased transparency in the energy and electricity markets, respectively, and gives ACER the task of monitoring the EU's wholesale energy markets. Effective market monitoring requires access to data on transactions in the market as well as data on capacity and utilisation of facilities for production, storage, consumption and transmission of electricity or natural gas (fundamental data). REMIT therefore obliges all market participants, including TSOs, suppliers, traders, producers, brokers and large consumers trading in the wholesale market, to provide this information to ACER.

The regulations in REMIT apply in full to Norwegian companies for their activities in EU countries to the extent that they enter into transactions that are subject to reporting requirements. This means that they must register in one of the member states in which they are active and that all transactions they carry out in EU countries must be reported.

REMIT has not been directly implemented in Norway, but the NEM regulation contains virtually identical rules prohibiting market manipulation and insider trading, as well as requirements for disclosure of inside information. The provisions apply to physical power trading in Norway. Provisions have also been introduced to ensure that RME has access to data from the system operator and marketplace, as well as requirements for routines and procedures to detect violations of the prohibition provisions. RME is responsible for following up that market participants and persons who facilitate or organise transactions in wholesale energy products (PPATs) comply with the provisions. RME has entered into an agreement with Nordic and Baltic energy regulators with the intention of ensuring coordinated and effective follow-up of REMIT.

9.2.3 EMIR

Norway is also part of the European Market Infrastructure Regulation (EMIR). This is a system that was introduced in the EU following the financial crisis in 2008 to reduce the risk for all players trading in the financial market with derivative contracts. A derivative contract is a financial product where the product value is based on an underlying commodity such as a currency, share or raw material. The purpose of derivative contracts is to ensure that market participants can distribute financial risk among themselves. Participants with high risk-bearing costs can reduce their own risk and, through derivative contracts, encourage participants with lower costs to assume this risk. The regulations came into force in Norway on 1 July 2017 and were subsequently updated in 2019. It was introduced in the EU as early as 2012. In Norway, the Financial Supervisory Authority of Norway regulates and monitors how Norwegian companies should comply with the EMIR regulations.

The regulations are intended to regulate risk management, set a standard for reporting trades and classify the various players in the market. A distinction is made between financial and non-financial counterparties. Clear requirements are set for correct confirmation of each individual trade, and that portfolios and bilateral trades are reconciled and reported to provide good insight into the trades, agreed content and reduce risk for the parties. The trades are registered in a transaction register with the European Securities and Markets Authority (ESMA), to which the authorities have access in order to take action if financial stability is threatened.

10 Climate policy in Europe places new demands on the energy and power market

Global, European and national climate policies are creating new conditions for energy supply and power systems. Mobile energy carriers and regulated power generation are being replaced by localised and unregulated energy sources. This transition has already come a long way, and adopted political goals and measures point to an intensified development in the same direction. In this way, climate measures require and create a reorganisation of the energy supply. This will have consequences for the power market systems in Europe.

The purpose of this chapter is to highlight some of the new conditions and consequences that are being created in our country and in the world around us. A brief description is given of key conditions and events from the adoption of the Energy Act in 1990 to the latest climate policy decisions and target formulations in the UN, the EU and Norway.

10.1 The Energy Act created a more efficient and rational power supply

The Energy Act marked a paradigm shift in Norwegian power and energy policy. Until 1990, the power supply was a politically controlled and thoroughly regulated infrastructure task in society, where power prices for various consumption categories were largely determined politically. When the Energy Act was introduced in 1990, one of the assessments of the previous system was that *"Despite high technical standards and very good security of supply, there are weaknesses in the current organisation of the power supply. Prices vary greatly between districts and consumer groups, and consumption is not very flexible, even though production can vary greatly from year to year. Power plants with high development costs have been built before plants with lower costs. High development costs can be passed on to consumers because electricity utilities have a monopoly with a coverage obligation. In many cases, distribution plants and subscribers have too little motivation to engage in energy efficiency activities. These are weaknesses that mean that the fundamental goals for the power supply are not being achieved in a sufficiently good way."* [44]

The new law introduced a far more market-driven system. Decisions on resource allocation, investment needs and power prices were moved from political bodies to the players in the energy markets. This provided the basis for the development of a far more autonomous and independent value-creating power industry.

In the wake of this development, political discussions about power and energy policy became more than just a discussion about supply issues. It was also about the development of an independent energy industry on its own terms.

The new Energy Act was a consequence of a development that was taking place in society. Increasing consumption of electricity, combined with growing scepticism among the population about further development of new hydropower, created a need to utilise energy resources more efficiently. The market-based system introduced by the new law responded well to these challenges.

The Energy Act was also a child of its time in the sense that it was introduced at a time when several sectors of society were liberalised and more market-driven. This applied to the banking and finance sector from the mid-1980s, and to the telecoms sector during the same period.

The changes brought about by the Energy Act were met with uncertainty and scepticism from many quarters. The predictability previously associated with power prices, and the opportunities for

[44] Ot. Prp nr 43 (89-90) om lov om produktion, om omforming, overføring, omsetning og fordeling av energi (Energiloven) - Stortinget

political use of power prices as an industrial policy instrument, disappeared. However, the scepticism towards the Energy Act became far less as it was felt that the new system resulted in lower average power prices over time and that there was less need for the development of new controversial hydropower.

10.2 The climate challenge sets a new agenda

Climate issues really came onto the political agenda at the end of the 1980s. This happened at the same time as the ideas for a new Energy Act were taking shape - although these issues were not linked at the time. The problem of anthropogenic climate change had been recognised and discussed in some academic circles even earlier, but it was through the work on the Resource Report (NOU 1972: 1) that this problem was first introduced to the political environment in Norway. However, it was not until the consideration of the UN report "Our Common Future" (the Brundtland Report)[45] (United Nations 1987)that the topic would come to characterise the political debate in Norway and other countries.

The UN system now began systematic work on reducing greenhouse gas emissions. In 1988, the UN Intergovernmental Panel on Climate Change (IPCC) was established. The next major step was taken in Rio de Janeiro in 1992. A framework agreement for international co-operation against anthropogenic climate change was adopted. This agreement included a declaration of intent to stabilise greenhouse gas emissions at 1990 levels by the year 2000. This climate convention is an international treaty that sets the framework for extensive work to establish binding emission limitations.

The first important milestone in the endeavour to limit emissions was reached through the Kyoto Agreement in 1998. This was a legally binding international agreement with specific commitments to reduce greenhouse gas emissions and where the reduction commitments were distributed directly to the 127 countries that eventually ratified the agreement.

However, the Kyoto Agreement turned out to be a relatively weak instrument in global climate efforts. In reality, it only covered around ten per cent of the total emissions from the world's countries.

However, the UN work continued and resulted in the Paris Agreement, which was signed in 2015. This new agreement was organised differently from the Kyoto Agreement in that it is based on the countries' own reduction targets. Reduction requirements were no longer to come from above and from outside. The Paris Agreement sets a common global ambition for reduction and commits individual member states, or groups of countries, to the reduction targets they themselves report to the UN system.

Although the UN's climate work has so far yielded weaker results than intended, a strong global consensus has been created that greenhouse gas emissions must be reduced. Political measures are now being implemented in most countries. At the same time, rapid technological developments are introducing new opportunities to reduce emissions. A significant proportion of these new technologies are based on increased electrification and the transition to renewable energy.

10.3 Energy transition is the big topic

Although anthropogenic emissions of greenhouse gases to the atmosphere have several sources, it is emissions linked to the use of fossil energy carriers such as coal, oil and gas that account for the largest share of the emissions problem.

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[45] Original document available here: [Report of the World Commission on Environment and Development: (un.org)](un.org).

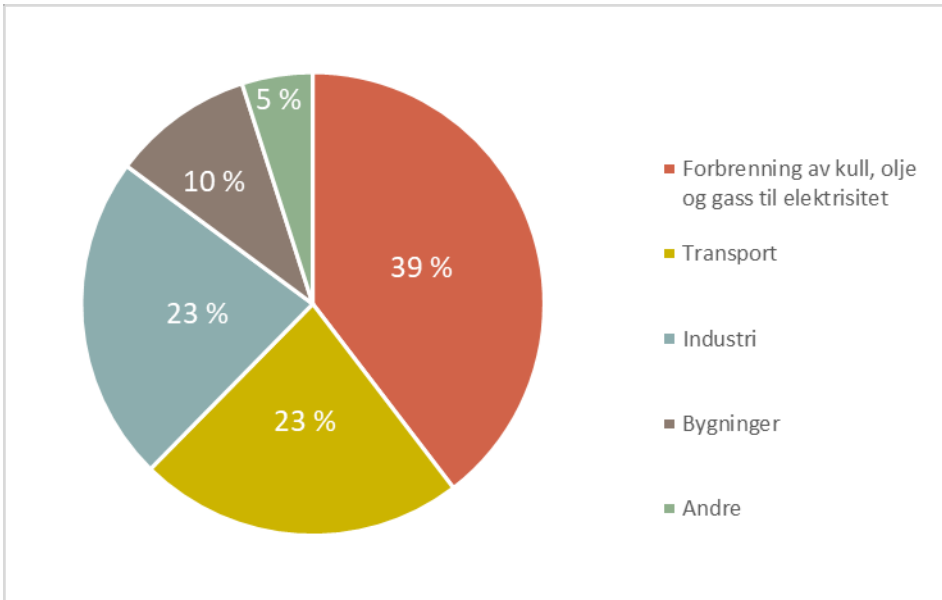


Figure 10- 1 Share of global energy-related CO_2 emissions by sector (Source: IEA (2020))

Energy-based emissions account for about two-thirds of total global greenhouse gas emissions.

A large proportion of emissions are concentrated in power plants and industrial facilities. At the same time, the most cost-effective alternative solutions will be found in the energy sector. Efforts to reduce global greenhouse gas emissions therefore focus on replacing fossil fuels with renewable energy. Some of the alternatives to fossil fuels come from hydropower and bioenergy, but most of this energy comes from wind and solar power. New emission-free energy sources will replace both direct combustion of fossil energy carriers and fossil-based electricity.

The same shift in direction can be seen in efforts to reduce process emissions from industrial production. Here, efforts are being made to replace fossil-based reducing agents in, for example, metal production with new reducing agents and production processes. One relevant measure is to replace coal with electrolysis-based hydrogen as a reducing agent in metal production.

The main path in the climate work is therefore very clear
It moves from fossil energy carriers and raw materials to renewable energy sources and production methods based on renewable electricity. Such a transition has some dramatic consequences for energy systems. It imposes completely new requirements in terms of adapting production and consumption. Today's energy and consumption systems are based on market-driven mobility and flexibility on the supply side of the energy markets. A climate-motivated transition will mean having to deal with a far more localised and unregulated energy supply. This requires more flexibility from the demand side of the energy markets than we have been used to so far.

10.4 Europe is leading the transition

Both European countries and the EU community have taken the lead in climate work by setting ambitious targets and implementing concrete measures. There may be several reasons why Europe has assumed such a role, which will not be discussed further here. It is nevertheless relevant to point out a few factors that explain and emphasise the scope and direction of the energy transition that the EU and leading European countries have chosen.

Europe had a poor supply of local energy resources even before the climate issue was on the agenda. European industrial development was increasingly dependent on oil, gas and coal from other parts of the world. When climate and environmental challenges began to seriously challenge local coal production, the situation was further exacerbated. Nor did it help matters when nuclear power came into disrepute, including after the accidents at Chernobyl and Fukushima. Europe's energy supply therefore became increasingly dependent on imports from Russia, the Middle East and Africa. These were areas and regimes that were seen as politically unstable and unpredictable. Dependence on imports from areas with geopolitical uncertainty gradually became a strong argument in favour of increasing our own energy production. The coincidence of the global climate crisis and Europe's geopolitical challenges created motivation for the ongoing energy transition. The consequences of Russia's attack on Ukraine confirmed what many had long feared. This situation is now helping to reinforce the desire for energy restructuring, away from imported fossil resources and towards local renewable energy carriers.

Nor should we underestimate the dynamics of the EU's co-operation model itself. The Union is organised around a strong policy-making body - the European Commission. The very nature of the climate problem is transnational. Solutions must be found across established national borders. This helps to make the European Commission particularly relevant in climate work. In a way, this complex of issues has had a legitimising effect on institution building and cooperation measures in Europe.

Whatever the motives and driving forces may have been, it is clear that the EU quickly got down to concrete work to follow up the Kyoto Agreement. As early as 1998, a "Burden Sharing Agreement" was adopted, which stipulated that the EU countries would jointly reduce greenhouse gas emissions by eight per cent from the 1990 level for the period 2008-2012.

Since then, the EU has tightened its climate ambitions several times. The current reduction target is set at a minimum of 55 per cent in 2030 compared to 1990 levels. The goal is to be climate neutral by 2050. The "Fit for 55" package of legislation and measures shows how the EU will achieve these targets.

Most of the work to reduce Europe's greenhouse gas emissions is focussed on the transition from fossil fuels to renewable energy carriers. The measures that are particularly relevant to the electricity supply and power systems are linked to the Renewable Energy Directive and the establishment of the emissions trading system for CO_2 .

The UK was part of the EU until 2020. After Brexit, the commitments established on the basis of the Paris Agreement were largely continued. The UK was initially one of the countries with the lowest proportion of renewable energy in its energy mix. While renewable energy accounted for just under two per cent of its total energy consumption in 2000, by 2020 it had reached almost 15 per cent. The UK is investing heavily in the further development of emission-free energy, not least offshore wind power.

10.5 The Renewable Energy Directive is a lever for restructuring

The EU Renewable Energy Directive was first adopted in 2001. The purpose of the directive was to increase the proportion of renewable electricity to 22.1 per cent of total energy consumption in 2010, compared with 13.9 per cent in the reference year 1997. This target was derived from the EU's overall target that 12 per cent of total energy consumption in 2010 should come from renewable energy sources. The target was linked both to the EU's climate strategy and to strengthening the security of energy supply.

Since then, the Renewable Energy Directive has been amended several times, each time in a more ambitious direction. The latest proposed amendment came after Russia's invasion of Ukraine in 2022. In the current directive, formally adopted in 2018, the target is set at 32 per cent renewable energy by 2030. However, the EU's 2020 Climate Target Plan states that the 2018 renewables target is not sufficient to achieve the 55 per cent emissions reduction target by 2030. It was therefore proposed that the overall renewables target be increased to 40 per cent. In a revision proposal from May 2022, it is proposed that the renewables target for 2030 be further increased. In 2023, this target is now set at 42.5 per cent.

We are witnessing a **sharpening of ambitions for energy restructuring, and this is happening at an increasing pace**. An important reason for such a development is the desire to become independent of energy imports from Russia as soon as possible. Technological and economic developments, with increasingly efficient and affordable access to energy from renewable sources, and better opportunities for automation and control of energy consumption, have also helped to make it realistic to aim for a larger and faster transition.

Through the EEA agreement, the Renewable Energy Directive also became applicable to Norway from 20 December 2011. Initially, Norway had a very high proportion of renewable energy in its total energy consumption due to the large share of hydropower in its electricity supply. Nevertheless, the negotiated requirements meant that Norway had to increase its renewable electricity production. This was an important reason why Norway, together with Sweden, established a certificate-based support programme for renewable energy - so-called electricity certificates - in 2012.

Sweden had already established such a scheme in 2003, but now the countries decided to cooperate on a system that would generate 28.4 TWh of new renewable energy by the end of 2020 (in addition to Sweden's own target of a further 18 TWh by 2030). It was not least this support system that accelerated the development of new wind power in Norway. While wind power in Norway produced less than 1 TWh in 2010, it delivered 15 TWh in 2022. The new power generated through this support scheme, around 46 TWh in Norway and Sweden, was delivered to the market through a political decision, and independently of the investment impulses and needs associated with the market price of power.

The work on the Renewable Energy Directive in the EU, and the transition to renewable energy, shows how global targets for greenhouse gas reductions have been translated into European targets and how this in turn has been followed up by measures at both European and national level.

Although the EU has some hydropower and bioenergy, the vast majority of new renewable energy will have to come from solar and wind power on land or from the sea. In this way, the EU is aiming for an energy supply that is increasingly based on the natural conditions of the moment, with little capacity for regulation. This also means that new sources of flexibility must be developed to ensure a balance between production and consumption at all times.

Wind power and solar energy have high investment costs and very low operating costs compared with the fossil-based energy system that has been in place until now. An energy transition such as the one the world, Europe and Norway are in the midst of therefore means that wholesale power prices are likely to fluctuate far more and differently than before. This increases uncertainty for investors, producers and consumers.

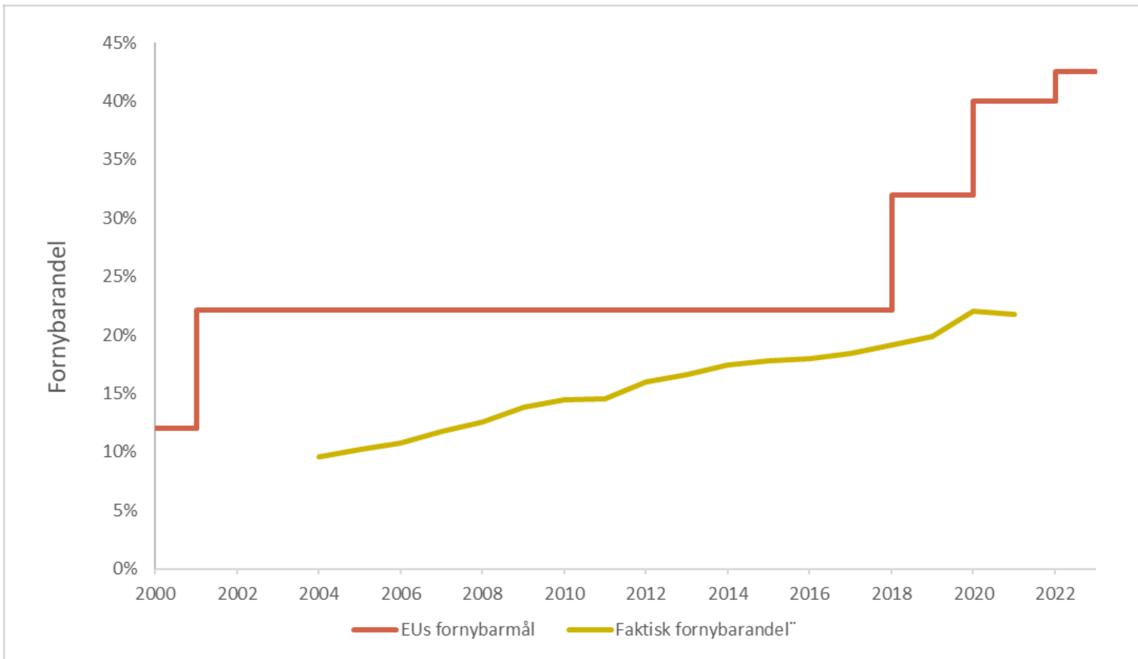


Figure 10- 2 EU renewable energy targets vs. Actual renewable energy share in the EU in the period 2004 to 2021 (Source: European Commission, *(Eurostat u.d.)*)

10.6 Norwegian climate and energy policy is becoming increasingly integrated with Europe

In recent years, Norway's climate and energy policy has become increasingly closely linked to Europe. One factor is the formalities and dynamics of the EEA Agreement. Another is related to market opportunities and system needs in the actual energy supply in Norway and Europe. Natural variations in local renewable energy production indicate that it is rational to develop more transmission capacity both within countries and across national borders.

In the early years of the climate debate in Norway, energy supply was not at the centre of the debate. This was obviously because the Norwegian power supply was largely renewable and carbon-free. At that time, discussions centred more on the consequences of transmission links to other countries and the possible price effects of coal, gas and the CO_2 quota system in the Norwegian and Nordic power market. The scheme to compensate Norwegian power-consuming industry for the price effect on Norwegian hydropower of the CO_2 price of Europe's thermal power was a result of such discussions. The scheme was introduced from 2013, see also the fact box in chapter 8.10.

2015 marked an important milestone in Norway's co-operation with the EU on climate policy. Instead of submitting a national reduction ambition to the UN programme that was to be adopted in Paris that year, Norway applied to become part of a joint commitment with the EU. Among other things, this led to a division of the climate policy goals and instruments in Norway as well. Businesses that were defined as subject to quota obligations could buy and sell quotas between businesses and countries within a given quantity framework. Other national emissions were now subject to an EU/EEA-determined national reduction target.

The direct impact on the Norwegian power system was initially (in 2015) probably limited, given that our electricity supply was based on a large proportion of regulated hydropower. However, the indirect impact of the EEA agreement and the common European climate policy must be expected to be greater. We are integrating into markets with little and expensive production flexibility, and we must increasingly electrify Norwegian society in order to fulfil our part of a binding European and national climate target. The war in Ukraine and its aftermath will in all likelihood intensify the work on energy restructuring, both in the direction of greater local production of renewable energy and an expanded opportunity for energy exchange between countries and regions.

10.7 Climate action - a new energy policy paradigm shift

The conditions that applied when the Energy Act was adopted and helped to shape the power systems in Norway, the Nordic region and Europe have changed significantly.

Climate policy measures have begun to have an impact on energy supply and power systems in a completely different way than just 10 years ago. There is still uncertainty about the progress of climate work and whether current climate targets will actually be met. This applies to the Paris Agreement, EU targets and local Norwegian climate targets. However, there is no doubt about the new direction of development resulting from a climate-motivated transition. Current policies are creating changes. Renewable energy will play a far greater role in the energy supply. Any doubts that may exist are more about the pace of change than the direction of change and the long-term consequences for the power systems.

Climate policy in Europe, with which we are closely integrated, affects the power market and electricity supply in more ways than through the actual energy transition in the countries concerned. This can be seen, for example, when power and quota prices (for greenhouse gas emissions) change in a way that disrupts the competitiveness of European industry. Such conditions can have major consequences for the energy balance in regions and countries. For example, the European aluminium industry has lost competitiveness, so power consumption and greenhouse gas emissions (in Europe) have fallen sharply over the past 20 years. At the same time, consumption of aluminium in Europe has increased significantly, which has contributed to corresponding increases in emissions in other parts of the world. These factors are behind climate policy measures such as CO_2 compensation for certain industrial sectors, and the proposals for a separate carbon tax (CBAM) on imports of certain goods to Europe, see also the fact box in chapter 8.10.1.

Electrification of LNG production at Melkøya is another example of a climate-motivated consequence in the power market. This measure must, in the government's expressed opinion, be implemented in order to fulfil Norway's part of the emission targets. The decision to do so has direct consequences for both the production and distribution of power in Finnmark, Norway and Sweden.

We are thus witnessing global targets for greenhouse gas reductions being "transformed" into European and national targets for increased production of renewable energy. This has in turn been followed up by regional and national support programmes to meet the targets and requirements set. In addition to specific targets and support measures for renewable energy production, the quota system for greenhouse gas emissions (CO_2 quotas) has tightened the possibilities and profitability of fossil-based power production. Ordinary investment criteria, profitability assessments based on the price that can be expected based on the relationship between supply and demand in the market, have thus been partially cancelled. The supply side is strongly characterised by both political restrictions and support schemes, while the political instruments for "managing" the demand side are far weaker. An important complicating aspect is also the uncertainty about the political acceptance of the encroachment on nature as a result of the development of new renewable energy.

However, the most dramatic consequence of the energy transition is that we are moving from mobile and flexible energy carriers to a system with little adjustable production capacity. Coal power, gas power and hydropower with reservoirs can be switched on and off as demand, and thus prices, fluctuate. Here, prices are a consequence of a market situation and at the same time a control signal to the producers on how to act rationally. This does not apply to the majority of new renewable production capacity. Neither solar nor wind power is demand-driven and marginal production costs are close to zero. In isolation, this means that the spot price will have its role as a management instrument in the power supply weakened until competitive options for electricity storage, such as batteries or hydrogen, are put in place.

The obvious cause of the power price crisis that hit Europe and Norway in 2021 can be linked to the energy shortage and high gas prices resulting from the war between Russia and Ukraine. This crisis situation has helped to accelerate and intensify an already planned climate-motivated restructuring of Europe's energy supply. The Norwegian power supply system must therefore recognise that the climate policy consequences for electricity production and the power market system can be expected to be greater and more rapid than previously anticipated.

A fundamental question that arises is how much of the energy consumption can be covered by an energy production that is unregulated and has a marginal cost down to zero, before the current market and regulation system must be subject to more fundamental changes.

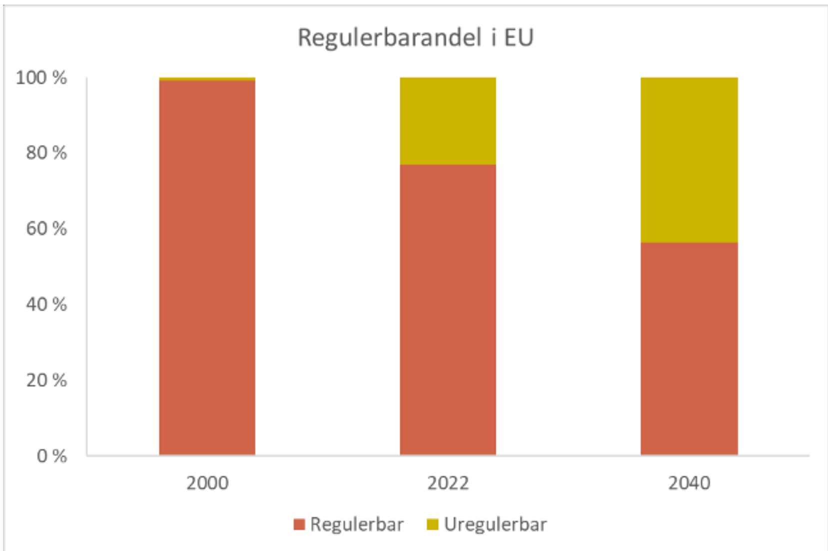


Figure 10- 3 Regulatable share in the EU in 2000, 2022 and 2040 (Source: IEA)

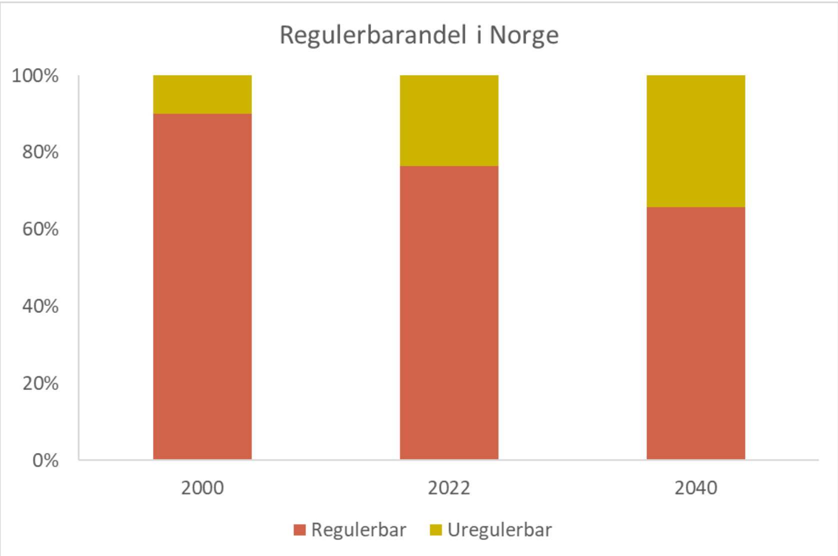


Figure 10- 4 Regulatable share in Norway (Source: SSB, NVE)

11 Crisis measures and reforms in Europe

Europe has emerged from a period of high and sometimes strongly fluctuating power prices. The challenges in the European countries have also affected power prices in Norway, especially in southern parts of the country where the connection to the European power market is greater than in the rest of the country. The mandate asks the Committee to report on the work on crisis measures and more long-term reforms related to pricing in the European electricity market, and how the implementation of proposed or discussed measures in the EU and the European countries may affect the pricing of electricity in Norway. The impact will be assessed on the basis of assumed influences from the European market, but also on the basis of whether similar measures were introduced in the Norwegian power system. It will be assessed whether it is rational to introduce alternative measures in response to the EU countries' or the UK's changes in market design.

This chapter provides a chronological review of the work in the EU and the status of the work on long-term reforms in the EU and the UK. The chapter also provides information on similar measures that have been introduced in Norway. The *assessment of similar measures* in the Norwegian power system is presented in chapter 15-17.

11.1 The main features of Europe's reform efforts

In 2021 and 2022, the EU and EU member states implemented a number of temporary measures in response to the energy crisis. At EU level, the measures largely focused on securing energy supplies in the face of Russia's cuts in gas exports to Europe, as well as strengthening the member states' ability to finance support programmes through tax measures. The EU has made little provision for intervention in the wholesale markets, with only a few countries being granted special exemptions. International trade in electricity and gas has been seen as important for securing supplies to all countries, and no trade restrictions have been introduced. To enable member states to mitigate consumers' energy bills, the EU's state aid rules allowed for temporary support schemes that are planned to be phased out when the crisis subsides. Although the state aid rules set a common framework, each member state has been responsible for support programmes for its own consumers. This has led to a wide range of different schemes in different European countries. Norway, which has not experienced a gas shortage, has been in a different situation than most EU countries. Norway has nevertheless been affected by the European energy crisis through price transmission, and has largely implemented similar or equivalent measures as the EU countries when relevant.

The EU's work on a long-term reform of the electricity market design was initially motivated by ensuring that consumers would benefit more from the increasing share of affordable renewable energy in the European power mix, and preventing volatile gas prices from driving up electricity bills as they did during the crisis. The final reform proposal preserves the basic price mechanism in the European wholesale electricity market, and new legislative changes are largely focused on facilitating price stabilisation, for example through increased use of PPAs (see chapter 6.1.3 and 6.7) and fixed price agreements. The EU's electricity market reform has not yet been finalised, and it is uncertain whether the new market rules will ultimately allow for a greater degree of support or redistribution to consumers to mitigate electricity bills. One example of this is the disagreement between member states on the extent to which the state should be able to transfer revenues from power producers to consumers through state CfD schemes[46] . One concern is that such schemes could create unequal

[46] CfD means contract for differences. In Norwegian, contracts for differences are often used. The term state CfD is often used for contracts where the state wishes to subsidise power generation, for example. In purely economic and practical terms, most CfD contracts function in the same way as long-term financial agreements,

competitive conditions in the internal market if the degree of redistribution differs from country to country. The EU's reform proposal is considered EEA-relevant, and the reform will have a direct effect in Norway if the legislative changes are included in the EEA Agreement. At the same time as the EU, the UK has initiated work on its own power market reform, but no legislative changes have yet been proposed. The discussions seen in the UK in connection with the reform have many similarities with those seen in the EU.

When the Commission presented its proposal for power market reform in March 2023, the reform was set in the context of the EU's broader response to a new trade policy climate. Russia's attack on Ukraine had highlighted how dependent and vulnerable Europe had been to supplies from an authoritarian regime with vast energy resources. In recent decades, China has built up a similarly dominant position in a number of value chains that will be central to a climate-neutral economy. This development has led to a shift from increased globalisation to what is often referred to as "derisking", where Western economies will build up their own supply chains in strategic areas. The US Inflation Reduction Act, which subsidises green industry, came into force at the beginning of 2023. For the EU, the development means that the green transition is being further accelerated, where an already high level of ambition has been strengthened with a security policy dimension. The EU's objectives centre around faster development of renewable power and the flexibility solutions that can eventually replace the role of gas in the power system, as well as in-house production of the minerals, metals and technologies needed for the transition. In the EU's largest economies, there are discussions about how industry can secure energy at competitive prices through a transition process defined by high uncertainty. This is a discussion that could continue in the EU even after the ongoing power market reform has been finalised.

11.2 Autumn and winter 2021/22: Protection for vulnerable consumers

In the autumn and winter of 2021/22, before Russia's invasion of Ukraine, rising energy prices were perceived as a temporary situation in the EU. Individual member states introduced various measures in response to high prices at national level, especially targeting vulnerable consumers. The Commission helped to clarify which measures would be permitted under the EU's current market and state aid rules. Despite some member states arguing in favour of changes to the pan-European energy market rules aimed at curbing prices, the Commission was reluctant to initiate reform work. Analyses from ACER and ESMA supported the Commission's arguments that the high prices reflected a well-functioning market that gave the right price signal in a situation of scarcity.

In the early stages of the energy crisis, the EU encouraged its member states to limit the scope of subsidies, mainly by targeting support programmes at vulnerable or energy-poor households. Part of the rationale for this was to avoid a major increase in demand in a shortage situation. The EU countries' support schemes are unlikely to have had a significant impact on Norwegian electricity prices in the autumn and winter of 2021/22. In Norway, as in many EU countries, support schemes for end users were introduced. The Norwegian electricity support scheme for households was presented by the government on 16 December 2021. Other examples of support aimed at vulnerable consumers in Norway include increased housing subsidies and electricity grants for students.

11.2.1 Member states' reactions

By autumn 2021, most Member States had started to introduce measures to mitigate the effects of high energy prices at national level, mainly in the form of temporary measures aimed at protecting

as explained in chapter 6.1.3. The difference is usually that the contract price is not market-determined in the same way as similar agreements in the futures market (market-based agreements do not normally contain any elements of subsidisation) and that the duration is often longer. A PPA can be understood as a market-based CfD.

vulnerable consumers. Some member states, including France and Spain, suspected market failure or inappropriate power market design, and argued for reform of the pan-European market rules as early as autumn 2021. Others, including Germany, warned against initiating major regulatory changes in what was perceived as a temporary crisis situation. Furthermore, Poland in particular showed strong concern about Russia's power over European gas prices, as well as possible manipulation of CO_2 prices. Poland, together with the Czech Republic, asked for the EU ETS to be suspended in response to the high energy prices. In the EU, a political divide emerged between southern European countries that wanted to intervene in the market to a greater extent, and northern European countries that wanted to wait and see and avoid disrupting market signals. The increased CO_2 prices were mainly a concern for the Eastern European countries with the largest share of coal in the power mix.

11.2.2 The Commission's assessments: Toolbox

On 13 October 2021, the Commission presented a communication called the Toolbox. In it, the Commission explained its understanding of the situation in the energy markets and predicted that energy prices would remain high through winter 2021/22 and then fall from spring 2022. Furthermore, the Commission pointed to various measures against the effects of high energy prices that member states could consider introducing at national level, without the measures risking contravening applicable EU rules. Examples of such measures are the reduction of taxes and charges in the energy sector and temporary financial support to vulnerable or energy poor households. Support of a general nature, which helps all energy consumers, does not constitute unlawful state aid. The Commission pointed out that such non-selective measures may take the form of generalised reductions in taxes and charges, or a general reduction in the rate of supply of energy products. Aid to industry that is targeted at specific sectors or companies is more strictly regulated under EU state aid rules, in order to avoid distortion of competition in the internal market. However, the Commission points to certain circumstances where targeted aid to industry can be authorised. Otherwise, the Commission encourages member states to facilitate the increased use of PPAs (fixed price agreements) between companies and power producers as a measure to achieve stable end-user prices for businesses. In addition, the Commission asked ACER and ESMA, the EU's energy and market surveillance agencies, to investigate the energy markets and the CO_2 market, respectively, to identify possible market failures or manipulation.

ACER and ESMA reports on the energy and CO markets$_2$

At the request of the Commission, ACER and ESMA delivered their first interim reports on energy markets and the CO_2 market in November 2021 (ACER 2021, ACER 2022, ESMA 2021, ESMA 2022). The interim reports were followed up with more detailed analyses in spring 2022.

ACER's findings: In its first interim report of November 2021, ACER pointed to global gas prices as the main reason for the high gas and electricity prices in Europe. The CO_2 price had also risen during 2021, but to a much lesser extent than the gas price, and the impact of the CO_2 price on electricity prices was also smaller than the impact of the gas price. Power prices varied between different member states, but those countries with a higher share of gas in the power mix, combined with low power exchange capacity, stood out as more vulnerable than others. ACER found no basis for concluding that Gazprom had engaged in illegal market manipulation, although it was clear that the company had supplied less gas to Europe than could have been expected in a situation of high gas prices. At this point, the Commission had begun to prepare its own investigations into Gazprom's behaviour in the market.

Furthermore, ACER warned that Europe was in a very vulnerable situation ahead of winter 2021/22, as gas stocks were not sufficiently filled to cover high demand in case of a combination of a cold winter and continued low import levels. ACER therefore recommended measures to strengthen security of supply, by increasing gas imports and securing storage levels. ACER found no other signs of market failure and warned against major changes in the design of the energy markets as a result of the high energy prices. The reasoning was that the prices effectively reflected real energy shortages, and that changing the market rules to lower prices would risk worsening security of supply while jeopardising long-term goals for energy efficiency and green transition. This analysis was elaborated in the follow-up report from April 2022, and ACER's reports have long been an important reference point for the Commission and Northern European member states, which at the beginning of the energy price crisis were sceptical about changes in market design.

ESMA's findings: ESMA's reports were prompted by member states' concerns about possible speculation in the CO_2 market. In its investigations, ESMA found a clear trend towards an increasing number of participants in the CO_2 market, both allowance holders and financial actors, but considered that this development was consistent with the growth of the market and could not be seen as evidence of illegal or unfavourable speculation. ESMA explained the increase in the CO_2 price by other supply and demand factors: CO_2 prices had been rising as a result of the EU's fiscal stimulus packages during the COVID pandemic and as a result of increased climate ambitions under the European Green Deal. When energy prices began to rise in autumn 2021, demand for allowances for coal-fired power generation also increased, which even with the relatively high CO_2 price became competitive with very expensive gas-fired power. Like ACER, ESMA pointed out that the price increase in the CO_2 market was significantly lower than in the gas market. At the same time, ESMA pointed out that Article 29a of the EU ETS Directive protects against extreme price increases. This article states that the Commission shall convene a meeting with the member states to discuss possible measures if the CO_2 price has been more than three times the average price over the previous two years for more than six months. These conditions were not met in 2021/22, and the Eastern European member states that had advocated for the suspension of emissions trading in the context of the energy price crisis were not successful.

11.3 Spring and summer 2022: Securing gas supply, stabilising the economy and accelerating the green transition

Russia's invasion of Ukraine in February 2022 put Gazprom's behaviour in the European gas market in a context of aggression. Throughout 2022, Russia continued with gradual export cuts that put high pressure on energy prices in Europe, and the EU had to be prepared to deal with a possible total cut in exports from the Russian side. The EU's immediate focus was on securing gas supplies through increased imports from other trading partners and common rules for gas storage. Accelerating the development of indigenous renewable energy production became a pillar of the energy independence strategy. The level of ambition in the EU's green transition was thus not weakened by the crisis, but rather strengthened, with a clear security policy dimension. During the spring and summer of 2022, the member states were given more room for manoeuvre to support the economy in the face of high energy prices and other effects of the war in Ukraine. While pan-European measures were mainly aimed at securing energy supplies, the member states were given greater responsibility for supporting consumers at national level. At the same time, the Commission was under increasing pressure to intervene in the markets. In June 2022, the first examples of market intervention emerged, and the Commission confirmed that a reform of the pan-European electricity market rules is being launched in light of the energy crisis.

A key measure taken by the EU to secure Europe's gas supply was to set mandatory storage levels for gas stocks before the winter season. The EU's gas storage targets had a direct, price-dampening effect on wholesale gas prices in the EU countries, and may have had an indirect effect on power prices in Norway. The targets may have driven up European gas prices during the summer season when gas storage had to be prioritised over gas for other purposes, but at the same time created greater predictability that helped to mitigate the risk element and thus also price growth, especially during the winter season. In addition to the gas storage targets, the EU also adopted temporary targets to reduce total gas consumption in each member state, which may have had a further dampening effect on energy prices. Gas storage targets are not directly relevant to Norway, which is not dependent on gas storage for winter consumption, unlike many EU countries. Examples of possible, similar measures aimed at strengthening security of supply in Norway could be minimum filling requirements for Norwegian hydropower reservoirs, as well as the Norwegian proposal for a steering mechanism that was submitted for consultation on 29 June 2023. Possible price effects of such measures are assessed in Chapter 14.

Through changes to the guidelines for state aid, EU countries were given greater room for manoeuvre to support businesses. In Norway, proposals for electricity support for the agricultural and greenhouse industry were presented as early as January 2022, and schemes for electricity support for businesses and loan guarantees for electricity-intensive companies followed in autumn 2022. The fact that the EU countries themselves were given responsibility for designing support schemes at national level led to a large number of different schemes with different levels of support, which may have made it difficult to assess Norwegian companies' competitive conditions against conditions in other European countries. Germany and Sweden are the only countries, apart from Norway, that have introduced support schemes for electricity costs in the business sector in general. A number of other countries have introduced measures such as a reduction in taxes on energy consumption, similar to the reduction in the Norwegian electricity tax, and also support for other energy use, such as gas and fuel. At the same time as the scope of support to end users increased in the EU countries, energy saving targets were introduced, which helped to counteract the price-driving effect the support could have had in the wholesale market.

When the EU decided to increase the level of ambition in the green transition in response to the crisis, it did so by proposing changes to directives that are relevant to the EEA. These include increased targets in the Renewable Energy Directive and the Energy Efficiency Directive, new requirements in the Energy Performance of Buildings Directive, and new rules to ensure faster development of renewables. These measures will not have an immediate effect on electricity prices, but the long-term aim is to achieve the climate targets, secure supply and ensure reasonable prices through the transition. Once the proposals have been finalised in the EU, it must be considered whether the revised directives should be incorporated into the EEA Agreement.

11.3.1 Price drivers and measures

A relatively mild winter in Europe in 2021/22 and increased LNG imports had contributed to Europe's gas stocks holding up well throughout the heating season, even with low filling levels at the start of the winter. A stable, high level of pipeline gas imports from Norway also contributed to European security of supply. Nevertheless, the price level in the gas market was very high, with a high risk premium in the price in a situation with a greater share of LNG in the market and where European gas importers had to compete directly in an international LNG market with great uncertainty.

The Commission experienced increasing pressure from some member states to allow greater intervention in the European energy markets. Shortly before the invasion of Ukraine, Spain had written to the Commission asking for legislative changes to address the structural weaknesses in Europe's energy market in the short and long term. In the letter, Spain pointed out that the period of high prices would last longer than initially anticipated, and that a crisis response based mainly on state aid would not be sustainable for member states' budgets in the long term. Moreover, as some member states have larger budgets than others, this could lead to different levels of support for consumers in different countries. In the short term, Spain asked for a pan-European solution to "decouple" electricity prices from gas prices, for example in the form of a price cap on gas, and for the Commission to consider measures to address the very high revenues of infra-marginal power producers. In the longer term, Spain called for a European power market reform aimed at ensuring that consumers benefit more from the growing share of renewable power with low production costs, while maintaining investment incentives for renewable power. Spain's input was to be supported by France, Italy, Portugal and Greece.

On 24 February 2022, Russia launched a full-scale invasion of Ukraine, and in response to the invasion, Member States asked the Commission to present contingency plans for Europe. For the energy sector, EU energy ministers specifically asked for an update of the toolbox from October 2021 with new proposals for measures that could have an immediate impact on consumers' energy bills, proposed measures to strengthen security of supply for gas, and a plan to diversify Europe's gas imports and cut dependence on Russia, including by improving LNG infrastructure in Europe.

11.3.2 REPowerEU strategies

On 8 March 2022, the Commission presented the REPowerEU strategy. The strategy updated the toolbox from October 2021 with proposals for measures that could have an immediate impact on consumers' energy bills, descriptions of how the EU can strengthen security of supply for gas, and a plan for how the EU can become independent of Russian gas imports.

Measures with immediate effect: The Commission confirmed that the ongoing energy crisis was a situation where temporary regulation of electricity prices for households and micro-enterprises would be authorised under Article 5 of the Electricity Market Directive. Although tax policy in general falls outside the EU's competence, the Commission points out that the member states themselves have the possibility to tax companies that have received extraordinarily high revenues as a result of the crisis in order to finance support measures. The member states' revenues from the EU ETS can be used to finance measures. Furthermore, the Commission pointed out that existing state aid rules allow member states to support agriculture in the face of high energy prices, that CO_2 compensation can be used to mitigate the share of the electricity bill that is due to indirect CO_2 costs for competitive industry, and in some cases also temporary support for other types of companies - for example, support for lack of liquidity in exceptional and unforeseen situations. At the same time, the Commission announced that it will present new, temporary guidelines for state aid that will give member states additional room for manoeuvre, and that the Commission will assess the need for legislative changes to the common European electricity market rules, partly with the help of analyses from ACER.

Security of gas supply: The Commission announced in the REPowerEU strategy a legislative proposal that would set a mandatory filling rate in European gas storage facilities at the beginning of each winter, defining gas storage facilities as critical infrastructure, and that state aid would be authorised to achieve the filling rate. The Commission also announced that it would support member states in coordinating the filling of gas storage facilities and that the investigation into Gazprom's possible market manipulation would continue.

Plan for independence: In 2021, gas accounted for close to a quarter of the EU's total energy needs, and Russian gas accounted for over 40 per cent of the EU's total gas imports. Russia thus accounted for around 10 per cent of the EU's total energy needs. In the REPowerEU strategy, the Commission presented its analysis of how the EU can make itself independent of Russian imports. First and foremost, it points out that the Fit for 55 package for green transition could reduce the EU's total gas consumption by around 30 per cent by 2030 if adopted and implemented in full. Further cuts in gas consumption can be achieved by installing solar cells and heat pumps in buildings, as well as energy efficiency measures. The switch from the use of gas to electricity or hydrogen in industrial processes can be accelerated, and the EU can provide greater support for its own hydrogen production and related infrastructure. The development of renewable power generation will need to be accelerated, with tighter deadlines for processing licences. The Commission announced forthcoming proposals in all these areas in the follow-up to the strategy. In addition, the Commission will continue dialogues with other trading partners on increasing gas imports to replace Russian volumes, and support investments in the infrastructure needed to increase imports from countries other than Russia.

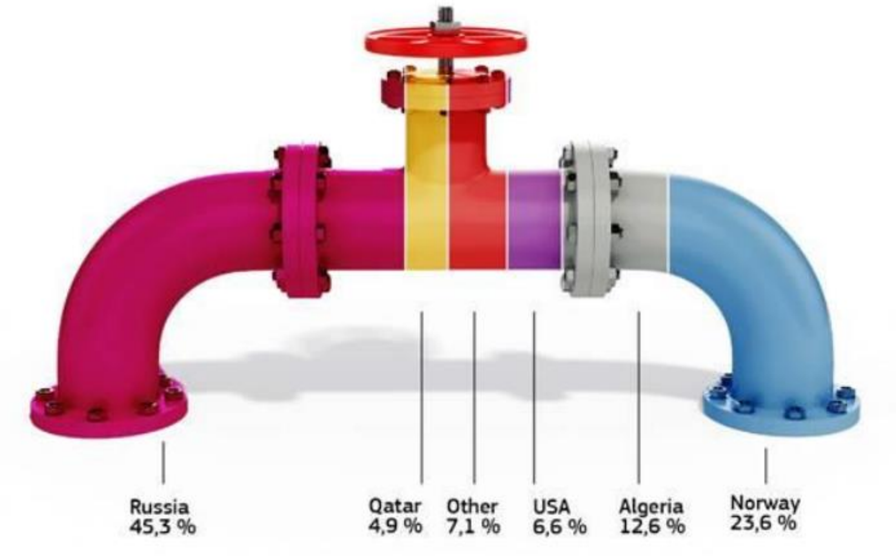


Figure 11- 1 Exporting countries' share of EU gas imports in 2021 (Europakommisjonen 2022)

The figure shows the largest exporting countries' share of EU gas imports in 2021, before the war in Ukraine. Russia, Algeria and Norway mainly supply pipeline gas, while Qatar and the US supply LNG. Due to the permanent infrastructure, pipeline gas can only be sold to Europe, while LNG can be sold to the highest bidder in the global market.

11.3.3 Follow-up of the REPowerEU strategy

23 March 2022 saw the first part of the follow-up to the REPowerEU strategy. The Commission presented new guidelines for state aid and a legislative proposal for mandatory filling levels in Europe's gas storage facilities. In addition, a short memo was presented to the member states in which the Commission discusses the pros and cons of a number of major interventions in the energy markets.

New guidelines for state aid (TCF): The new, temporary guidelines for state aid in times of crisis, called the Temporary Crisis Framework for State Aid (TCF), give member states greater room for manoeuvre to support businesses in the face of high energy prices and other effects of the war in Ukraine. A greater degree of direct aid is authorised for companies in agriculture, fisheries and aquaculture. For companies in these sectors, there was no requirement to relate the support to increased energy prices, as they were considered particularly vulnerable to the effects of the war and related sanctions. For other parts of the business sector, government loan guarantees were opened up, which can help to ensure access to loans. Member states were also given the opportunity to partially compensate businesses for increased energy prices, especially energy-intensive businesses. In its previous communications, the Commission had highlighted opportunities to provide state aid within the current rules, with a particular focus on households and small businesses. With the presentation of the new guidelines, the Commission went further in recognising the business community's need for a higher level of support, as well as the member states' need for increased room for manoeuvre to mitigate the effects of the war on the economy. When presented, the guidelines were only intended to apply until 2022, but were later extended and prolonged.

Mandatory gas storage: As a measure to strengthen the security of gas supply, the Commission presented an ordinary proposal for legislative amendments to the Security of Supply Regulation and the Gas Market Directive. The amendments propose a mandatory fill rate in EU gas storage facilities of 80 per cent by 1 November 2022, and thereafter 90 per cent by 1 November each year until 2025. Furthermore, it is proposed that storage operators in the EU must be certified by the member states in which they operate. The member states must then assess, among other things, whether the operator may have a high risk of not meeting the storage obligations. This came in response to the fill rate in Russian-owned gas storage facilities in the EU, which in 2021 and 2022 had a far lower fill rate than other storage facilities. The mandatory storage level only applies until 2025.

Communication on market intervention: Alongside the TCF and the legislative proposal on mandatory gas storage, the Commission also presented a short communication discussing the pros and cons of a number of proposals for temporary interventions in energy markets that had been put forward from various quarters. The note can be understood as a response from the Commission to those member states pushing for stronger intervention in the markets, as it came ahead of the summit between EU heads of state and government on 24-25 March 2022. Proposals under discussion include a state-owned retail company to cap retail prices for households, various forms of price caps in combination with compensation to affected actors, a revenue cap for infra-marginal power producers, a general price cap on gas across the EU, and the possibility to negotiate agreements for affordable gas imports from countries other than Russia. The Commission comments that it is very demanding to identify interventions that have the same effect in all member states and do not create distortions of competition in the internal market, and that do not have disadvantages in the form of high public expenditure or risks to security of supply. The Commission reiterates that scarcity in the gas market is the fundamental cause of high energy prices, and that diversification of imports and gas storage will be important in the coming years. It is again announced that the Commission will consider whether it is appropriate to propose legislative changes to the pan-European electricity market rules that can eventually help to deliver on the EU's energy policy goals of energy security, affordable prices and climate neutrality.

Gas diplomacy and ruble requirements: The Commission followed up on dialogue with other trading partners to increase gas imports from other countries to replace Russian volumes. On 25 March 2022, US President Biden visited Brussels and, together with the Commission, published a joint plan for strategic energy cooperation. Among other things, the plan aims to increase Europe's imports of US LNG by 2030. Just prior to the meeting, Russian President Putin had announced that "non-friendly countries", including all EU countries, would have to start paying for gas imported from Russia in roubles. The rouble requirement was criticised as a breach of contract and was not widely followed by European players.

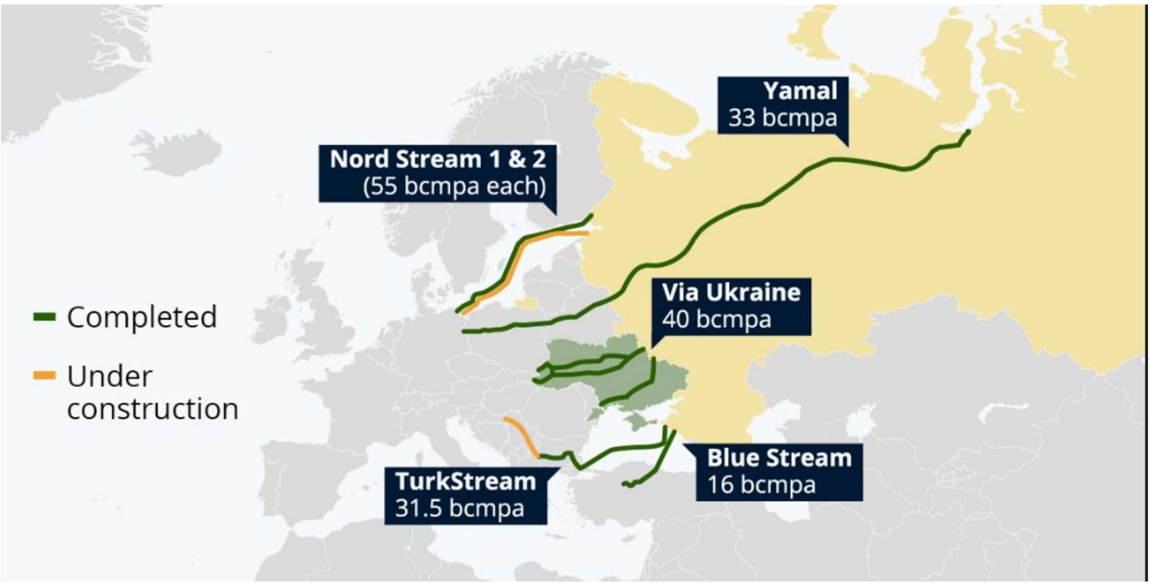


Figure 11- 2 Map of Russian gas pipelines to Europe (Source: Statista.com 2021)

The image shows pipelines for export of Russian gas to Europe. LNG imports largely come in along the coast of Western Europe, while Russian pipeline gas comes in from the east. When Poland and Bulgaria, as the first two member states, had their gas supply cut off by Gazprom in April 2022, the European gas transport infrastructure and cooperation on security of supply ensured that the countries could receive gas from their European neighbours. Later in 2022, the opening of the Baltic Pipe between Norway and Poland would further strengthen Poland's security of supply.

REPowerEU plan: The Commission's further follow-up of the REPowerEU strategy from 8 March 2022 came in the form of a major legislative package presented on 18 May 2022. The package, called the REPowerEU Plan, consists of a number of communications and proposals for legislative changes. A main communication describes how the proposals contribute to phasing out the EU's fossil fuel imports from Russia through import diversification, energy savings, increased renewable energy production in Europe and targeted investments. A separate communication updates the toolbox with proposals for various measures that member states can take to mitigate prices for consumers, and also discusses how the EU can prepare for a possible total export cut from Russia and how the power market rules can be adjusted to make the market better able to handle future price volatility and an increasing share of renewable energy. Furthermore, the Commission proposes that funds from the pan-European crisis fund established during the COVID pandemic can be used to finance the REPowerEU plan. The plan also has an international dimension, with a new strategy for EU energy cooperation with third countries.

Accelerate the green transition: The Commission is clear that the green transition must be accelerated if the EU is to succeed in reducing its imports of Russian gas. The REPowerEU plan envisages a strengthening of the Fit for 55 package, in the form of proposed amendments to the Renewable Energy Directive (RED), the Energy Performance of Buildings Directive (EPBD) and the Energy Efficiency Directive (EED). The RED proposes that the EU's 2030 target for the share of renewables be increased from 40 per cent to 45 per cent, as well as measures to ensure faster processing of permits and access to land for the renewables industry. This is followed up with a recommendation to member states on the organisation of permit processes and facilitation of PPAs. The EPBD proposes targets for the installation of solar cells and heat pumps in buildings, followed up by an EU strategy for solar power that is published in a separate communication. The EED proposes that the EU's 2030 target for energy savings be increased from 9 per cent to 13 per cent, followed by a separate strategy for energy savings. The RED, EPBD and EED were already under revision when they were to be strengthened to reflect the EU's new 2030 climate targets in the Fit for 55 package. The changes in the REPowerEU plan represent a further strengthening.

The international dimension: The strategy for energy cooperation with third countries describes a changing global energy landscape, where new opportunities to produce energy will emerge along with new trade patterns and transport needs. The short-term priority is to diversify the EU's gas imports and reduce imports of fossil fuels from Russia. In the longer term, the strategy describes the possibility of new partnerships between the EU and third countries in research and innovation, and trade in clean energy goods and critical raw materials. The strategy describes how Norway has already increased its export of pipeline gas to the EU following Russia's invasion of Ukraine, and points to opportunities for further cooperation, particularly on hydrogen, carbon capture and storage and critical raw materials through a green alliance between Norway and the EU. In summary, the strategy draws the connection between the green transition and the EU's geopolitical objective of increased resilience and an open, strategic autonomy.

Further cuts from the Russian side: Three days after the presentation of the REPowerEU plan, Russia cut its gas exports to Finland. Finland had recently submitted its official application for NATO membership and had not complied with Russia's new requirement to pay for imported gas in roubles. Finland Gas TSO was able to compensate for the lost Russian volumes with increased imports through the Baltic countries. Gazprom reduced exports to Germany through Nord Stream 1 by 40 per cent ahead of the summit of EU heads of state and government on 23-24 June 2022, where member states were expected to grant Ukraine and Moldova candidate status for EU membership. On 25 July, Gazprom announced a further 20 per cent reduction, and on 19 August a full suspension of exports to Germany through Nord Stream 1 was announced. Gazprom had initially announced a three-day suspension due to maintenance needs, but exports never resumed. During the summer, Gazprom had also suspended exports to the Baltic countries, while exports to Denmark, the Netherlands, Austria, Slovakia and Italy were reduced. European gas prices reached a historic high in August 2022 due to the uncertainty created by the cuts and concerns about security of supply ahead of winter 2022/23.

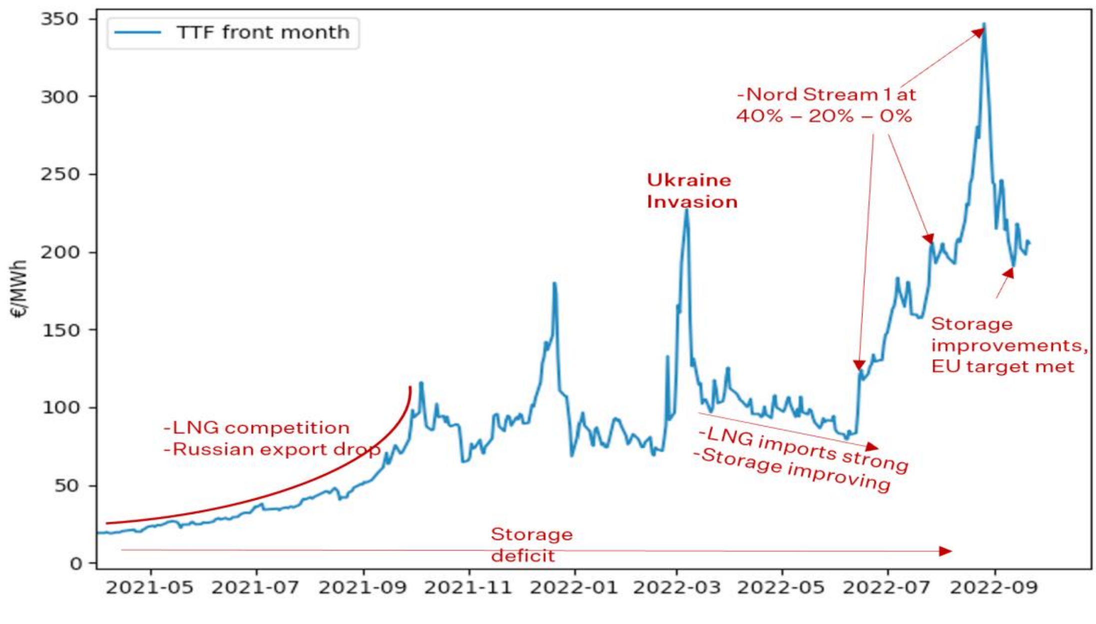


Figure 11- 3 European gas price (TTF) in the context of cuts in Russian gas exports (Source: ICE, Volue Insight)

The figure shows how European gas price increases coincide with the gradual cuts in gas exports from Russia until the end of August 2022. At the same time, a warm and windless summer affected the energy production of wind, coal and nuclear power in Europe, thereby limiting the supply of alternatives to gas power.

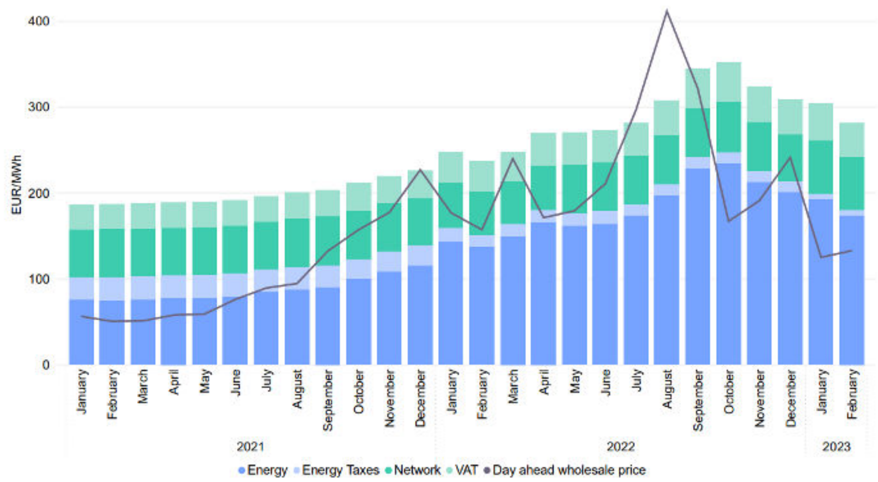


Figure 11- 4 Average day-ahead spot price and retail price for electricity in EU27 (ACER 2023)

The figure shows that European spot prices for electricity were also at their highest in August 2022, with a delayed impact on the retail price in the following months. The line shows the average day-ahead spot price, and the bars show the average retail price with the various components of the retail bill.

11.3.4 Structural changes and the winter preparedness plan

Structural market changes, Iberian gas price cap and Greek reform proposal

On 8 June 2022, Commission President von der Leyen confirmed that the Commission would start work on a reform of the EU's electricity market rules in a speech to the European Parliament. This represented a change in the Commission's position, which had previously warned against greater market intervention. Now von der Leyen described a market system that is no longer adapted to the reality of a market with a growing share of renewable energy, and that temporary crisis measures will not address the structure of the market. The statements reflected input from member states such as Spain, France, Italy, Portugal and Greece, which had previously called for structural market changes. The confirmation of the power market reform came on the same day that the Commission authorised an intervention in Spain and Portugal's wholesale market. The 'Iberian mechanism' was effectively a regional gas price cap, which would limit the impact of gas prices on electricity prices by allowing state subsidies to gas-fired power plants to be passed on to end users. The Iberian Peninsula is relatively isolated from the rest of the European electricity market due to limited transmission capacity, which played a role in the Commission's decision. The lower, subsidised electricity price in the Iberian Peninsula leads to associated neighbouring countries wanting to import more, so that Spain and Portugal are effectively subsidising their neighbours as a consequence of the measure. Exports from Spain to France increased as a result of the measure, but because the exchange capacity between the two countries is limited, this effect was also more limited than it would have been in other European countries. Prior to the meeting of energy ministers on 26 July 2022, Greece submitted a proposal outlining how the wholesale market can be split between power plants that can produce on demand and power plants that can only produce on availability to achieve lower electricity prices (discussed in more detail in 11.4).

Winter preparedness plan and first update of TCF

On 20 July 2022, the Commission proposed a Winter Readiness Plan for coordinated reduction of gas consumption in the EU, as well as an update of the Temporary State Aid Guidelines (TCF), reflecting the objectives of both the REPowerEU plan and the Winter Readiness Plan. The regulation setting targets for the reduction of gas consumption was presented as a temporary emergency regulation based on Article 122 TFEU, which allows for a fast-track process whereby member states in the Council can adopt measures without the participation of the European Parliament. A political prerequisite for this rapid but less democratic process is that the measure must be of temporary duration.

When the winter preparedness plan was presented, Russia had cut its gas exports to the EU by around 30 per cent. The plan included a proposal for temporary crisis regulations with the aim of reducing member states' gas consumption by 15 per cent. The reduction in consumption was intended to help limit costs and risks in the event of continued, or total, cuts by Russia. The 15 per cent target is initially non-binding, and the member states can largely decide how to achieve it at national level. If a very serious security of supply situation arises, the Commission may propose that the target becomes binding. The gas consumption reduction target was initially intended to apply only to the winter of 2022/23, but was later extended to apply to the coming winter of 2023/24.

Together with the presentation of the Winter Preparedness Plan, the Commission presented an update of the Temporary State Aid Guidelines (TCF) to reflect the objectives of the REPowerEU plan and the Winter Preparedness Plan. This gave member states more room for manoeuvre to support the acceleration of the green transition, for example through support for the development of renewable electricity and alternative gases such as hydrogen and biogas, and support for electrification, hydrogen capture and energy efficiency in the industrial sector. Member states were also given the opportunity to support those affected by measures to secure gas supplies, for example by providing support to companies affected by the consumption reduction targets, to replenish gas stocks or, in some cases, support for a temporary switch to more polluting fuels such as oil or coal.

11.4 Autumn and winter 2022/2023: Crisis intervention in the energy markets

In the autumn and winter of 2022/23, the EU introduced a number of temporary crisis measures in the energy markets. Several of these were introduced on the basis of Article 122 of the TFEU, which authorises a process whereby rapid decisions can be taken in the Council. During the same period, the Commission was under strong pressure from member states to introduce a European price cap on gas. This proved difficult to implement without jeopardising security of supply in a situation where high energy prices were driven by shortages in the gas market. At the same time, the Commission had recently reversed its position on whether a long-term power market reform should be implemented, and began work on preparing proposals for changes to the EU's common power market rules to be presented in the new year 2023.

Regulations based on Article 122 of the TFEU are not considered EEA-relevant, but Norway has nevertheless introduced similar measures in some cases. The Norwegian high price contribution is an example of this, as it, like the EU's revenue cap for inframarginal power producers, is a temporary measure that targets the high profits earned by some power producers during the crisis. The taxation of these revenues will provide the state with resources to mitigate electricity bills for end users through redistribution, but may also affect power producers' investment signals. In addition to the revenue cap, the EU countries required fossil fuel companies to pay an additional contribution to the member states and introduced targets for the reduction of total electricity consumption. These measures have not been mirrored in Norway. In November 2022, the Commission presented a proposal for a correction mechanism in the gas market that limits price differences between the EU and competing import markets. This has not been relevant in Norway, which is not a gas-importing country. Nor has the EU's price cap in the gas market had any significant effect on electricity prices, either in the EU countries or in Norway, as the price level that sets the threshold for the mechanism to take effect was set so high that it has never been reached since the measure was introduced.

11.4.1 Price drivers and measures

Possible interventions in the energy markets: On 7 September 2022, the Commission shared its input on further measures that could be introduced in the EU. In a separate statement, the President of the Commission mentioned the possibilities of 1) introducing pan-European targets for reducing electricity consumption, especially targeting the hours with the highest electricity prices, 2) collecting government revenues from power producers with low production costs and 3) from those fossil fuel companies that had received extraordinarily high revenues as a result of the crisis, 4) helping energy companies that had experienced liquidity problems as a result of the crisis, and 5) introducing a price cap on Russian gas. This came as a proposal to the member states two days before an extraordinary meeting of energy ministers.

The energy ministers' reactions: When EU energy ministers discussed the topic on 9 September, there was agreement to proceed with the Commission's first four proposals. The proposal for a price cap on Russian gas was far more controversial. At this point, after the Russian export cuts during the spring and summer, Russian gas accounted for around 9 per cent of the EU's gas imports. The countries that still received Russian gas feared that Russia would react to such a targeted price cap as if it were a sanction, and respond with a total export cut, so that the price cap would not help to dampen European energy prices. The Commission was aware of this risk, and had justified the proposal with the effect it would have had on limiting Russia's income from gas exports to Europe. A large number of member states also put pressure on the Commission to prepare a proposal for a price cap on gas that could have a dampening effect on energy prices.

State of the European Union 2022: On 14 September 2022, Commission President von der Leyen addressed the European Parliament in her annual State of the European Union address, which focused on the war in Ukraine and the subsequent energy crisis. Von der Leyen gave an account of the situation in the European energy market, where Norway was mentioned as a reliable supplier of gas in the EU's work towards energy independence. The establishment of a separate working group between Norway and the EU on gas supply was announced. Von der Leyen also presented a legislative proposal for temporary crisis regulations that followed up on the four above-mentioned points that the EU energy ministers were able to agree on. In addition to the Temporary Crisis Framework, the Commission President announced further changes to the State Aid Guidelines and addressed the Commission's ongoing work on the preparation of a long-term power market reform, which she described as deep and comprehensive. Von der Leyen pointed to a power market design that can no longer be justified to consumers and the need to decouple gas and electricity prices to ensure that consumers can benefit more from renewable power with low production costs. Again, her statements reflected concerns that had previously been raised by countries such as France, Spain, Italy, Portugal and Greece.

Legislative proposal on temporary market intervention: At the same time as von der Leyen's speech to the European Parliament, the Commission's legislative proposal on temporary interventions in the energy markets was presented. The legislative proposal came in the form of a temporary crisis regulation, and included targets for coordinated reduction of electricity consumption in the EU, a revenue cap for infra-marginal power producers with a requirement for redistribution to end users, a mandatory solidarity contribution from the fossil fuel sector, and a temporary extension of the possibility of offering regulated electricity prices. To help energy companies that had experienced liquidity problems as a result of the crisis, forthcoming amendments to the Temporary State Aid

Guidelines were announced, as well as further work in DG FISMA in cooperation with ESMA. No legislative proposal for any form of price cap on gas was presented.

Coordinated reduction of electricity consumption: The electricity consumption reduction target was twofold, with a non-binding target of a 10 per cent reduction in total consumption and an additional binding target of a 5 per cent reduction in consumption during the hours when electricity prices are at their highest. As gas-fired power is often used to meet demand during the most expensive hours, the idea was that the binding target could help both to reduce average electricity prices and to save gas before winter. Member states were largely left to decide how to achieve the targets at national level.

Revenue cap and solidarity contribution: A temporary revenue cap of EUR 180/MWh was set for infra-marginal power producers, and member states had to ensure that revenues above the cap were redistributed from power producers to end users. Member states could also choose to introduce stricter revenue caps at national level. In addition, coal, oil, gas and refinery companies were required to pay a solidarity contribution to the member states, corresponding to 33 per cent of extraordinary profits earned in 2022. The solidarity contribution was intended to strengthen member states' ability to support end users through the crisis. These two measures are similar to taxation, which in principle is not an EU competence, but which in this case was nevertheless approved by the Council on a temporary basis.

Regulated retail prices: It was clarified that the temporary possibility for member states to offer regulated retail prices applies to SMEs in addition to households and microenterprises, and furthermore that the regulated prices can be set below cost price as long as the state compensates the electricity suppliers for the difference between the purchase price in the wholesale market and the regulated retail price, and ensures that all electricity suppliers have equal opportunities to offer regulated prices.

The Nord Stream explosion: On 26 September 2022, German authorities reported a rapid pressure drop in Nord Stream 1 and 2, two parallel gas pipelines built to deliver Russian gas to Germany through the Baltic Sea. Soon after, three gas leaks were reported from the pipelines in the Swedish and Danish parts of the Baltic Sea. Investigations revealed that the leaks were caused by explosives detonated near the pipelines at a depth of 80 metres in a sabotage operation. Nord Stream 1 was completed in 2011, but had not delivered gas since Russia cut all exports to Germany at the end of August 2022. Nord Stream 2 was recently completed, but had never delivered gas. Both pipelines contained pressurised gas, which caused the leaks in the Baltic Sea and the pressure drop on the German side after the explosion. Although the pipelines did not deliver gas, the incident led to a jump in European gas prices. This can be explained by the fact that the incident confirmed that no Russian gas would flow to Germany again anytime soon, and furthermore by concerns about the security of Europe's energy infrastructure.

Temporary emergency legislation on measures in the gas market: On 18 October 2022, the Commission presented a series of legislative proposals on gas market measures, based on Article 122 TFEU. The measures concerned better coordination of member states' gas purchases, mitigation of volatility in the gas market, and the creation of new solidarity agreements between member states in the event of an emergency situation in individual countries or regions. This package of measures also did not include proposals for price caps on gas, but the Commission announced ongoing work to ensure that European importers do not pay an unnecessarily high price for LNG. In addition, the Commission presented a Council recommendation on securing critical infrastructure as a result of the Nord Stream explosion. The measures were adopted in December 2022 with a duration of one year until December 2023.

Coordination of gas procurement: The proposed legislation on better coordination of gas procurement was intended to prevent member states from driving up European gas prices by outbidding each other, strengthen the negotiating positions of the players, and achieve lower prices for imported gas without jeopardising security of supply. European buyers are given the opportunity to report expected gas demand to an EU platform, and then to buy gas from the platform. Participation in the scheme is voluntary, but member states must ensure that demand equivalent to at least 15 per cent of the EU's storage needs is reported. Operators who choose to participate in the scheme are given the opportunity to form a purchasing consortium, where several can join forces to negotiate gas contracts with the supply side.

Dampening volatility in the gas market: To mitigate volatility in the gas market, the Commission proposed to introduce a brake on intraday trading of energy derivatives, to avoid speculation leading to large price fluctuations during a single trading day. Furthermore, the Commission announced forthcoming measures to ensure that European importers do not pay more than necessary for LNG. European LNG contracts are often linked to prices on the Dutch gas trading market TTF, which is the most liquid market of its kind in Europe, but TTF prices can be volatile. Therefore, the Commission wanted to develop an alternative, more stable reference price for LNG contracts, which would better reflect real European demand without being influenced by speculation. In anticipation of such an alternative reference price, which would take time to develop, the Commission announced that it could propose a temporary "price corridor" for trading on the TTF to ensure that LNG prices are as low as possible without jeopardising security of supply.

New solidarity agreements: In order to strengthen solidarity between member states in the event of emergencies, mandatory minimum standards for solidarity agreements between countries are proposed. The Regulation on security of gas supply already allows for this type of solidarity agreement, but this has been voluntary and very few member states had designed and signed such agreements before the energy crisis. In addition, the Commission proposes detailed rules for how gas should be distributed between member states in the event of an emergency.

11.4.2 EU leaders' reactions

The Commission's proposal for temporary crisis measures in the gas market was discussed at the summit of EU heads of state and government on 20-21 October 2022. Here, the Commission received the support of the EU leaders to implement the proposed measures in cooperation with the Council, and to continue working on the proposals to mitigate volatility in the gas market. In addition, EU leaders made further requests for proposals from the Commission, on two points in particular:

Decoupling of gas and electricity prices: The EU leaders conclude that more should be done to decouple electricity prices from gas prices, and ask the Commission to present a proposal for a possible price cap on gas for power generation, similar to the Iberian model. At the same time, the EU leaders point out that it must be avoided that such a price cap leads to increased gas consumption in the EU, or that the price cap has an uneven impact on the budgets of the various member states, or that subsidised power disappears to third countries outside the EU. The Commission responded with a note explaining the risks of extending the Iberian mechanism to cover the entire EU, and instead outlines other, less intrusive measures to address the influence of gas prices on electricity prices.

Accelerate renewable energy deployment: EU leaders want to accelerate the deployment of renewables in the EU, including through temporary emergency measures under Article 122 TFEU. As part of the REPowerEU plan from spring 2022, the Commission had already put forward proposals for changes to the Renewable Energy Directive to help speed up deployment. One challenge was that the Renewable Energy Directive was already undergoing a major revision as part of the Fit for 55 package, and that the process of finalising the regulations was slow due to the many elements under negotiation. The EU leaders then proposed that temporary measures could be introduced pending the finalisation of the revised Renewable Energy Directive.

Examples of disadvantages of different forms of price caps on gas

Price cap on Russian pipeline gas: One of the Commission's early suggestions was to introduce a price cap that would only apply to Russian pipeline gas, in order to limit Russia's revenue from the remaining gas exports to Europe. Russia has limited opportunities to export this gas to other markets. The downside of such a measure was the risk of a total export cut from the Russian side, which Russian President Putin had threatened on the same day that Commission President von der Leyen mentioned the proposal in September 2022. A total export cut would have led to higher gas prices in Europe, and would have been particularly demanding for the security of supply in those member states that still received Russian pipeline gas. In addition, the measure could in practice resemble a sanction, which would require unanimity in the Council. A price cap on Russian pipeline gas was not implemented.

Price cap on all gas transactions in the EU: A group of 15 member states launched the proposal to put price caps on all gas transactions in the EU, including all imports. The disadvantages of this are many. The measure would have conflicted with contractual relationships with third countries and restricted the flow of gas within the EU. The measure would have required the creation of a separate EU regulator to replace the market and organise the distribution of gas between member states and different consumer groups. In addition, the EU could have been outcompeted in the global LNG market, which in turn would have exacerbated the shortage in the market. Drastic measures to reduce consumption would be necessary to counteract higher demand as a result of lower prices, which in practice resembles rationing. A price cap on all gas transactions in the EU was not implemented.

The Iberian price cap: EU heads of state and government pointed to the possibility of introducing a European price cap on gas for power generation along the lines of the Iberian model, in order to decouple gas and power prices in Europe to a greater extent. The disadvantage of this is the high costs it would entail for member states that have to subsidise gas power. When power is sold at a lower price, there is also a risk that subsidised power will disappear into trade with associated third countries, meaning that the EU is effectively subsidising its neighbours. When Spain and Portugal were approved a price cap according to this model in June 2022, part of the Commission's justification was that the countries have relatively limited physical connections to their neighbouring countries. Furthermore, the subsidised energy could lead to increased demand for both gas and electricity. A price cap according to the Iberian model was not introduced at European level.

Limiting LNG costs: As Russia gradually reduced its gas exports to Europe, increased LNG imports became essential to secure supply and replenish European gas stocks. For the Commission, it was essential to avoid measures that would limit the ability of European importers to attract LNG cargoes to Europe by outbidding competitors in the global market. However, some member states were concerned that European importers were bidding higher than necessary in the face of global competition. Therefore, a comparison of price levels in the European market and competitor markets was requested, as well as measures that could help minimise the cost of LNG. This was followed up in legislative proposals from the Commission in October and November 2022. The downside was that the measure that was to be introduced only facilitated a marginal dampening of the gas price and did not respond to the higher expectations of the member states.

The discussion on a new EU fund: Some member states and the French and Italian Commissioners advocated for a new EU fund based on shared loans, inspired by the fund established to support the

European economy during the COVID pandemic. The argumentation was that member states with larger government budgets and lower debt-to-GDP ratios would benefit from the temporary state aid guidelines and have access to affordable loans if needed, while countries with smaller government budgets and higher debt-to-GDP ratios would not have the same ability to finance support measures at the national level. The EU as a bloc has a strong credit rating and the ability to raise joint loans that can be redistributed to member states, as was the case during the COVID pandemic. By autumn 2022, Germany had signalled plans to raise a separate loan to finance support measures at national level, but at the same time opposed the idea of a pan-European fund based on loans. This position was poorly received by the other member states. EU leaders were unable to agree on a way forward at the summit on 20-21 October, although the issue was raised.

Other updates to the Temporary State Aid Guidelines (TCF): On 28 October 2022, the Commission presented an update of the TCF, which essentially extended the duration of the temporary rules by one year to 31 December 2023 and increased the ceiling for aid to industry. In addition, the guidelines opened up for support for liquidity in the energy sector, and for support to actors affected by the electricity consumption reduction targets.

Proposal for a temporary emergency framework to accelerate the deployment of renewable energy: On 9 November 2022, the Commission responded to EU leaders' call for a proposal for a temporary emergency framework to accelerate the deployment of renewable energy. The measures mainly consist of tighter deadlines for authorisation processes and easier access to land. The proposal came in anticipation of the finalisation of the Renewable Energy Directive, where the same measures had been proposed on a permanent basis under the REPowerEU plan. The temporary regulation was adopted in December 2022 and was given a duration until June 2024.

Proposal for a temporary crisis regulation on a correction mechanism in the gas market: On 22 November, the Commission presented a legislative proposal, based on Article 122 TFEU, which was the result of a long discussion with member states on a possible price cap on gas. This came in the form of a temporary "correction mechanism" in the gas market, which would ensure that gas prices in Europe are not higher than necessary to attract LNG from the global market. The idea was to limit the highest price spikes, while ensuring that European importers are still able to offer an attractive price to LNG exporters. The mechanism will be activated if European gas prices (TTF month ahead) are higher than EUR 180/MWh within three days and at least EUR 35/MWh above the global LNG price during the same three days. The price cap is intended to ensure that European gas prices do not rise unnecessarily high in situations of market scarcity. Since there is no single global LNG price but rather different prices in different regional markets, ACER is tasked with developing a reference price based on the gas prices in the main competitor markets including Asia and the UK. When the correction mechanism was presented, TTF month ahead prices were around EUR 70-80/MWh, far from the EUR 180 threshold that would have triggered the mechanism. The Commission described the proposal as a "dynamic price corridor". The temporary regulation was adopted on 22 December 2022 with a duration until February 2024, despite mixed reactions, especially from those member states that had initially wanted stronger intervention in the market.

11.5 Spring and summer 2023: Long-term power market reform and global competitiveness

At the start of 2023, the US Inflation Reduction Act (IRA) came into force. The US budget package included significant subsidies for green industry, which raised concerns in the EU about Europe's competitiveness in the green transition. In February 2023, the EU's Green Deal Industrial Plan was launched in response to the US IRA and a changed global context for industrial and trade policy. Member states were given new opportunities to support strategically important industries, in addition to existing opportunities to mitigate the effects of high energy prices. Different levels of support in different member states made it difficult to assess possible distortions of competition in the internal market. When the power market reform was presented in March 2023, it was also seen in the context of the EU's green industrial plan. Negotiations on the reform are still ongoing in the Council and Parliament, where key debates have centred on the extent to which member states should be able to control investments and redistribution in the market. In parallel with the EU, the UK initiated work on its own long-term power market reform. The measures have many similarities with those that have been discussed between EU countries, but in the UK, no legislative changes have yet been proposed.

The EU's power market reform consists of amendments to directives that are considered EEA-relevant and must be considered for incorporation into the EEA Agreement. Although the reform has not been finalised, it is clear that the EU will retain marginal pricing in the wholesale market. Changes to the basic pricing mechanism were not proposed by either the Commission or the Parliament, and have not been part of the Council's ongoing discussions. Among the proposed legislative changes, measures to strengthen the uptake of PPAs and fixed price agreements could be positive to mitigate price volatility for both producers and consumers. If the EU countries succeed in developing their own flexibility solutions in line with the objectives proposed in the reform, this could have a dampening effect on the price level in Norway (see Chapter 12). It is uncertain what the rules for organising state CfD schemes will ultimately look like - these may open up new room for manoeuvre to support consumers, particularly in the business sector, but if they lead to different schemes in different countries, they may also have competition-distorting effects. The need for industrial power schemes is being discussed in several EU countries. If these discussions lead to regulatory changes, in or independently of the power market reform, this could also give Norway greater room for manoeuvre. In the UK, the reform work has not progressed as far as in the EU. Of the measures being discussed in the UK, the introduction of more bidding zones in particular could have an effect on the price level in Norway through international trade. Whether this could have a price-dampening effect will depend on the power balance in the various UK bidding zones and how this develops in the long term in relation to the Norwegian power balance (see chapter 12).

11.5.1 US Inflation Reduction Act (IRA)

The US IRA budget package was passed in August 2022 and came into effect in January 2023. The package will mobilise USD 738 billion for health, green investments and reduction of national debt through tax reform. The EU's concern is that the IRA will pull green investments out of Europe to the US, in a situation where the European economy is already under pressure. At the summit on 15 December 2022, EU leaders stressed the importance of an ambitious industrial strategy as a basis for the green transition and to reduce import dependencies. The Commission was asked to present measures to strengthen Europe's competitiveness in light of the energy crisis and the current global context.

11.5.2 EU's Green Deal Industrial Plan

On 17 January 2023, the Commission responded to the EU leaders' request with the Green Deal Industrial Plan, which announces measures to strengthen the EU's competitiveness, referring to the US IRA, but also to other countries that have strengthened their industrial policy with a view to green transition. China's long-term industrial and trade policy is emphasised as a particularly big challenge for European industry. The plan announces that member states will first be given greater room for manoeuvre to provide state aid to strategically important industries, before the Commission will follow up with a legislative proposal for a pan-European fund for strategic investments. Separate initiatives will ensure the EU's capacity for industrial production and extraction, processing and recycling of critical raw materials, as well as strengthening expertise in key fields. The Commission points out that measures under the REPowerEU plan are already facilitating the acceleration of the renewables deployment that will be necessary to ensure industrial competitiveness. Furthermore, the upcoming power market reform can help to ensure lower and more predictable prices from renewable energy, for example through various forms of long-term contracts. In this way, the upcoming power market reform, which was initially motivated by the energy price crisis, was placed in the context of the ongoing project to strengthen Europe's competitiveness in a new global context.

11.5.3 State aid in crisis and restructuring (TCTF)

As announced on 9 March 2023, the Commission presented new, temporary guidelines for state aid in crisis and transition (TCTF), which build on and replace the TCF. Whereas the TCF was aimed at support for high energy prices and other effects of the war in Ukraine, the TCTF also allows for support for restructuring in the context of the EU's response to the US IRA. The TCTF reflects the objectives of the EU's Green Deal Industrial Plan and gives member states greater room for manoeuvre to match US subsidies to avoid investments being moved out of Europe. The guidelines aimed at restructuring will last until 2025, while those aimed at high energy prices will last until 2023. In addition, changes were made to the General Block Exemption Regulation (GBER), which reflects the EU's goal of green and digital transformation. The changes to GBER also clarify the member states' temporary ability to regulate energy prices for SMEs.

In Norway, a loan guarantee scheme for businesses was introduced and fixed price agreements for electricity were facilitated through a temporary change in the resource rent tax for hydropower.

11.5.4 Different approaches to state aid in different member states

When Vice President Vestager presented the TCTF in February 2023, she used the word "temporary" 14 times about the new guidelines, emphasising that the use of state aid to establish industrial capacity and match third countries' subsidy levels poses significant risks to the internal market. Not all member states have equal ability to offer support, and since the TCF was introduced in March 2022, France and Germany together had accounted for close to 80 per cent of the approved aid amounts. The many different national approaches to state aid have made it challenging to assess possible distortions of competition between European countries. Norway introduced a temporary support scheme for businesses for the months of October-December 2022. Since the scheme expired in December 2022, measures for businesses have largely been orientated around loan guarantees and facilitation of better fixed price agreements. Germany and Sweden's electricity support schemes for businesses are among the alternative schemes that have been raised in the Norwegian public debate.

Examples of German and Swedish support programmes that include companies

Germany's energy subsidy programme (BMWK 2022)**:** Germany's "price brake", which involves public support for end-user costs for electricity, gas and district heating, entered into force on 1 March 2023, having been formally approved by the Commission on 21 December 2022 (European Commission 2022). A temporary scheme is planned to last until April 2024, with retroactive effect for January and February 2023. The scheme is partly financed with state revenues from the EU-required revenue cap for inframarginal power producers, and partly with other funds from the state budget. The Commission's authorisation of the German scheme is currently only valid until 2023, based on temporary state aid guidelines that expire in the same year. The revenue cap for inframarginal power producers is currently only required until June 2023. The planned duration until April 2024 is therefore dependent on further clarifications at European level.

The programme covers a number of end-user groups, including households, SMEs and large companies. Companies are subsidised to cover part of their costs, based on historical or projected consumption and energy intensity. Companies receiving EUR 25 million or more in support are prohibited from taking dividends and paying bonuses. The subsidy is distributed to all eligible end-users through the energy bill, with the state paying the difference between the spot price and the subsidised retail price. The subsidy mitigates only a percentage of the companies' bill, and consumption above this level is billed at the normal price.

Electricity price brake for businesses: For small businesses with annual consumption below 30,000 kWh, the support level is set at 40 cents per kWh for a volume corresponding to 80 per cent of the previous year's consumption. For medium-sized and large businesses with annual consumption above 30,000 kWh, the support level is set at 13 cents per kWh for a volume corresponding to 70 per cent of the previous year's consumption.

Gas price brake for businesses: For SMEs with annual gas consumption below 1.5 GWh, the eligible amount is set at 12 cents per kWh for a volume corresponding to 80 per cent of expected annual consumption. For larger businesses with annual gas consumption above 1.5 GWh, the support level is set at 7 cents per kWh for a volume corresponding to 70 per cent of expected annual consumption.

Support amount: Limits on support amounts per company are the same for electricity and gas support. Full support, equal to the eligible amounts described above, can amount to up to EUR 2 million. If a company qualifies for more than EUR 2 million, they will receive support for a lower proportion of consumption, and the company must guarantee that jobs are retained until April 2025. Furthermore, the company may be required to document that it is severely affected by high energy costs by showing that operating profit before depreciation and amortisation will be reduced in 2022-24 compared with 2021. Aid amounts above EUR 150 million will require an individual assessment by the Commission.

Sweden's electricity support schemes: Sweden's temporary electricity support schemes for businesses entered into force on 6 March 2023, after being approved by the Commission on 15 February 2023 (Klimat- och näringslivsdepartementet 2023, Klimat- och näringslivsdepartementet 2023).

Electricity subsidies for electricity-intensive businesses throughout Sweden: Electricity-intensive companies, where electricity intensity is defined by a consumption of at least 0.015 kWh per SEK of turnover, can apply for support for the electricity expenses they incurred during the period October-December 2022. The companies must be able to document that the price they paid for electricity during this period was 1.5 times higher than their average price in 2021. Support is provided for 50 per cent of the eligible costs. The scheme only covers companies that, according to this methodology, are entitled to at least SEK 50,000 and has a ceiling of EUR 2 million per company or approximately SEK 20 million.

Electricity support for all businesses in SE3 and SE4: Businesses in southern Sweden can apply for support for electricity consumption in 2023. The subsidy amount will be 50 øre per kWh in SE3 and 79 øre per kWh in SE4. The subsidy is calculated based on the companies' historical consumption in the period October 2021 - September 2022. This scheme also has a ceiling of approximately SEK 20 million per company. Electricity-intensive companies in SE3 and SE4 that received support for their expenses in the period October-December 2022 can apply for further support in 2023.

11.5.5 Input ahead of the power market reform

In their input to the power market reform, the member states were roughly divided into two political blocs between Northern and Southern Europe. Input from Greece, Spain and France are examples of the attitude of southern European member states, which wanted a deeper reform with major changes to the marginal pricing system. The counterweight was Germany and north-western member states, which had been more sceptical about initiating extensive reform work in times of crisis and were also concerned about the effect changes in marginal pricing could have on the efficiency of the market and the development of renewable energy in Europe. The Southern European member states supported the use of two-way CfDs between the power producer and the state, which could facilitate a redistribution of the power producers' infra-marginal revenues back to consumers to achieve retail prices that better reflect production costs in the power mix. This could be similar to resource rent taxation. One challenge raised by France in particular is that it is difficult for the state to redistribute tax revenues to all consumers, including businesses, without conflicting with state aid rules. One possible solution could have been to introduce transfers through two-way CfDs as an integral part of the power market design. Germany, for its part, has been concerned about the competitive distortions such a setup could create in the internal market, given potentially high levels of state support for both power generation and power-intensive industry.

The Greek proposal: In July 2022, Greece presented a market reform proposal outlining how the market rules could differentiate between non-regulated and regulated power to achieve lower retail prices that better reflect average generation costs in the power mix (Council of the European Union 2022). Greece argues that the current market design is not suitable for a power mix with a high and growing share of renewable power generation and that retail prices are therefore unnecessarily high. In implementing the proposed market design, Greece proposes changes to the organisation of the wholesale market so that the bidding in the day-ahead market is split into two steps. First, producers of non-regulatable power bid in volumes. For these bids, the generators are paid based on an agreed price in CfDs that can be entered into with private operators or a regulatory authority, regardless of the day ahead market price. If the producers do not have a CfD, they can participate in a publicly owned Green Power Pool, which is responsible for purchasing power and selling it to consumers. In the next step, the market operator calculates the volume needed to clear the market. Producers of dispatchable power then bid with volume and price, in the same way as the market is cleared today. The intraday and balancing markets remain unchanged. End users receive a price that reflects the average of what producers of non-regulatable power earn through CfDs or in the Green Power Pool and what producers of regulatable power earn in the spot market. Greece estimates that such a market design could reduce European retail prices by approximately 50 per cent. The proposal to split the wholesale market in two was not followed up in the Commission's proposal for power market reform, but the idea of facilitating retail prices that more closely reflect production costs was supported by some member states and was further developed by Spain and France.

The Spanish proposal: In January 2023, Spain shared its proposal for market reform, with a basic analysis similar to the Greek one. Spain argues that the current market design does not deliver stable and affordable electricity prices to consumers, nor will it do so in the future. Infra-marginal power producers receive excessive revenues at the expense of end users, and furthermore, these revenues will not incentivise investment in new power due to a number of barriers to entry. For example, the EU's potential for hydropower has already been largely developed, and major nuclear power developments are not accepted. Development of other renewable power may be possible, but not at the speed required to bring electricity prices down to average production costs. Spain also believes that there are a number of market failures that indicate that stronger political control will be necessary to ensure sufficient renewable power, as well as the flexibility solutions that will be necessary in the future power system with a greater degree of unregulated production. Unlike Greece, Spain does not propose changes to the wholesale market. Instead, extensive use of two-way CfDs between power producers and the government is proposed, where the producers are guaranteed an income while the government takes income above the guaranteed price. The guarantee price in the CfDs is determined through auctions, with the exception of certain technologies where the government should set a regulated guarantee price due to high barriers to entry. Hydro and nuclear power are mentioned as examples of such technologies. Producers of dispatchable power should be exposed to spot prices to a certain extent, to ensure production in high price hours. Finally, Spain points to capacity mechanisms as a solution to ensure investments in flexibility. According to Spain, the setup should ensure both necessary investments and lower end-user prices than the current market design provides. The suggestion to use state CfDs to achieve a greater degree of political control of retail prices was followed up by France.

Input from France: In February 2023, France shared its input with the Commission, where France, like Greece and Spain, focuses on the use of CfDs to mitigate retail prices. France points out that the current market design has served Europe well, demonstrated adaptability in the energy crisis, and guarantees optimal allocation of resources and efficient operation of the interconnectors. Nevertheless, France sees a challenge in the fact that marginal pricing means that retail prices do not reflect average production costs. France points out that end users have paid too much for electricity during the energy crisis, while there is no guarantee that power producers' exceptionally high revenues will result in investments in new production. In other situations, low electricity prices over a long period of time may result in necessary investments in maintenance of critical installations not being realised. PPAs, as they are currently designed, do not guarantee a price based on production costs and can therefore only partially address the above-mentioned challenges. France believes that those member states that wish to do so must be given the opportunity to enter into two-way CfDs with new and existing power installations, in order to ensure a retail price that reflects production costs and at the same time a predictable income for producers. The guaranteed price should be determined by the national regulatory authority. Furthermore, the state must be able to redistribute the revenues from the CfDs to end users within all consumer groups, without the transfer being defined as state aid. The input on the use of state CfDs for redistribution was to some extent followed up in the Commission's proposal for power market reform.

Input from Germany and northern member states: Germany, together with the EU's northern member states, has provided a counterweight to the southern European countries advocating for major changes to the pan-European rules for the organisation of the electricity market. The first input from these member states came in December 2021, warning against moving away from the fundamental, competition-based principles of the existing market framework. In February 2023, ahead of the Commission's presentation of its reform proposal, a new joint input was received from Germany, Denmark, Estonia, Finland, Latvia, Lithuania and the Netherlands. This again emphasises that the benefits of the current power market design must be retained, particularly the further integration of the market through interconnectors and free price formation in the wholesale market. Furthermore, incentives to invest in renewable energy must be preserved and strengthened. The countries warn against limiting the income of renewable energy producers, and point out that the EU's temporary income cap for infra-marginal producers should not be continued on a permanent basis. PPAs and some forms of CfDs can help to secure investments in the green transition and to pass on the benefits of an increasing share of renewables to end users, but CfD schemes must be voluntary, not cover dispatchable power or existing power plants, be targeted at new renewable technologies, and contract prices must be in line with state aid rules and not result in price regulation (contrary to France's proposal). Finally, it is suggested that consumer protection should be strengthened and that barriers to active customers and energy communities should be addressed.

Input from Norway: The Ministry of Petroleum and Energy has on two occasions sent published input to the Commission's work on the power market reform - in February 2023 for the Commission's consultation, and in June 2023 following the presented reform proposal. In the input from February 2023, the Norwegian authorities, like Germany and northern member states, emphasise that a well-functioning market is necessary for efficient use of resources and that any changes to the existing market framework should be thoroughly investigated. It is argued that price signals are necessary for the best possible utilisation of stored energy, including energy stored in reservoirs. It is warned that price guarantees or price caps will affect the ability of hydropower producers to allocate energy production over time, and thus entail a risk of scarcity in situations of high demand. It is therefore recommended that the expanded use of CfDs be carefully analysed with regard to possible negative effects on security of supply. In June 2023, the Norwegian authorities wrote that it is positive that it has not been proposed mandatory use of CfDs for support for dispatchable hydropower, as this is a contract form that is not well suited for this type of production. The submission also pointed out the importance of good liquidity in the spot price market and the financial markets, and that facilitation of PPAs should not be at the expense of this.

11.5.6 Proposal for power market reform in the EU

The Commission presented a proposal for power market reform on 14 March 2023. Negotiations on the reform are still ongoing. The reform consists of amendments to regulations and directives from the Clean Energy Package, mainly the Electricity Market Directive, the Electricity Market Regulation and the REMIT Regulation. All these regulations are assumed to be EEA-relevant. The reform came in two parts, with part 1 focusing on improving Europe's electricity market design and part 2 focusing on better protection against market manipulation. Although the reform work was initiated as a response to the energy crisis, it was presented at its launch as part of the EU's Green Deal Industrial Plan.

Part 1 on power market design

The Commission did not propose any changes to the basic mechanism for price formation in the European wholesale market (marginal pricing). Previous input from Greece, for example, on a possible division of the wholesale market was not reflected in the final reform proposal. Instead, the Commission's focus was on further developing the current market design with lessons learnt from the crisis and in light of the upcoming energy transition. Although the Commission has not proposed changes to price formation, other measures are proposed that can help to mitigate the impact of gas prices on electricity bills, particularly volatility. For households, this involves strengthening consumer rights and facilitating fixed price agreements, including bilateral long-term contracts with clean energy producers. Furthermore, member states will help to ensure the development of flexibility in the European power system that can eventually replace the role of gas, for example by increasing consumer flexibility and supporting new energy storage technologies such as hydrogen and batteries. In order to be able to react quickly in the event of a new electricity crisis in the future, it is proposed that the EU can declare an emergency situation so that member states are quickly authorised to implement emergency measures that would not be permitted in normal times. The input from northern member states and Germany is largely reflected in the Commission's proposal. In addition, the Commission has to some extent accommodated France and Spain with a proposal on how state CfDs can be used to pass on the low cost of clean power generation to consumers. The European Parliament has adopted its position on the changes proposed in Part 1 of the reform, but the member states in the Council have not yet agreed on their position.

Examples of legislative changes proposed by the Commission in Part 1, as well as Parliament's proposals on the same points, are:

Consumer rights: Member states must ensure that electricity customers can choose between both fixed price contracts and dynamic contracts, and electricity sales companies above a certain size must offer fixed price contracts to their customers. New requirements are set for the type of information customers should receive about the different types of contracts before a contract is entered into or extended. Customers will also be entitled to have more than one electricity contract at the same time. Member states shall ensure that electricity sales companies have adequate price hedging strategies in place to ensure that the fixed price contracts offered are financially sustainable even in situations where spot prices fluctuate. Member States shall also ensure that vulnerable customers are protected against disconnection from the electricity supply and that a provider of last resort is designated to ensure the continued supply of electricity to households that do not receive market-based offers.

In addition, Parliament proposes that price regulation should be allowed for vulnerable and energy poor households in normal times as well as in times of crisis, and changes that would further strengthen the protection of vulnerable customers against disconnection from the electricity supply.

Uptake of PPAs: The development of PPA markets varies greatly between member states, and the Commission wants to incentivise the conclusion of such agreements. Member States are given a clearer mandate to address barriers, including by ensuring that specific instruments (such as government guarantee schemes) are in place. When member states provide state aid to finance renewable energy projects, projects that provide for the sale of a share of the power generated through PPAs will be prioritised. PPAs for fossil fuel power shall not be incentivised.

In addition, the Parliament proposes standardising PPA contracts, creating a database at European level with information on existing contracts and a marketplace where demand can be aggregated, and introducing dedicated auctions at EU level to ensure that renewable targets are met.

State CfDs and redistribution of revenues: It is proposed that state support for new investments in power generation should come in the form of two-way CfDs for the selected technologies wind power, solar power, geothermal power, hydropower without reservoir and nuclear power. The reason for choosing these technologies is that they are non-fossil, low-emission technologies with low and stable operating costs, which typically do not contribute to flexibility in the power system. Technologies at an early stage of development are excluded. "New investments" shall include investments in refurbishing, upgrading or extending the lifetime of existing installations. The CfDs will set a minimum price with a revenue guarantee, but also a maximum price so that the power producer's revenues above the maximum price are repaid to the state. The state's revenue will be redistributed back to all end users, based on their share of electricity consumption. The scheme for redistribution to end users must be designed so that incentives to respond to price signals are safeguarded. The fact that such schemes will enable member states to redistribute producer surpluses from electricity producers to all end users, including businesses, has led to concerns that different CfD schemes may create unequal conditions of competition between member states in the internal market. In the Council, this point has been the most difficult to agree on, as France has been in favour of redistribution through CfDs while Germany has opposed the idea.

The Parliament will allow member states to use either CfDs or similar schemes with income ceilings and floors to meet the requirement, and it is emphasised that participation in such schemes must be voluntary. Furthermore, it is emphasised that the schemes must be in line with state aid rules and not disturb the internal market. Energy-intensive industry with a risk of carbon leakage is defined as one of the end-user groups that can be supported through the scheme, but Parliament believes that the industry should also be required to have a plan in place to achieve climate neutrality. Parliament calls for the Commission to publish guidelines on how legal CfD schemes can be designed and for ACER to monitor the possible effects of the scheme on the internal market.

Flexibility: EU countries will need emission-free flexibility solutions as the share of non-regulated power generation increases and fossil fuels are phased out. To ensure flexibility, it is proposed that each member state should assess and report on the need for flexibility in its national power system, and that based on these reports, a non-binding national target for consumption flexibility and energy storage should be set. If there is a risk that national flexibility targets will not be met, member states may establish their own support programmes.

Parliament also asks the Commission to develop a European strategy for flexibility and demand response in line with the 2030 climate targets and to use member states' reporting to ensure that the targets are met. The current rules for capacity mechanisms are not changed in the ongoing reform, but Parliament nevertheless asks the Commission to assess the need for changes and analyse the consequences and possibly follow up with a proposal for updated rules.

Next crisis: The Commission may declare a European electricity price crisis lasting up to one year if the following criteria are met: prices in the wholesale market have been at least 2.5 times higher than the average over the last five years and the situation is expected to last for at least 6 months, prices in the retail markets have increased by at least 70 per cent and the situation is expected to last for at least 6 months, and the economy is generally negatively affected by the high electricity prices. If an electricity price crisis is declared, member states can make targeted interventions in retail prices for SMEs and households, as long as a certain incentive for electricity savings is preserved. The electricity savings incentive can be safeguarded by ensuring that the subsidy only covers up to 70-80 per cent of the beneficiary's electricity consumption.

The Parliament will add that member states will be authorised to support energy-intensive industry in addition to SMEs and households in the event that an electricity price crisis is declared. Furthermore, some changes are proposed to the criteria for declaring a crisis, including that the price level in the wholesale market should be above EUR 180/MWh. The share of electricity consumption that can be covered is proposed to be increased - up to 100 per cent for vulnerable households.

Part 2 on protection against market manipulation

Part 2 of the reform consists of amendments to the REMIT regulation. REMIT aims to strengthen transparency and integrity in the European wholesale energy markets (electricity and gas) and prohibits insider trading, market manipulation and attempted market manipulation. Market participants must report all transactions at EU level for the energy markets to ACER, and ACER supervises the markets under REMIT. Since REMIT was first adopted in 2011, parts of the market design have evolved, new products have been developed and new players are participating in the energy markets. At the same time, confidence in the price formation in the energy markets was put to the test with the very high and volatile prices that followed Russia's throttling of gas exports to Europe from 2021. The Commission has therefore proposed several changes to REMIT. There are stricter requirements for market participants' reporting, and ACER is given extended responsibility for investigating possible market manipulation cases in cases where three or more member states may be affected. In general, the changes proposed in REMIT will have less direct impact on retail prices than those proposed in Part 1. Part 2 of the reform has also been less politically controversial. One topic that has caused some debate is ACER's expanded responsibility for investigating market manipulation cases, as the national regulatory authorities in the EU's largest member states in particular have been concerned that ACER will lack the resources to follow up on its mission. The Commission, for its part, has defended the proposal by pointing out that around 85 per cent of possible market manipulation cases affecting several member states have not been investigated, partly due to poor coordination between national regulatory authorities. Both the Council and the Parliament have adopted their positions on Part 2 of the electricity market reform. While the Parliament largely supports the Commission's proposal, the Council has proposed some limitations to ACER's proposed role in market manipulation cases.

Council position and German-French industrial power discussion: The Council adopted its position on Part 2 of the reform (on REMIT) already in June 2023. However, Part 1 on market design has been more controversial. In particular, member states have struggled to reach agreement on the rules for organising the proposed two-sided CfDs, with the Commission's proposal raising concerns that different CfD set-ups in different member states could lead to distortions of competition in the single market (see also chapter 17). France is among the countries that have put forward rules that would allow the state to use the two-sided CfDs to redistribute revenues from electricity producers to end users, including businesses, without this being considered state aid. France has long benefited from a special and temporary exemption from the state aid rules that has authorised the industrial power scheme ARENH, but this is scheduled to be phased out in 2025. France has therefore been motivated to create room for manoeuvre in the pan-European regulations for a new industrial power scheme. Germany and other northern European countries have been very sceptical about such use of CfDs, due to the above-mentioned concerns about competition conditions in Europe's internal market. At the same time, there has been a separate, national debate in Germany about the need for a separate industrial power scheme. In Germany, the concerns centre on the competitiveness of industry through the energy transition, and the coalition partners in the German government have discussed various schemes to ensure a predictable and competitive "transition price" for industry. While France has promoted a scheme that would redistribute revenues from power producers to consumers, Germany is discussing schemes that are based to a greater extent on state subsidies. If the German restructuring price for industry is to be realised, this will also require clarification at European level. Because Europe's two largest economies want to find new solutions to ensure competitive electricity prices for industry, one possible outcome could be that the pan-European regulations are changed to facilitate such schemes. If so, this could also affect the room for manoeuvre of other European countries, including Norway.

11.5.7 Long-term power market reform in the UK

In parallel with the ongoing process in the EU, the UK has initiated work on its own long-term power market reform. Unlike the EU, no legislative changes have been proposed yet, and both the further process as well as the outcome of the UK reform is currently unclear. The reform process began in 2022, with a political desire to decouple electricity and gas prices to curb end-user electricity bills. The process has since created a lot of political uncertainty and provoked strong reactions, especially from renewable energy investors who want the government to avoid fundamental changes to the existing market framework. The process and some of the measures that have been discussed in connection with the reform are outlined below.

The reform process began in July 2022 when the responsible ministries opened an initial consultation on changes to the organisation of the electricity market. In March 2023, a summary of the consultation was published, in which the government also clarified which measures are excluded and will not be taken further. It is expected that a second consultation will be opened in the autumn of 2023. The image below provides an overview of the measures that have been discussed in connection with the reform. Measures marked in red are excluded after the first consultation and will not be taken further. Measures marked in orange will not be taken forward on their own, but may still be considered in conjunction with other measures.

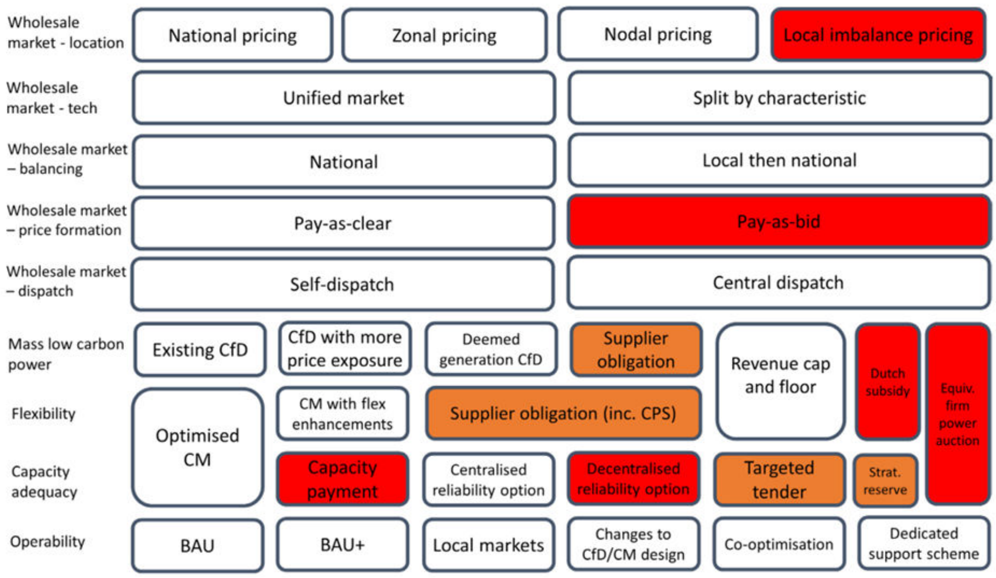


Figure 11- 5 Alternatives being considered in the UK (Department for Energy Security & Net Zero 2023)

Below is a more detailed description of some of the measures that have been debated in the UK. Since the UK is at a relatively early stage in the work on a power market reform, and it is unclear which measures may be relevant and how they may be designed, the Committee has not assessed possible effects on the Norwegian power system to any great extent:

Local price signals: The UK electricity market currently operates with a single bidding zone. In connection with the reform, several options have been discussed, including the creation of multiple bidding zones and node pricing. The UK's Transmission System Operator (TSO) is among those who have argued in favour of the importance of local price signals for efficient use of the grid. Renewable energy investors, for their part, have expressed concern that such changes could negatively impact investment signals for renewables, both because of the uncertainty the changes themselves create and because the alternatives are likely to result in lower price levels in areas with weaker grid connections.

Local markets at distribution level: The introduction of local markets, probably organised at the regional distribution network level, has also been discussed. These markets would, with the support of local distribution networks, ensure that local operational requirements are met. In each local market, power can potentially be purchased either from other local markets or from national markets. Participation in these local markets can be either mandatory or voluntary for consumers connected to the distribution grid. One of the objectives of such a scheme would be to get more precise price signals locally, but unlike changes in bidding zones, the scheme would not affect prices outside the UK.

Separate markets for variable and controllable power: One of the more radical proposals that has been discussed in connection with the reform is to split the wholesale market into two different markets for variable and dispatchable power. The details of this proposal are not clear, but the intention is to develop a separate market for variable production where prices will be relatively stable and reflect long-term production costs. Another market for adjustable power will operate as the wholesale market does today, with prices reflecting marginal costs. A possible benefit of such a measure would be the dampening and stabilisation of end users' electricity bills, if they can benefit from the lower and more stable prices in the market for variable power. The proposal is similar to the one put forward by Greece in connection with the EU reform process, but which was not followed up in the Commission's legislative proposal.

Low-carbon power: The UK currently uses two-way differential contracts to support investment in low carbon power. In connection with the reform, a number of alternative mechanisms have been discussed that could incentivise new investments, including

- Variants of the current scheme where producers are more exposed to the wholesale price, or where producers' income is linked to potential rather than actual production
- Introduction of a broader revenue cap and floor for producers with the aim of providing greater certainty around project revenues

The UK debate on "social tariffs": In January 2019, the UK government introduced an upper limit on the price retail companies can charge their customers in the retail market, in the form of a standardised variable tariff. This was done to prevent retailers from overcharging and was introduced based on a perception that the retail market was not able to deliver good enough deals to customers. The cap is adjusted periodically (currently every three months) by Ofgem, the energy regulator, and is based on the retail companies' costs in the wholesale market. Since this cap reflects the prices in the wholesale market, it does not provide any protection against high spot prices - only against market failure in the retail market. No similar measures have been introduced in Norway. The Commission assesses measures to address market failure in the retail market in chapter 16.

When the energy crisis hit, spot prices rose in the UK, as they did in the rest of Europe. This created political pressure for a social tariff that could also address high spot prices. During the energy crisis, a temporary, separate price cap (Energy Price Guarantee) was introduced, which could be below the spot price level and where the government paid the difference when the electricity suppliers' purchase price in the wholesale market was higher than the price cap. The level of the price cap has been adjusted several times, and after the summer of 2023 it has no longer had any effect since the cap has been higher than the Ofgem price mentioned above. The scheme is scheduled to be phased out in March 2024. The support programmes introduced in Norway during the energy crisis can be considered similar measures. The UK government has not officially advocated such a social tariff on a permanent basis, although this is a topic of discussion in the UK. In this debate, the term "tariffs" is used, but in reality it refers to a range of possible measures. For example, relevant measures could be a politically determined discount on the end-user's bill, graduated prices (where the end-user price rises with increased consumption), an absolute cap on energy bills, or possibly direct payments aimed at vulnerable consumers to be covered by the state budget. With this type of support measure, major disruptions to the marginal price signal in the wholesale market are avoided and support can be targeted at the consumer groups with the greatest need. The support programmes introduced in Norway during the energy crisis can be seen as similar measures, although these are intended to be temporary. The Commission assesses measures that can dampen retail prices in relation to the spot price in chapter 17.

12 Long-term perspective on price formation for electricity

By 2040, the power system in Europe will undergo a major transition to renewable energy sources. This transition requires more power exchange, flexibility solutions and storage solutions. There are a number of forecasts and scenarios for what the system may look like in the long term, but within the scenarios there is a wide range of outcomes for all these elements and thus uncertainty about what the system will actually be like.

In this chapter, we present some scenarios for how the energy system may look in the future. The aim of these is partly to have some scenarios against which to discuss various measures, and partly to point out some of the main features of price developments that the committee believes we need to prepare for.

12.1 The main factors that will affect power prices in Norway and neighbouring countries

Like most market prices, electricity prices are determined by supply and demand. As explained in chapter 6 and 7 there are many factors behind both supply and demand for electricity. Before presenting some scenarios for price and market developments, we will discuss the most important factors that affect prices in Norway and neighbouring countries.

Feed-in to the hydropower system

In long-term price analyses, we distinguish between random factors such as temperature and precipitation, and other factors such as changes in consumption and the level of ambition for climate policy and energy transition. Both Norway and Sweden have a large proportion of their production capacity as hydropower, and this will continue to be the case in the future. Power prices will therefore be affected by the inflow to the reservoirs. During periods of high inflow, there will be a large supply of energy and prices will be low. Low precipitation, both snow and rain, will push prices up. Price trends will also be affected by how much water is stored in the reservoirs and how each individual producer manages their reservoirs.

Both meteorological observations and climate research indicate that expected inflow and the variation in inflow, both from one year to the next and within each year, will increase somewhat in the future.

The Norwegian and Nordic power balance

The relationship between supply and demand in each bidding zone and the possibility of power exchange between bidding zones is crucial for prices. In bidding zones where demand grows faster than supply, prices will rise compared with bidding zones where supply and demand grow in step. Statnett's long-term market analysis illustrates the impact of power balance on the price level in various Norwegian and Nordic bidding zones, see Figure 12-.

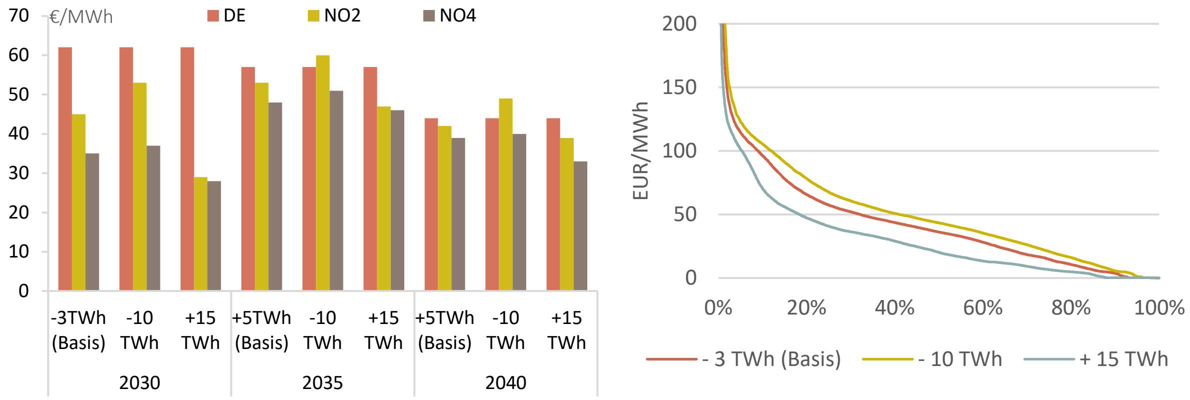


Figure 12- Illustrations from Statnett show the relationship between power balance and price level and price variation (Source : (Statnett 2023)

The Energy Commission has analysed the relationship between different levels of the power balance and inflow, temperature and wind (different weather years) for 2030. The greater the power deficit, the higher the price level will generally be.

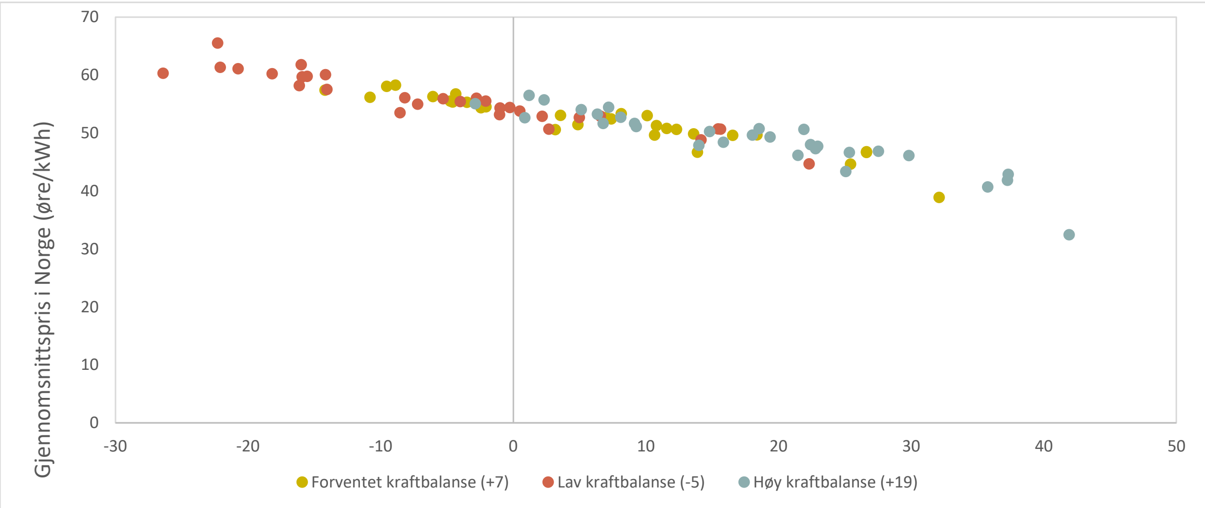


Figure 12- 2 Correlation between power balance, weather year and power price (Source: Energy Commission)

Energy mix

The European energy mix is changing, Figure 12-. For power generation, from mainly regulated production based on fossil fuels, to unregulated technologies based on solar and wind power on land or at sea. The inclusion of nuclear power and possibly hydrogen as a flexibility solution will also affect the characteristics of the future energy system and thus the price mechanisms in the power market.

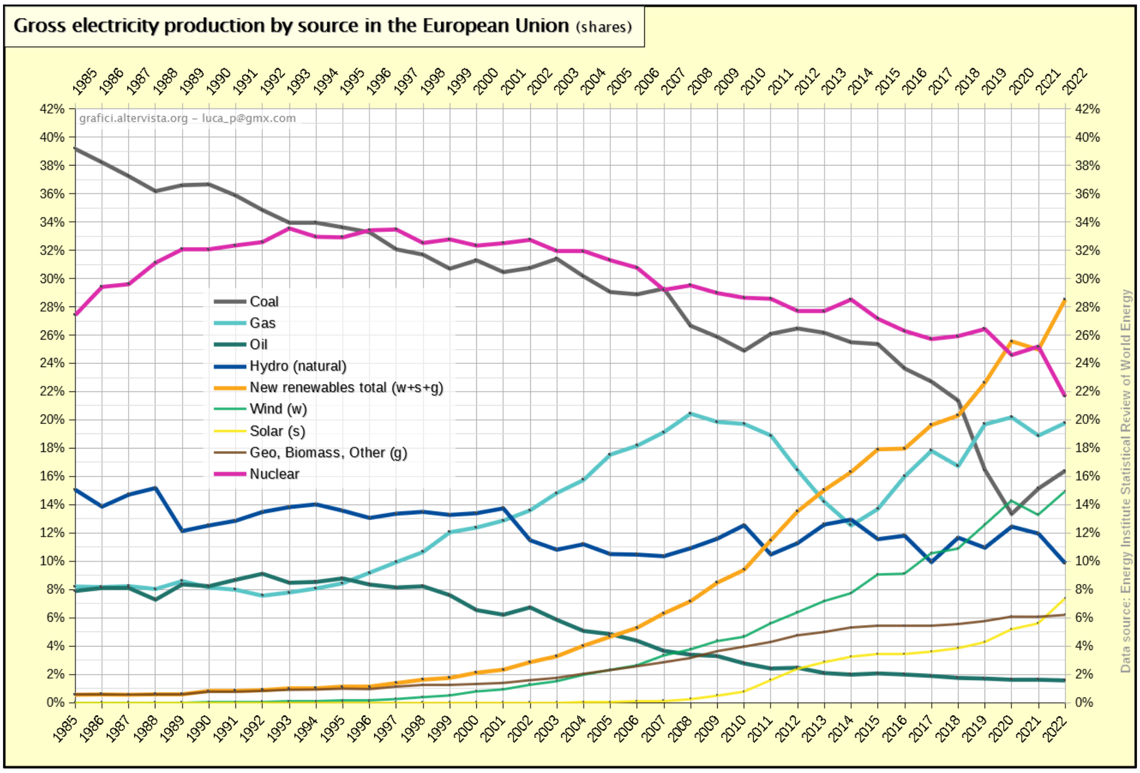


Figure 12- European energy mix (Source: https://grafici.altervista.org/)

The Norwegian energy system is currently in a unique position - renewable and mainly based on regulated hydropower. In the future, there will be a greater proportion of unregulated production from solar and wind power on land and at sea in Norway as well.

What the prices in the market will be will depend primarily on the future energy mix in Europe. If the European energy mix will consist to a small extent of regulated production, Europe will need the flexibility of Norwegian hydropower. This could provide opportunities for good utilisation and value creation for power production in Norway.

Flexibility on the demand side

As fossil-fuelled power plants are phased out, the ability of the demand side to handle fluctuating energy supply will become increasingly important. Low flexibility on the demand side means that prices will vary more to ensure a balance between supply and demand than if flexibility is high. A key source of flexibility used in many scenario analyses and considered relevant in Europe is the production of hydrogen based on electrolysis of water (green hydrogen). Whether this technology will be realised as a source of flexibility remains to be seen. Several of the hydrogen projects being considered in both Norway and Europe assume steady consumption of electricity. If so, these will not necessarily contribute to the desired flexibility on the demand side.

Prices of fossil fuels and CO quotas$_2$

Price formation in Europe and Norway is strongly influenced by price developments for fossil fuels and for quotas and other measures to limit CO_2 emissions from power generation. In the past, the price of coal has had the strongest impact on price formation, but in recent years gas prices have become increasingly important. The competition between gas and coal is affected by the producers' costs of CO_2 emissions. Per unit of energy, emissions of greenhouse gases are about twice as high with coal-fired power compared with gas-fired power.

The CO_2 price is influenced by European authorities by reducing (or increasing) the number of allowances available in the market.

Gas prices are affected partly by the fact that both the supply of and demand for Russian gas has fallen sharply, partly by the global market for liquefied natural gas (LNG) and not least by Europe's capacity to receive LNG.

The impact on power prices from CO_2 prices and fossil fuel prices will be reduced over time. Climate policy is organised in such a way that renewable energy and possibly nuclear power will displace fossil fuels. The speed of this transition is one of the uncertainty factors for the market going forward.

Transmission capacity
While fossil fuel power plants were mainly built where there was a need for electricity, renewable energy, especially wind power plants, are built where there is a good resource base. Since many countries in Europe are investing in the same technologies (wind power and solar energy), the supply-side correlation between neighbouring countries is increasing. For many countries, the opportunities to import from the nearest neighbouring country in the event of a local power shortage are relatively smaller than before, because the probability that both have the same wind and solar conditions is high.

Overall, this means that the power systems in Europe are generally becoming more dependent on capacity in the electricity grid - both within individual countries and between countries. The pace of grid development will therefore be a key driver for price developments and the speed of the energy transition.

However, an important point is that for Norway, increasing solar and wind power in our neighbouring countries will, in isolation, contribute to a higher value of both Norwegian hydropower resources and the connections between Norway and other countries.

12.2 Scenarios for 2040

The committee has looked at the long-term development of the power system. The energy crisis has shown that it is impossible to take into account all possible situations that may arise. We have therefore chosen to look at different scenarios for the future energy system in neighbouring countries to understand the possible consequences of different developments for the Norwegian power system.

All scenarios assume that large amounts of renewable, non-regulated power will be developed in the countries around us. The majority of this is assumed to come from solar energy and wind power on land and at sea. One challenge in a system with a lot of new renewable and unregulated power is to ensure flexibility to handle short periods when the sun is not shining and the wind is not blowing. Another important challenge is to ensure enough flexibility to get enough power when this happens over a longer period of time ("dark slack"). Whether and how this is resolved can have a major impact on pricing. We have therefore chosen flexibility in neighbouring countries as an important dimension in the scenarios.

In the Norwegian power system, the power balance is important for price formation, not least how competitive Norway's prices are. In general, a surplus in the power balance results in net exports. Net exports mean that prices abroad are higher than at home. The power balance is also important for Norwegian security of supply. We have therefore chosen the power balance in Norway as another important dimension in the scenarios.

The four scenarios illustrate different situations that may arise on the way to a zero-emission society.

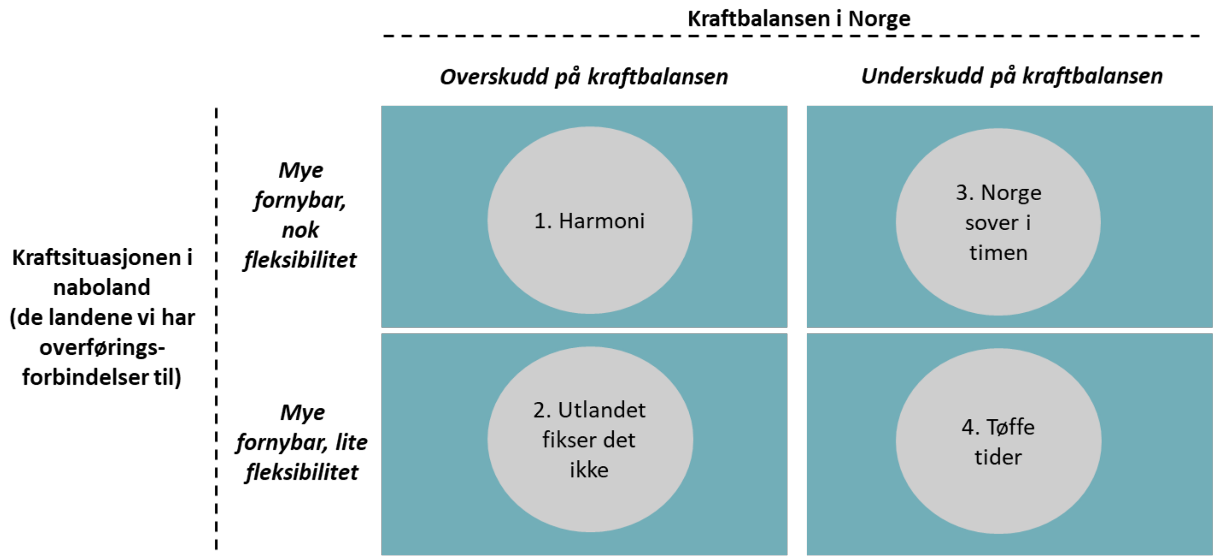


Figure 12- 4 The four scenarios analysed in this work.

We have used a data set from NVE for the years 2021 and 2040 as a starting point for the analyses. The dataset is NVE's assessment of what may happen to the development of the power system up to 2040. Using this as a starting point, Sintef[47] has performed a number of partial analyses that we have used to illustrate various dimensions of the development.

The assessments we have made in relation to the four scenarios are summarised in the table below, with a more detailed description in the following sections. We compare each of the scenarios with a situation similar to the one we had before the pandemic and the energy crisis hit. This situation was characterised by relatively low, stable and predictable prices in Norway, although fluctuations due to wet and dry years could be significant, see Part I.

Scenario	Norwegian electriciy balance	Flexibility in neighbour countries	Price level before the energy crisis	Price volatility	Predictability	Security of supply
1	Surplus	High	Somewhat higher	Somewhat larger	Somewhat reduced	Unchanged
2	Surplus	Low	Somewhat higher	Larger	Somewhat reduced	Somewhat reduced
3	Deficit	High	Higher	Somewhat larger	Somewhat reduced	Somewhat reduced
4	Deficit	Low	Higher	Larger	Reduced	Reduced

Figure 12- 5 Summary of the results from the analyses of the four scenarios

[47] The dataset includes 30 weather scenarios 1981-2010, detailed modelling of the Nordic region: Norway, Sweden, Finland, Denmark, exogenous price series: UK, Netherlands, Germany, Poland, Baltics (from TheMA model), adjustment of rationing and disconnection price as agreed with NVE, development of production and consumption based on existing plans and best estimates, somewhat conservative assumptions in development of demand compared to Statnett's long-term market analysis (LMA).

12.2.1 Scenario 1: Harmony - Surplus in the Norwegian power balance and a lot of renewable energy and flexibility in countries outside the Nordic region

What changes in particular from the situation before the energy crisis is a sharp increase in unregulated production (wind and solar), and a sharp increase in demand in Norway. Significant demand flexibility from hydrogen/ammonia production is also assumed. There is a positive power balance, or power surplus, but somewhat less than today.

The sharp increase in both production and demand in the future is expected by the vast majority of those who develop long-term analyses for the power market, including Statnett, NVE and many analysis companies. The main reason for the development in consumption is expectations of phasing out fossil energy sources through increased electrification of transport, the petroleum industry and existing industry. In addition, increased consumption is expected from the establishment of new industry. Most analyses assume that consumption will be covered by increased investment in solar energy, wind power and hydropower. The exact size of the expected increase varies between the analyses, but the direction of development is similar.

The sharp increase in solar and wind power has two consequences for prices. Firstly, the increased element of unregulated production means that price variations from hour to hour and between days will increase compared with the current situation. In Norway, this effect is mitigated by regulated hydropower production, but the variations will be greater than what we are used to historically.

Secondly, the increased share of wind and sun means that the supply of energy is more stable between years. How much it rains in one year compared to another year varies much more than the difference in wind and sunshine between two years. This means that around 30 TWh more solar and wind come in each year without much variation from year to year in this scenario. This is a reasonably constant additional power generation. This is illustrated in the figure below.

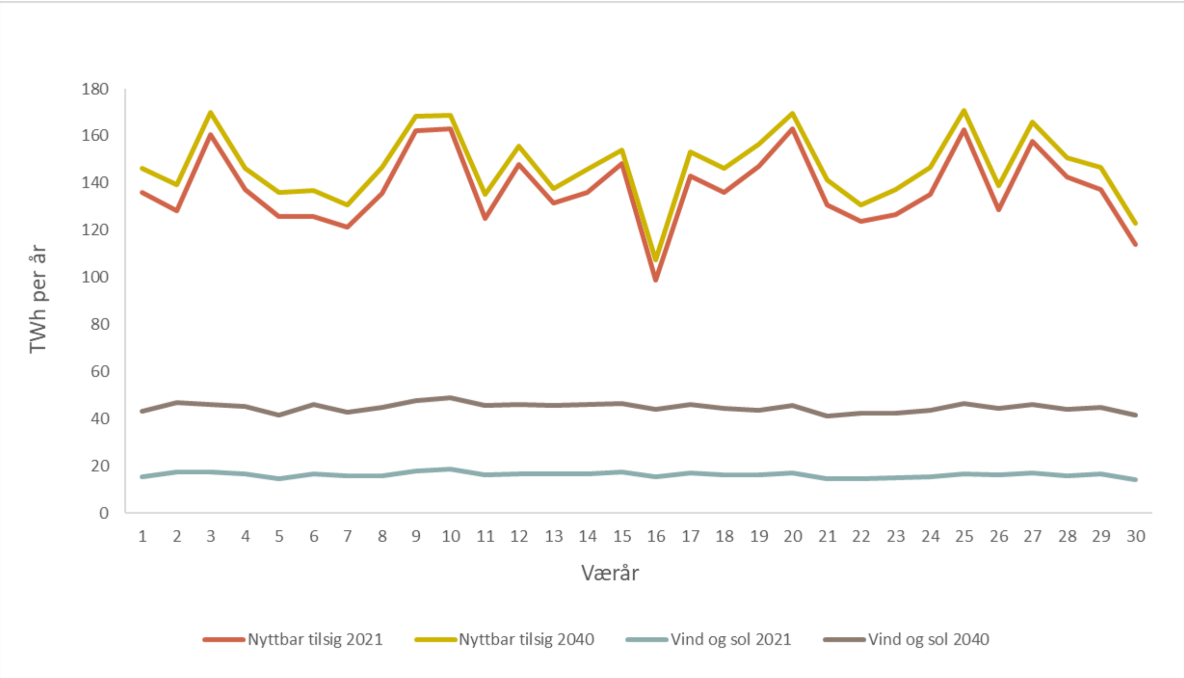


Figure 12- 6 Access to hydropower and production for wind and solar power for different weather years

The figure shows the variation in the inflow to hydropower measured in TWh and the production of wind and solar power in 30 different weather years in the period 1981 to 2010.

The demand flexibility that comes from hydrogen/ammonia production means that consumption is reduced if prices are high. When demand is reduced, prices are also reduced to the benefit of other consumers compared to what they would otherwise be.

Another important factor for price formation in Norway is the price level and price structure in neighbouring countries. In this scenario, it is assumed that neighbouring countries develop sufficient flexibility to even out the fluctuations from increased renewable energy production. Nevertheless, the large share of renewable energy will entail greater price variations than today.

The figure below shows a duration curve for German prices in 2021 (observed) and 2040 (assumed in the data set). The duration curves take all the prices that appear during a year and place them in order from lowest to highest price over the year. The red curve shows the prices in 2021 and the yellow curve shows the prices in 2040. The red curve shows a gentler slope than the yellow one. This means that prices are more stable in 2021 than in 2040. If we follow the yellow curve from left to right in the figure, we see that there are several weeks with almost zero prices before the curve rises sharply and prices are higher than in 2021. To the far right of the figure, we see that prices are much higher than the red curve for 2021.

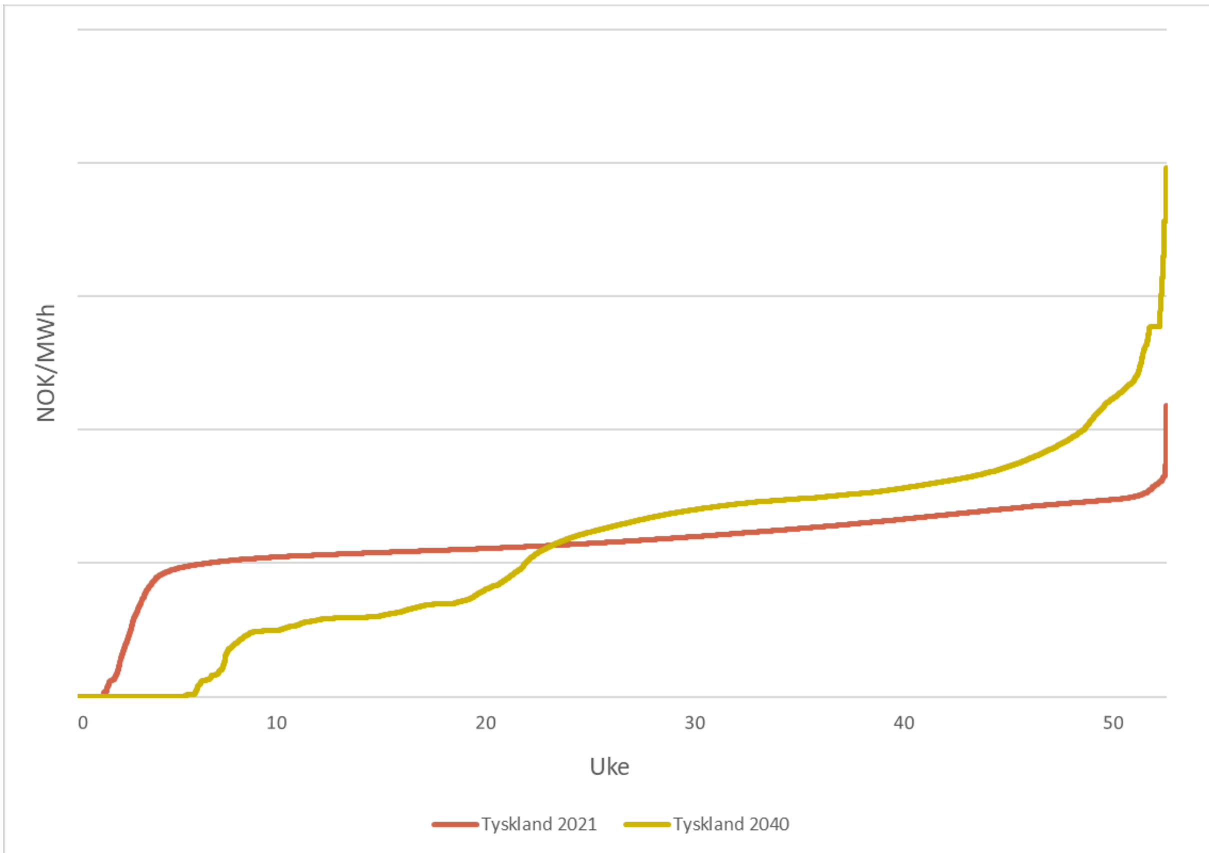


Figure 12- 7 Duration curves for German prices, observed in 2021 and assumed in 2040.

This shows that prices are expected to vary more in a power system with a greater proportion of renewable and non-regulated energy than we have today.

So what can we say about the price effects for Norway in this scenario compared to the situation before the energy crisis?

We would like to remind you that in this scenario we assume a power surplus in Norway and a lot of flexibility in neighbouring countries. We estimate the price effects to be as follows:

- *Price level. The* analysis that has been carried out points towards a somewhat higher price level in the long term than what has been observed historically in Norway before the energy crisis.
- *Price stability:* The short-term price variations (hour to hour, day to day) increase as a result of more solar and wind power. However, prices are more stable between years as a result of more energy that the same solar and wind power adds to the Norwegian system. Overall, prices are considered to be somewhat less stable.
- *Predictability:* Despite increased demand flexibility, which means that the chance of high prices is reduced, the increased price variation in neighbouring countries will contribute to somewhat less predictable prices.
- *Competitive prices*. We have a power surplus in this scenario, which means that in years with normal inflow, we will have net exports to our neighbouring countries. As previously explained in chapter 7, we export when prices are higher abroad than at home. When we have more hours of exports than imports, this indicates that the price level in Norway is lower than in our neighbouring countries. This means that we have competitive prices with Europe. The higher price level may weaken our competitiveness with countries outside Europe if these countries do not receive the same price increase for electricity as in Europe as a result of the energy transition.

A situation with greater short-term price variations, as in this scenario, means that there will be stronger incentives for both power producers and consumers to invest in short-term flexibility. For power producers, this could mean investing in greater power capacity, while for consumers it could mean investing in distributed energy storage and increased equipment to even out consumption over the course of the day.

The higher price level strengthens the incentives to invest in more power generation. Prices are also relatively stable and predictable, which makes it easier for investors to assess future prospects when making their judgements.

It is more difficult to assess whether it will trigger more power production. It depends on the price level and, not least, the cost development for new production. If the cost of investing in new power generation is lower than the expected price level, more power generation will be invested in if there are no other barriers to establishment.

Security of supply and good resource utilisation
There is a power surplus and plenty of flexibility both in the Norwegian power system and in neighbouring countries in this scenario. The Norwegian power system should be equipped to cope with an extended period with little wind and little sun in our neighbouring countries, even in a dry year. Prices will rise in such a situation, but sufficient flexibility in our neighbouring countries should ensure that there are no supply-related challenges. This means that security of supply is well taken care of.

In wet years, the power surplus in Norway will be large in this scenario. The exchange capacity with other countries will mean that we can sell the power, but at lower prices.

As we have many exchange connections to different countries with different weather conditions, the risk of challenges related to security of supply and less efficient resource utilisation is reduced compared to a situation with exchange capacity to fewer countries.

12.2.2 Scenario 2: Foreign countries can't handle it - Surplus on the Norwegian power balance and a lot of renewable energy and little flexibility in countries outside the Nordic region

In this scenario, it is the composition of power generation in countries outside the Nordic region that changes. Here we envisage a development where the expansion of flexibility on the supply and demand side does not keep pace with the development of renewable and unregulated energy such as solar and wind. There are many reasons why this could happen. It is unlikely to be a situation that will persist over time, but it is a situation that can take time to correct if it does happen.

Too little flexibility means that price variation will be much greater in neighbouring countries. This can be illustrated by adding another duration curve to the figure we showed earlier. The new curve has even more hours with very low prices and a steeper slope. When there is less flexibility in the power system, prices become even more sensitive to weather and wind, which affects power generation from solar and wind power.

What are the price effects in this scenario compared to the situation before the energy crisis?
In this scenario, the price effects are assessed to be:

- *Price level. The* lack of flexibility leads to more hours with high prices abroad, which also affects Norwegian prices, resulting in a higher average price level over the year compared with scenario 1: Harmony, and consequently also compared to the situation before the energy crisis.
- *Price stability:* A lack of flexibility in our neighbouring countries means that price variations abroad are greater. Price variations in neighbouring countries also mean greater variations in Norwegian prices. The flexibility of hydropower will help to reduce price variations in Norway compared to other countries, but compared to what we have historically been used to, the price variations will probably be far greater.
- *Predictability:* The large price variations result in less predictability for prices.
- *Competitive prices*. The power surplus means that Norwegian prices on average over the year are still lower than prices in European countries outside the Nordic region. The reason for this is that although the higher value of any power exports pushes up Norwegian power prices, the poor flexibility in Europe also means that at times they have significantly more production than they have consumption. This opens the door for more imports compared with more exports. As always, it will be the Norwegian power balance that controls the net exchange, and differences in access to resources (wind, solar, water, etc.) that control competitiveness with neighbouring countries in the long term. As in the previous scenario, competitiveness could be weakened against countries outside Europe.

Greater price variations provide stronger incentives for both power producers and consumers to invest in flexibility. For power producers, this can mean greater power capacity, while for consumers it can mean investments in distributed energy storage and increased equipment to even out consumption over time.

The higher price level strengthens incentives to also invest in new production, but is somewhat weakened by the fact that the market outlook in this scenario is more unpredictable.

Somewhat less good security of supply and resource utilisation
The power surplus in Norway helps to ensure security of supply. The power surplus is also important for managing longer periods with little wind and sun in our neighbouring countries. In such a situation, prices will rise as Norwegian hydropower's flexible resources will have a high value abroad. This situation will be further exacerbated if it coincides with a dry year in Norway.

There is a greater risk of wasting resources in this scenario. In a wet year, the production of renewable energy in neighbouring countries may be very high due to the weather, and the countries may not be able to accept imports from Norway. This increases the risk of flood losses. However, our many exchange connections to various countries reduce the risk.

12.2.3 Scenario 3 - Norway sleeps through the hour: Deficit in the Norwegian power balance and a power situation in neighbouring countries with a lot of renewable energy and enough flexibility

Here, the big difference from the first two scenarios is that we have a power deficit in Norway. In this scenario, we assume that our neighbouring countries have developed enough flexibility to handle price variations. They avoid serious energy shortages and do not have major problems with power production exceeding consumption and leading to periods of negative prices.

What are the price effects in this scenario compared to the situation before the energy crisis?
In this scenario, the price effects compared to the situation before the energy crisis are considered to be:

- *Price level.* The power deficit and thus increased imports of power from neighbouring countries are contributing to a higher price level in Norway than before the energy crisis.
- *Price stability:* Price fluctuations in countries outside the Nordic region will be more levelled out by the countries' own flexibility. European prices will probably still be more volatile than they have been historically because the power system will become more weather-dependent. However, the degree of volatility will depend on which sources of flexibility become dominant in Europe. The power deficit also means less price stability in Norway, as we will be more affected by European prices as a result of increased import requirements. With a power deficit, we have to import from Europe more often than with a power surplus. Some of these increased imports will probably occur during periods when we would otherwise have exported if we had a power surplus. Some of the imports will therefore be at prices that are higher than current import prices. Since there are limits to how low power prices can be over time, but almost no limits to how high they can be (skewed probability distribution), this implies higher price volatility in Norway as well.
- *Predictability:* The power deficit results in less predictable prices.
- *Competitive prices*. A power deficit will result in Norway importing more power. As the prices around us are more stable and do not allow us to import large amounts of power at zero prices, this means that Norwegian prices are no longer as competitive compared with Europe.

Higher prices as a result of power shortages strengthen the incentives to invest more in power generation and to increase investment in energy efficiency. Prices will probably vary more than they do today, which means that the regulating capacity of hydropower will be in demand. This strengthens the incentives to invest in more power.

Somewhat weaker security of supply, but good resource utilisation
The power deficit contributes to weakened security of supply. At the same time, the scenario assumes that a great deal of flexibility has been developed in the countries around us. This means that we can rely on being able to import the power we need from neighbouring countries. As there is large capacity in the transmission links with several other countries, this is unlikely to cause major supply problems even in dry years.

The power deficit also means that there is less risk of water spillage in wet years, which means that resources are utilised.

12.2.4 Scenario 4 - Tough times: Deficit in the Norwegian power balance and a power situation in neighbouring countries with a lot of renewable energy and little flexibility

In this scenario, we have both a power deficit in Norway and little flexibility in the power systems around us. This makes us vulnerable to situations in both the Norwegian power system and the power systems in neighbouring countries.

What are the price effects in this scenario compared to the situation before the energy crisis?
In this scenario, the price effects compared to the situation before the energy crisis are considered to be:

- *Price level.* The power deficit in Norway contributes to higher prices here. The power surplus around us allows for imports at low prices in Europe, which can drive Norwegian prices down for periods. However, on average over time, the price level abroad in this scenario will be higher than the situation before the energy crisis. 'Enough' energy in combination with little flexibility means that foreign countries will have long periods of low prices and long periods of (very) high prices in Europe.
- *Price stability:* Large price fluctuations in neighbouring countries also lead to large price fluctuations here at home.
- *Predictability:* We are more affected by the price level in Europe in a situation with a power deficit at home. The price level abroad in this scenario is highly weather-dependent and will have large variations. This also means greater unpredictability.
- *Competitive prices*. A power deficit will result in Norway importing more power. This tends to result in higher prices in Norway compared with neighbouring countries. At the same time, there may be time-limited periods when we import a lot of power at low prices from neighbouring countries and export at high prices, which overall may result in lower average prices than our competitors.

A crucial difference, however, is that Norway can have relatively good flexibility in the power system even with a deficit in the power balance (due to hydropower). In other countries, on the other hand, the premise of the scenario is that they do not have enough flexibility to avoid serious shortages and significant surpluses in other periods. They will have to deal with this in one way or another. Even if this is not necessarily reflected in average market prices, there will be costs that users of the power systems abroad will have to cover. As an illustration of this, we can think of Germany's sharp growth in the cost of managing imbalances. What is certain is that our global competitiveness depends even more than in the other scenarios on the pace and scope of our neighbouring countries' development of renewable energy and necessary flexibility.

High value of Norwegian flexibility, but weakened security of supply
Norwegian reservoir power is of great value as a result of large price variations and a generally higher price level. For other Norwegian producers (wind power, solar energy, river power) that have unregulated production, it is more uncertain and a question of what prices they achieve. If unregulated production in Norway coincides with high production abroad, they will generally achieve far lower prices than in reservoir power. Higher prices as a result of the power deficit and the large price variations strengthen the incentives to invest more in regulated power generation and to increase investments in energy efficiency and demand flexibility.

Power deficits and low flexibility in countries outside the Nordic region challenge security of supply. Neighbouring countries do not have enough flexibility in their systems to ensure that we can import enough power if we really need it. A dry year that coincides with a long period of cloudy weather and no wind can pose challenges for security of supply. If security of supply is challenged, the potential costs to society can be very high.

12.2.5 What do the scenarios tell us?

As all the scenarios show, we can expect higher and more volatile prices in the future. Having a power surplus is an advantage for Norwegian competitiveness. This means we can be more certain that we have lower prices at home than abroad. But it is not the case that if we tilt towards a small deficit, prices in Norway will automatically be higher than abroad. The price structure abroad, which depends on the power mix and power balance, is very important.

Whether we should have a power surplus in Norway is a political question. The most important instruments are to ensure acceptance and licence processes so that developments on the supply side can keep pace with developments on the demand side. Whether it is necessary to use economic instruments, such as the electricity certificate scheme or differential contracts that are planned for wind power in the North Sea, and which appear to be the solution the EU is prioritising in the future, is an open question.

An expansion of power as outlined in these scenarios will contribute to the electrification of society and thereby reduce greenhouse gas emissions. This transition is a result of the climate targets set at home and in Europe. At the same time, the development of power involves intervention in nature. There is therefore a need for important political trade-offs along the growth-conservation dimension of the conflict line.

Access to flexibility will also be a key challenge going forward. First and foremost in Europe, which is facing an even greater energy transition than we are, but also in Norway it will be important to ensure sufficient access to supply and demand flexibility.

There are also significant uncertainties related to how the actual price formation will take place in the future that are not covered in the scenarios. One of the uncertainties is whether market prices will trigger sufficient investment to achieve the climate targets, or whether subsidy programmes will be necessary. This may have an impact on the prices encountered on the other side of the interconnectors.

In all the scenarios discussed, the energy system must be remodelled. To replace coal and gas-fired power plants with high emissions, large amounts of renewable energy will be introduced into the power system, while at the same time new flexibility will be built in that will be emission-free.

Most countries in Europe have historically utilised a number of measures to trigger investments in renewable energy and flexible power. To a small extent, these investments have been triggered by market prices alone. With the large amounts of renewable energy to be developed in Europe, it is difficult to imagine that this will continue to happen without measures.

What could this mean for the market prices that Norway faces on the other side of the interconnectors ? As mentioned in chapter 11 using contracts for difference to trigger investments in renewable energy. Difference contracts mean that the developer receives a fixed price for what is produced from, for example, an offshore wind farm. The power is sold in the wholesale market. If the market price is higher than the fixed price, the difference is paid back to the government. If the opposite is the case, the government pays the developer the difference.

A large-scale expansion means that a lot more power enters the market. This in itself means that prices will fall. As we know, solar and wind energy are weather-dependent. This also means that when the wind blows in one wind farm, it also blows in the neighbouring wind farm, so they produce at the same time. The same applies to solar energy: if the sun is shining on your solar farm, it's also shining on your neighbour's. This creates another effect in the market, what we call cannibalisation. This means that when there is a lot of wind or sunshine, a lot of power enters the market at the same time and prices plummet. This means that wind power and solar energy are exposed to prices that are often lower than the average price.

The figure below illustrates this for Germany. The vertical axis shows what proportion of the average price in the market is achieved by offshore wind, onshore wind and solar energy historically and in an expected development. In this example, quite a lot of demand flexibility in the form of hydrogen production has also been included, which reduces the impact.

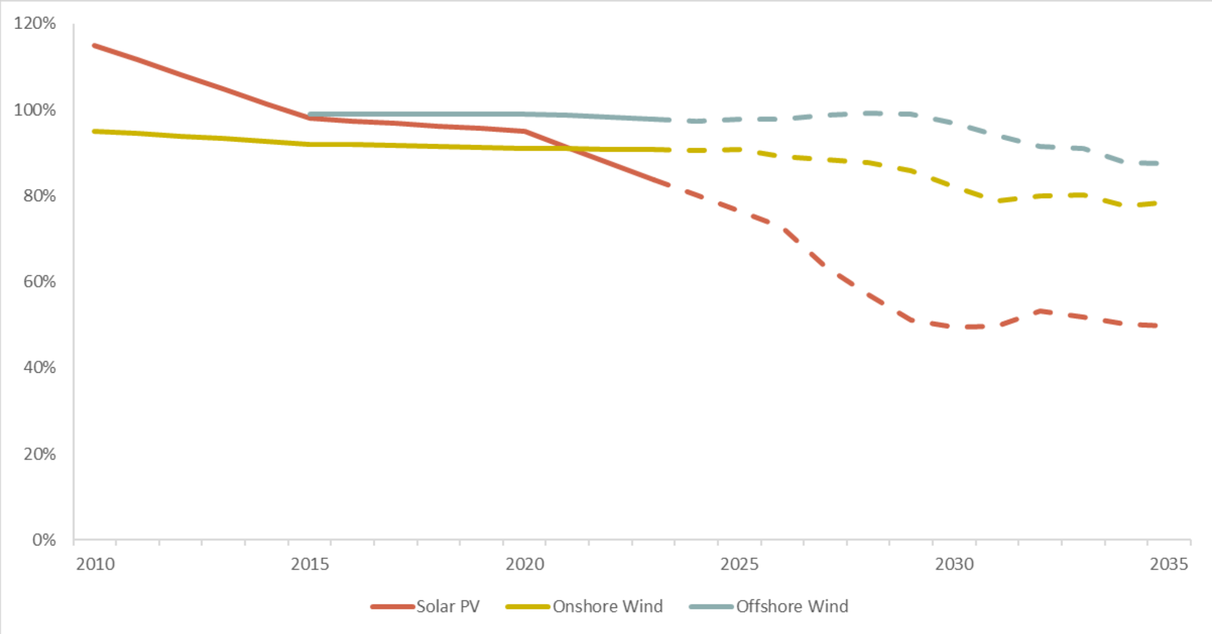


Figure 12- 8 Historical prices and expected future prices for solar and wind in Germany (Source: THEMA Consulting Group)

Firstly, this means that prices are under strong pressure for periods of time, and that these periods increase as the non-regulatable share of renewables increases.

The next question is, if the price in the market is not sufficient to trigger investments in renewables, will there be a sufficient number of hours with high prices to trigger investments in flexibility in the form of gas-fired power plants that can utilise emission-free hydrogen, for example?

An analysis carried out by the Department for Business, Energy and Industrial Strategy (the then UK Department of Energy) showed that there would not be enough high price hours to provide a reasonable return on investment in flexible power generation. In other words, market prices will not necessarily be sufficient to trigger investments here either. In that case, it will also be necessary to support the development of flexible power generation.

The sum total of such a development could be that we encounter low spot prices at the other end of the cables, which will have an impact on Norwegian water values and prices. This would then lead to lower prices in Norway, resulting in lower profits for producers and lower costs for consumers.

Norwegian hydropower producers with reservoirs will probably be paid for their ability to be regulated, as there will probably still be major price variations in the European markets. This may mean that power investments will be profitable. Lower average prices as a result of the extensive use of subsidy programmes for power generation in Europe may also make it more difficult to trigger investments that would "normally" be triggered by the market price in Norway. It may then also be necessary for Norway to subsidise the development of new production.

So what about the competitiveness of Norwegian industry? Here we see a development in the European market where the price of electricity accounts for an increasingly smaller proportion of the total costs paid by consumers. As we remember from chapter 8, consumers pay both grid tariffs and various taxes and fees in addition to the electricity price. If the development of a large amount of new renewable energy is supported by the authorities and consumers are charged higher taxes, the falling electricity price will represent an increasingly smaller share of the total cost.

Ultimately, we could end up with a situation where the European electricity price is lower than the Norwegian price, even though the total costs per kWh are far higher than in Norway. The competitiveness of Norwegian industry will then depend on how much of the grid tariffs and other taxes and charges are imposed on competitors. If competitors are not charged their "fair" share of taxes and fees (for example, if other consumers pick up the majority of the bill), Norwegian industry's competitiveness is weakened.

12.2.6 What happens if Germany is split into two or more bidding zones?

What happens in our neighbouring countries has an impact on price formation in Norway. It is not only changes in the physical power system that can have consequences for Norwegian prices.

One example of such a change is if Germany, which currently has only one bidding zone, decides to introduce more bidding zones. Germany currently has major internal bottlenecks in its grid, which are currently handled through countertrading. In 2022, German system operators spent EUR 4 billion on countertrading (BDEW 2023). A more efficient way of dealing with this would be to divide the country into several bidding zones, as we have in Norway.

This would have major consequences for German prices. A recent analysis has simulated what the price effects will be if Germany is divided into two bidding zones, one in the north and one in the south (THEMA 2023). The effects are illustrated in the figure below.

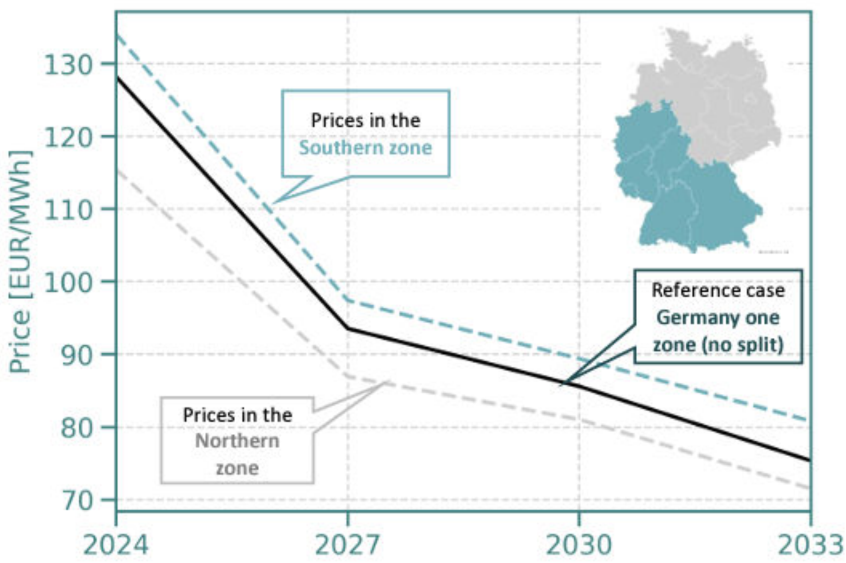


Figure 12- 9 Effect on prices if Germany goes from one to two bidding zones (THEMA 2023)

The reference case shows expectations for German prices without additional bidding zones. The other lines show the price effects in southern and northern Germany in the event of a split into two bidding zones.

The price in northern Germany will be the lowest because this is where a lot of new renewable energy has been developed that is currently locked in. A lower price in Germany will also contribute to lower prices in Norway, directly as a result of the transmission links to northern Germany and more indirectly through the price effects in other countries to which we have a connection.

The scenarios and these additional examples of what can happen around us, which have an impact on the price effects in Norway, show that the uncertainty about the future development of the electricity market is very high. The fact that the range of outcomes is large and unclear means that it is difficult to understand the full consequences of the measures that are implemented.

This emphasises the importance of testing the robustness of all measures against a wide range of outcomes before they are implemented. This applies particularly to measures that are difficult to change and adjust afterwards.

12.3 The importance of transmission capacity

There has been much discussion about the importance of transmission capacity in recent years. In order to understand the direct consequences of different levels of exchange capacity, the committee has asked SINTEF to carry out analyses to look at price effects, security of supply and utilisation of our renewable resources in line with the committee's mandate.

The quantitative assessments are based on the first scenario (Harmony) for 2021 and 2040. The analyses are not designed to study a realistic development of the power system with and without different connections during this period. On the contrary, the analyses are specified to illustrate price formation in a power system as in 2021 and a power system as in 2040 if the relevant interconnectors 'suddenly' disappeared. The purpose of this design is to purify the direct price effects, without modelling the possible consequences. Such hypothetical assessments have been made of price effects with islanding and by cutting the direct current interconnectors (HVDC) compared with retaining the exchange capacity. This is not intended to reflect realistic choices in the short term:

- In the example of island operation, we point out the consequences of cutting all power trading around us. In this case, prices are set without any direct influence from the European power market. This means that the weather, and in particular the inflow to hydropower production, is all the more important and must be managed without the possibility of exchange to other areas. When there is no exchange with other countries, the price of power in Norway is largely determined by how consumption changes with the price and the probability of underreaction, and by the probability of flooding, in addition to the price of production other than hydropower. A change in the average power balance in Norway will therefore have a major impact on the price level. This means that the price effects are very sensitive to changes in reservoir utilisation.
- In the example of direct current interconnectors, we point out the consequences of cutting all power trading via the subsea cables to Denmark, Germany, the Netherlands and the UK. Connections to Sweden and Finland are maintained.

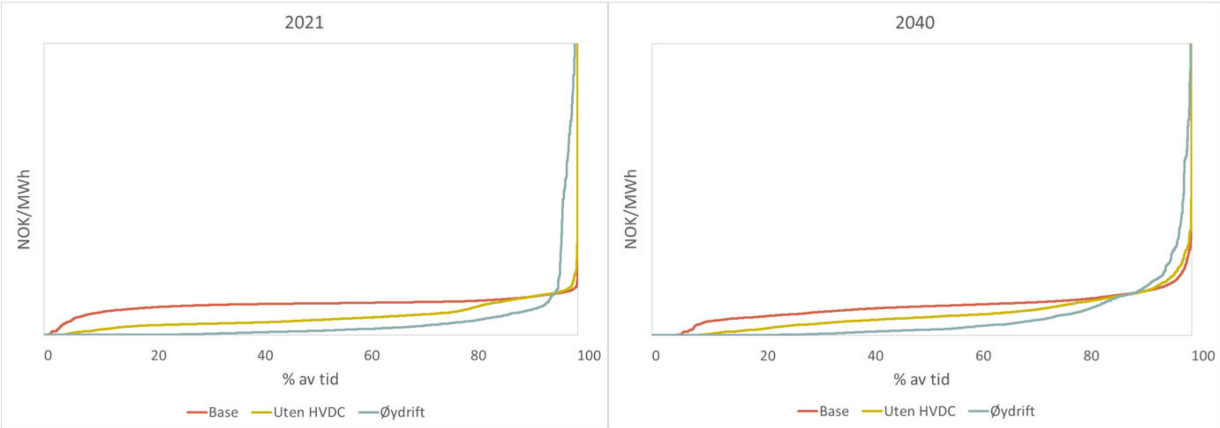
In addition, the consequences of changes in the power balance and the impact of a changed European power price level on power prices in Eastern Norway in 2021 and 2040 have been assessed for each of the examples.

It is important to emphasise that the projections for production and consumption on which the simulations are based (before assuming island operation or cutting HVDC) are made on the assumption that there is full exchange between Norway and our neighbouring countries. This means that the development of production and consumption from 2021 to 2040 takes place with this as an important framework condition. When we then look at the consequences of islanding and of cutting the HVDC cables, we see the effects of making the change in the year in question, i.e. in 2021 and in

2040. This emphasises that the curves below reflect a hypothetical situation to illustrate what interconnectors do to price formation in a short-term perspective.

If we imagine that we decide today to cut all HVDC cables in 2040, the assumptions for investors on the production and consumption side would change compared with what is assumed in the projection. The power balance and the composition of the production and consumption side would then look different in 2040 (due to the decision to cut). Comparing results for 2040 with and without the DC links is therefore not entirely realistic, because a decision like this will affect how the power system develops. The difference is what we refer to as dynamic effects, or second-order effects, which are discussed more generally in chapter 7.2. However, what we can read from an analysis like this is first and foremost the difference that the interconnectors create and that might have been resolved in some way without the interconnectors. We also illustrate the first-order effect (the price effect in isolation).

In the following, we show duration curves for power prices in Eastern Norway for the three examples Base, Øydrift and HVDC cables.



In the duration curve, we have placed all the prices achieved hour by hour throughout the year in

Figure 12-1 Duration curves for the electricity price in Eastern Norway at different exchange capacities

ascending order. It shows what proportion of the time throughout the year the prices are at different levels.

The red line (Base) shows the example with full exchange. Here we see that there are very few hours with zero prices in 2021, but a few more in 2040. The fact that we will have more hours with zero prices in 2040 is due to the fact that there is more unregulated power in the form of solar and wind energy in the Norwegian power system and not least in neighbouring countries.

If we go to the other extreme, the example of island operation, shown in the blue-grey line, we see two changes compared to Base. The first is that there are long periods of very low prices and an associated down-regulation of solar and wind. A downward regulation of solar and wind means that the power system is "full", so that this energy cannot be utilised, it is wasted. The second is that the curve rises more steeply. This means that there are also periods of very high prices.

The example of cutting the HVDC cables (yellow line) gives a result that lies between the other two examples.

The duration curves in the figure show that we will have lower average prices in 2021 and 2040 if we cut the transmission links in the year in question. However, as explained above, the projection cannot tell us anything about what price level we would actually have if we developed the power system without these connections.

What have been the price effects?
To show how prices vary over different weather years in the different examples, simulations have been carried out that assume an equal average price for all three (Base, Without HVDC and Island operation) over 30 different weather years. This is done by adjusting consumption and production so that the price level in each scenario is high enough to trigger new power production in 2040. In other words, it is assumed that market prices will trigger the investments in 2040.

This gives us the results shown in the figure below. It shows how prices vary depending on the weather year. The 30 historical weather years are from the period 1981 to 2010.

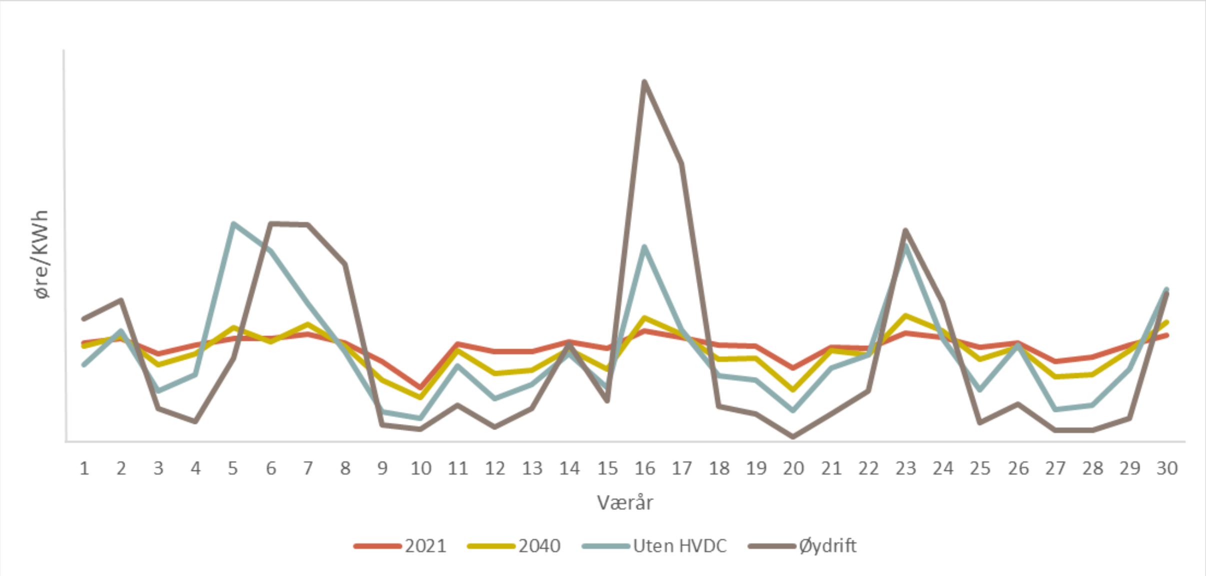


Figure 12-2 Annual average price for selected cases. Without HVDC and island operation are both in 2040.

The blue line shows the price variation given the power balance in 2021 and full exchange. The other lines show the price variations due to the weather years in 2040 for the examples with Base (full exchange), Island operation and Cut of the HVDC cables.

The figure illustrates that the less exchange capacity that is available, the more the system is exposed to weather uncertainty. The effects are naturally greatest in the example with island operation, but also significant in the example where the HVDC cables are cut. This means that you can have long periods of low prices, but also long periods of very high prices. In other words, prices become less stable and less predictable over the years the less exchange capacity we have.

What do changes in the power balance mean for prices?
We now go on to look at what changes in the power balance mean for the price effects in the two extremes, Base and Island operation. The simulation has not been performed for the HVDC example, but the results would then have been between the two extremes. The main conclusion that the power balance matters more the smaller the exchange capacity is, stands.

In the figures below, we show duration curves for prices in Eastern Norway in 2040 for both examples for different variations in consumption and demand. We have also looked at what the variation in demand flexibility may mean.

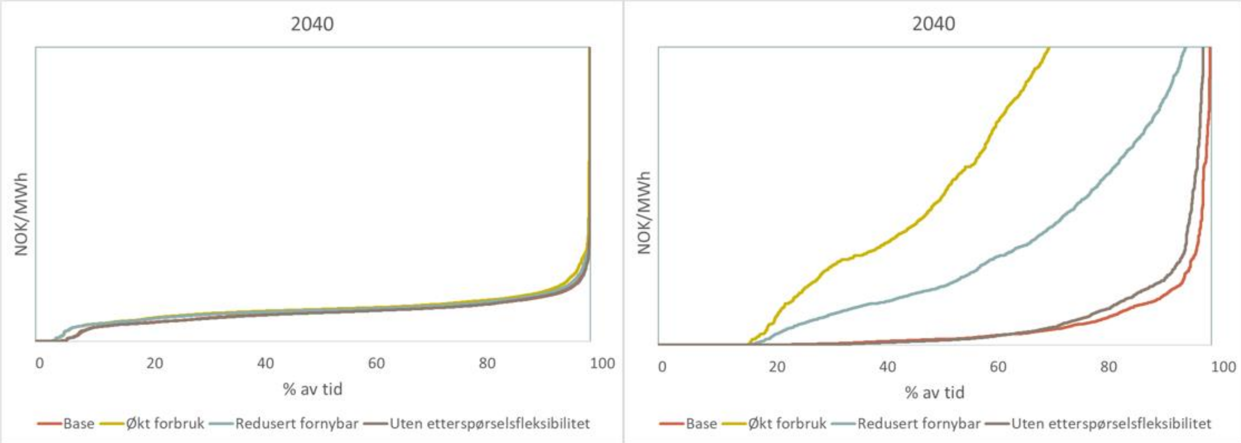


Figure 12-3 Duration curves for price, to the left for changes in Base and to the right for changes in Øydrift

In both examples, the same changes in consumption, production and flexibility have been assumed and compared with the original projection shown earlier. Here it is clear that in the example with full exchange, changes in the power balance have a smaller effect on price formation.

In the island farm example, however, we see that changes in the power balance have a significant effect on price formation. An increase in consumption or reduced production can lead to very high prices over long periods of time. Small changes have a significant impact on the average price. In island operations, the development of new production must therefore closely follow consumption trends over time.

The HVDC example will give results between these two extremes.

What do changes in the European price level mean for Norwegian prices?
We now look at the impact of increased European price levels on price formation. We will look at the two examples Base (full exchange) and Cut the HVDC cables. In the island operation example, we have no connections abroad and, as previously mentioned, prices are not affected by the European price level.

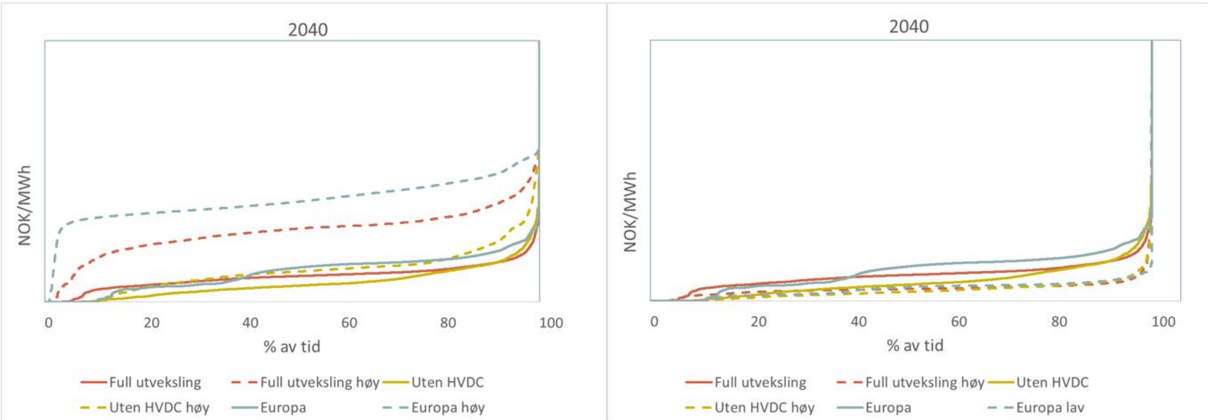


Figure 12-4 Duration curves for changing price levels in Europe

In the figures above, we look at the consequences of a dramatic change in price levels in Europe, as we have seen in recent years, for prices in Eastern Norway in 2040 in the figure on the left. The European price level is shown by the blue line. A "normal" European price level is shown by the solid line, and a high European price level is shown by the dashed line. Similarly, a trend of falling European prices is shown in the figure on the right.

The consequences of the changes in the European price level are shown for Base in the red lines and similarly, the consequences are illustrated with the yellow lines for the example of cutting the HVDC cables.

It is clear that the European price level is important in both examples, but with a far greater impact in the case of full exchange than in cutting the HVDC cables. There is a change in "cutting the HVDC cables" because the European prices are partly transmitted through the transmission links Sweden and Finland have with their neighbouring countries, but the effect is not as strong as when we have reduced transmission capacity as dramatically as in this example.

Another important point to see from the figures is related to Norwegian competitiveness. We are interested in the relative difference between Norwegian and European prices. We can see from the figure on the left, which shows the consequences of a very high European price level, that the difference between prices in Norway and Europe is increasing. This means that Norwegian competitiveness compared with European competitors is not necessarily worsened by higher European prices.

The conclusions we draw from this assessment of the importance of transmission links for price formation are

- Exchange capacity to neighbouring countries has a significant effect on price formation in Norway
- The power balance in Norway has a greater impact on price formation the lower the exchange capacity is
- With reduced exchange capacity, prices will be very sensitive to changes in the weather

This has some implications for the further development of the power system for prices. A larger power surplus will contribute to lower prices. If we build more transmission capacity abroad, this will lead to higher prices as long as prices in our neighbouring countries are higher than in Norway. The strongest overall effect depends on the size of the increase in power surplus vs. transmission capacity.

12.4 New power production does not come by itself

Both the Energy Commission (NOU 2023: 3), Statnett (Statnett 2023) and Kraftløftet[48] refer to the need for more renewable power in Norway. Our work also shows the need for a good power balance to ensure competitive and predictable prices. It is not automatic that commercially profitable investments will be realised. To conclude this chapter, we will point out a few barriers that indicate that it cannot be taken for granted that new power production will come on its own.

12.4.1 Capital and financing

Increased power production is only possible if new power plants can be financed through equity and loans. For both sources of capital, it is crucial that the projects are profitable so that banks and investors know that they will get their money back. The most important framework condition for investments to be realised is that they are profitable, both in business terms and in social terms.

Investments in new power generation require a lot of capital, and it takes many years before the players recover the money they have invested. An investment in new power generation therefore involves considerable financial risk. The degree of predictability, both in terms of revenues, costs and framework conditions, is therefore important for investors' assessment of risk. Well-functioning

[48] https://www.regjeringen.no/no/aktuelt/slik-skal-trepartssamarbeidet-sikre-okt-krafttilgang-raskere/id2967860/

future markets that can redistribute risk are essential for players to be able to make the investment decisions that best serve society.

12.4.2 More volatile markets

Our analyses show that future power prices are volatile, which increases the risk for investors and thus represents a barrier to investing in new capacity.

A well-functioning wholesale market is a prerequisite for realising the transition to renewable electricity. At the same time, pricing with a high share of renewables entails different situations and challenges for end users and power producers.

A high share of renewables will result in greater price fluctuations in the market. Price fluctuations are an advantage for flexible production and consumption, and the price signals in a system with a high share of renewables thus provide incentives for investments in precisely the type of flexible production, storage and consumption that will be an advantage for a renewable power system. We are already seeing this happening, for example, Norwegian power producers are investing in power capacity in hydropower production. This type of investment is intended to supply power during hours when prices are high. In this way, the price signals in the market contribute to investments that increase security of supply and mitigate price peaks.

At the same time, an unpredictable price will be demanding for investments in unregulated power, which the market is supposed to facilitate. If the price in the market becomes highly unpredictable, this will entail increased risk and lower present value in investment projects where production cannot adapt to the price level. Uncertain and variable price levels can also increase the balance sheet costs for unregulated power, which further reduces profitability.

How production, consumption and infrastructure develop together in both Norway and Europe is central to the consequences of the transition.

12.4.3 Unpredictable processes and framework conditions

Those who invest in and provide loans for power generation are mostly professional players, such as power companies, industrial companies, banks, pension funds and various funds. What they have in common is that they mainly manage other people's money - shareholders, depositors, pension customers or fund customers - and are accountable to them in terms of returns and not losing money.

Both lenders and the companies that invest have therefore developed expertise and systems for assessing risk in the projects they are considering. Experience has shown that it is easier to assess risks related to factors that are relatively easy to quantify, such as changes in supply and demand, prices of input factors and end products or variations in weather conditions, than major 'systemic changes', such as changes in framework conditions or the outcome of political processes.

At the time of investment, investors therefore place great emphasis on knowing the framework conditions so that they can calculate the profitability of the project. It creates uncertainty and great risk for investors if the framework conditions change significantly after the investment decision is made, reducing the project's profitability. Predictability is therefore important to make it attractive to invest in new power generation.

12.4.4 Uncertainty about consumption development

The power balance and thus the price level depends not only on the development of production, but also on the development of demand. There are many ambitions to increase the use of electricity, both for the conversion of existing energy use, especially in industry, and for consumption in new industries, such as battery production and hydrogen. This development in consumption is also largely politically driven, as climate policy and industrial policy instruments are required to implement the transition. Uncertainty about whether the assumed increase in consumption will actually materialise can be a barrier for power producers, as this increases uncertainty about price levels and thus the profitability of future power production. At the same time, assumptions about price levels are also a prerequisite for consumers. If the supply side grows at a different pace than the demand side, market prices can be very low or very high. If prices are too low, investments in production facilities will not be profitable. If prices are too high, it will be expensive to be an electricity customer. With uncertainty about how consumption and production will develop in the future, there will also be increased risk in the projects on both sides.

12.4.5 Lack of profitability in new technology

Sustainable energy production must be profitable without subsidies. It is therefore important to choose cost-effective technologies. At the same time, there will be a need for temporary support programmes to mature new technology and thereby achieve cost reductions in the technology over time. To enable this, it may be necessary to consider targeted measures, such as the government's offshore wind support programme.

Up to 2030, hydropower, onshore wind and solar power are the most realistic to develop in terms of time and cost, but conflicts of interest mean that it is uncertain how much can be realised in practice. In the longer term, there is great potential in offshore wind, but the cost level appears to be high for the time being. Interest in nuclear power appears to be growing in Norway, but there is little indication that it will be realistic in the next 10 to 20 years. When the European energy system will contain a significant proportion of non-regulatable power from solar and wind, this will provide opportunities for increased value creation for Norway through cheap imports and good utilisation of the characteristics of regulatable hydropower.

To ensure low and competitive prices in the long term, and also to protect Norwegian consumers from the largest price fluctuations, the most important measure is a policy to ensure a lasting power surplus. Achieving a strong power balance is a long-term measure and requires a number of political choices, including those related to land use, natural interventions and any need for support programmes.

A future demand for power could also be located in countries outside Norway. In addition to covering the Norwegian market, the production of renewable energy could therefore become an export industry and replace some of the value creation from the current export of oil and gas. A long-term plan should also include ambitions for the extent to which some of this need can be covered by Norwegian power production.

12.4.6 Taxation that affects investment decisions

Taxation that affects the profitability of investments and predictability for investors regarding the type of tax imposed are important framework conditions. The negative reception in the power industry and among investors of the proposed changes to the resource rent tax rates, as well as the new proposal for the introduction of onshore wind power without prior consultation until autumn 2022, underlines this. If special taxes are introduced on power generation that affect the profitability of the projects, this will be a barrier to new investments.

In 2022, a new high-price contribution was also introduced on income from hydropower production, where the rate was set at 23 per cent of the electricity price that exceeds NOK 0.70 per kWh. See chapter 6.3.2 for details on the high price contribution. In the proposed state budget for 2024, the government has proposed that the high price contribution will be discontinued from 1 October 2023. The high price contribution means that marginal taxation on income during hours with high prices will be high. This particularly affects incentives to invest in power in hydropower plants, as these are projects that will supply power during hours with high prices. Many planned future hydropower projects are in this category.

12.4.7 Lack of will and ability in the EU to keep up the pressure on the energy transition

The EU has high ambitions for its green transition. This is positive for both the climate and the value of the Norwegian renewable energy system. However, geopolitical challenges such as war and conflicts, or major pressure in supply chains for technologies and raw materials, can make it extra challenging and costly to realise the ambitious plans. In Norway, we will be affected by Europe's ability to implement the planned energy transition, cf. the scenarios earlier in this chapter.

12.4.8 Licence processes, access to land and social acceptance take time

The impact of energy production on nature is often considerable, and this almost always leads to conflicts of interest. Several government-appointed committees have emphasised the need for more efficient licensing processes, most recently the Energy Commission NOU 2023:3. Today, the licensing processes for the development of major power production and grids take many years. All major developments require thorough impact assessments of environmental and social impacts, among other things. Many interests and bodies must be consulted before a licence is granted for the development in question, and possibly also on the final terms of the licence. The licence process must also be coordinated with the development municipalities' planning process. Licence holders with special protection, such as Sami reindeer husbandry, must be safeguarded in accordance with international obligations. This requires good studies and thorough decision-making processes leading up to a licence, and that these are legitimate and can support acceptance of the projects that are granted a licence. However, even with extensive licensing processes, social acceptance of onshore wind power in particular has been low in recent years. Within this category, there are a number of commercially profitable projects.

Improved cooperation between local and national authorities, including through earlier involvement, and between the licence applicant and the affected licensees, including Sami reindeer husbandry where relevant, appears to be an important key to preventing future and time-consuming conflicts. If potential conflicts can be taken into account and perhaps resolved early in the process, this will obviously affect the time spent on the licence process. It may also be the case that the relevant development municipalities have limited resources to handle a licence process, and that this can distort and delay the process. When applying for watercourse regulation under the Watercourse Regulation Act, the relevant development municipality is entitled to have the costs of additional planning resources covered in order to safeguard the municipality's interests in the licensing process. This may also involve necessary coordination with municipal planning processes. One possible measure to consider to facilitate the licensing processes could be to ensure that the local development municipalities have such resources in all major licensing processes for the development of production or major networks, not just for watercourse regulation.

Part 3: Analyses of possible measures and changes

In Part 3 of the report, we present the results of the committee's analyses of the current market model against various alternatives and of around 50 different measures that could affect prices, price formation or electricity customers' costs. Inspiration for alternative market models and possible measures has come from the mandate, input to the committee, the political processes both in Europe and in Norway, research, reports and analyses the committee has come across, newspaper articles, comments in social media and to some extent from the committee itself. On this basis, the Committee drew up a list of alternatives and categorised these into three main groups: i) measures that target price formation in the wholesale market, ii) measures that aim to correct any market failures in retail markets, and iii) measures that in some way involve a financial transfer to electricity customers.

For the measure analyses, the aim has been to describe the likely effects of each individual measure, on prices, the power system and society, in an objective and neutral manner. We generally do not take a position on whether the effects are positive or negative. For one and the same effect of a measure, different stakeholders may have different views on whether the effect is attractive or not. The committee has interpreted the mandate to mean that we should analyse the effects of various measures, but not necessarily make recommendations on what should or should not be implemented. Ultimately, these will have to be political judgements.

Assessment of the measures requires knowledge of the power system and the power market. Part 1 of the report is therefore a key foundation for the analyses in Part 3, especially for measures relating to the wholesale market.

Nevertheless, a few measures appear to be more relevant and less controversial than others in the current situation. They are typically characterised by the fact that they can be implemented relatively quickly, have low costs, both financially and in terms of security of supply and resource utilisation, and do not require extensive regulatory intervention. On the other hand, none of these can have a major impact on electricity customers' costs, either alone or in combination. In the big picture, however, there are many indications that these may be small steps in the right direction. Specifically, this involves various measures for better information between wholesale market participants and the authorities, information aimed at households and other relatively small electricity customers (particularly regarding price hedging), and finally a measure to contribute to better liquidity in so-called EPAD contracts (see section 15.4.9).

Chapter 13 explains the methodology the committee has used for the assessments. In chapter 14 we discuss the characteristics of the current and alternative market models in light of a very high proportion of renewable energy with low or no marginal costs. Proposals for measures to improve the wholesale market are summarised in chapter 15. Proposals that can reduce any market failure in the retail markets are discussed in chapter 16while issues related to different types of electricity subsidies are discussed in chapter 17.

13 Methodology for evaluation

The aim of the analysis is to look at measures that can contribute to lower, more stable and competitive prices for households, industry and business, and ensure investments in renewable energy. The committee does not make clear recommendations, but wishes to provide decision-makers and others with a basis for making their own decisions based on the impact of the measures. We have different approaches. How will the measure affect the market itself? We assess the measures' effect on price, security of supply and investment behaviour. We look at the social aspect with distributional effects and the redistribution of the measures. The measures also have a legal aspect. Can they be implemented within the current legal framework, including international obligations? The measures that involve subsidies or other types of electricity support will also affect the efficiency of the tax system and public budgets.

Parts of the analysis are based on economic theory. This does not mean that the conclusion is always a market that is as free as possible. Market failures should be addressed with measures, and in many cases there will be a trade-off between market efficiency and inappropriate distributional effects that should be addressed with measures. Electricity subsidies can also be justified in socio-economic terms when the transition costs for businesses are high or the consequences for households are significant. The committee believes that distributional problems are real and central problems, and that it is not sufficient to look at socio-economic efficiency. We should also look at developments in the EU to see which measures can be implemented.

We do not analyse the effects of lower and more stable prices for households, businesses and other customer groups. For a more detailed description of the challenges for electricity customers and investments in new consumption, which such measures may be aimed at mitigating, see Chapter 8 on the retail market and Chapter 14.4.

Electricity is a limited resource. Virtually all new and existing power generation has consequences for nature and various interest groups. The measures must also be seen in the context of the impact on nature and Norway's climate commitments discussed in the previous chapter.

Measures that may seem appropriate to implement may be in conflict with current rules. The Committee has not assessed or proposed changes to current rules or obligations.

Electricity is classified as a commodity subject to the market rules of the EEA Agreement. However, the EEA Agreement does not definitively determine that electricity shall be a product subject to the market rules. The EEA Contracting Parties are granted a certain degree of discretion to reclassify electricity as a necessity good in line with other necessity goods that are not subject to the market rules, such as water and sewerage. In a memorandum prepared for the Committee, Professor Erling Hjelmeng writes the following about redefining electricity as a good that is not subject to the market rules (Hjelmeng 2023):

> *"Furthermore, we can look at how the delivery of other necessary goods is organised, such as water and sewage, or the waste sector. In these sectors, there is largely municipal control over supply, and fees are politically controlled (based on a principle of cost recovery). However, such a move would largely entail a reversal of the liberalisation that took place with the Energy Act in the early 1990s, and could also face other challenges in EEA law, both of a legal and practical/commercial nature (given the connection to the European market through international cables). Nevertheless, it will probably be possible under the EEA Agreement to redefine electricity as a good of necessity and a service of general economic interest, which will at least partially override the market rules."*

It follows from this that it is probably possible to redefine electricity from being a commodity subject to the market rules in the EEA Agreement to a necessity good that is less subject to these rules. A redefinition could, for example, probably put the market participant principle out of play, but some other obligations under the energy market packages and state aid rules will, in the Committee's understanding, probably still apply. Therefore, the actual room for manoeuvre that can be created with such a move is unclear, and identifying it will require further investigation. The room for manoeuvre for treating electricity as a necessity may be narrower after the fourth energy market package (Mathisen 2023). Redefining electricity as a necessity good that is subject to market rules to a limited extent appears to be a comprehensive measure that involves changes not only to the retail and wholesale markets, but also to how the entire sector is organised. Due to time and capacity constraints, the Committee has not considered in detail how this could be done, what it could mean for prices, costs and security of supply and what legal and practical barriers it would entail - or whether the desired effects can be achieved with alternative measures. In the following, the Committee therefore discusses measures based on electricity being defined as a commodity covered by the EEA Agreement's market rules.

13.1 Five questions to assess the impact of measures on the power system and society

In our analysis of the measures, we ask various questions to address the effect of the measures, to the extent that it is appropriate for the assessment of the measure. In this chapter, we will elaborate on the questions summarised in the figure below.

Figure 13- 1 Questions to assess the impact of a measure on the power system and society

13.1.1 Description of the measure

Many of the measures considered overlap, or have many of the same mechanisms and have very similar effects. We have attempted to make an appropriate categorisation.

Many measures can be designed in slightly different ways. We have generally endeavoured to describe the design in such a way as to make them as appropriate (given the committee's mandate) as possible.

13.1.2 What is the price impact of the measure?

Who is the measure aimed at? Different consumer groups will have different abilities to deal with high and unstable prices. The effect of a measure may be different for different groups. The legal effects considered are also different. How are prices affected in the short and long term? Will they be lower, more predictable, more competitive? In the power market, supply and demand must be in balance at all times; in simple terms, this is the most important task of prices in the short term.

In a hydropower-based system such as Norway's, prices over the next few days, weeks and months are also important in the producers' assessment. The ability to store water in reservoirs gives us advantages in the short term, but there must be enough water (energy) in the reservoirs to meet demand through, for example, a winter. They can choose whether to produce today or tomorrow or in two months' time. Wind or solar power producers do not have that option. How prices are affected is therefore important for the producers' utilisation of the reservoirs. The long-term prices that are expected over the years are important investment signals.

For consumers, the short-term and prices over the next few months will naturally be important for how they adapt, but the long-term prices will be relevant when considering whether to implement energy efficiency measures, for example. Unstable, but on average low prices can be handled differently than high and stable prices, and may mean different investment needs for producers and consumers. Electricity suppliers and other intermediaries between producers and consumers will also be affected when price measures are implemented. Much of the power in Norway is traded via a power exchange, and both short-term and long-term trading in the financial market could be affected.

Competitive prices will be a relative concept, and depend on what the price is abroad. It may also be a relevant question about domestic competitiveness between regions in Norway in situations where there are large differences between price areas in Norway.

13.1.3 How did the initiative affect the behaviour of actors along the value chain?

In the market, price is the rationing mechanism. It sends a signal of scarcity at higher prices, and a signal of surplus at low or even negative prices. Negative prices occur when the producers' start and stop costs to produce are higher than producing at a negative price, where the producers have to pay to deliver the electricity to the grid. High stopping costs can also be due to subsidised production and therefore continue production despite the price in the spot market. When the price changes, this will therefore affect the behaviour of all players in the market. When the price signal differs due to the introduction of a measure, it is necessary to look at how the behaviour of consumers affected by the measure and those not affected is affected. This also affects consumption patterns and incentives for energy efficiency. Price changes due to a measure will also affect reservoir utilisation, incentives for new production and the supply of new contracts. There are several stages in the distribution of electricity. Electricity suppliers buy electricity and sell it on. Intervention in this market will naturally also affect their market conditions. We look at how the behaviour of electricity suppliers is affected by changes in risk and costs and by the range of products on offer.

13.1.4 What are the consequences of behavioural changes for the power system?

The price signal is an important signal for how resources are managed. If it changes, it affects security of supply, power security in the short term and energy security in the longer term. Measures in the current market can affect resource utilisation both positively and negatively. We are part of a European power market. A change in price in Norway could also affect trade with other countries. It may also change how our neighbouring countries act, including politically.

13.1.5 What consequences will the change in the power system have for society as a whole?

Measures in the power system have consequences for society as a whole. If the price is changed through direct regulation or transfers, the distributional consequences of the measure are realised. Who wins and who loses, producers, consumers, suppliers, the state or owners?

Energy consumption in general is responsible for major greenhouse gas emissions. Changes in electricity prices may affect consumers' consumption and choice of energy source. Prices affect existing and new industries, both producers and consumers of electricity. The development of new production requires that land and nature considerations must be taken into account, and we also have international climate commitments to consider.

All types of transfers will affect the efficiency of the economy, and will also affect the efficiency of the tax system.

13.1.6 What barriers exist to implementing the initiative?

The energy market is regulated both by national legislation and internationally by EU regulations, and the measures reviewed must be assessed in relation to these regulations. The legal framework will not be absolute, partly in the sense that it can of course be subject to change in response to changing political assessments, partly because the rules are subject to interpretation and development in practice, and partly because there are a number of exceptions to the main rules, which are generally restrictive. It must also be taken into account that the legal framework for the energy sector is changing in the EU, and this may also have an impact not only on Norway's room for manoeuvre, but also on whether Norway needs to respond to measures introduced in the EU.

It is beyond the scope of the committee to provide a complete review of all possible legal consequences of various measures. The discussion of possible legal frameworks is limited to mentioning some key EEA law issues that must be assessed in more detail for the measures in question.

Administrative barriers mean that the measures may have financial and practical consequences for the public sector, power producers and suppliers and end users. Measures that require public support will have to be prioritised against other purposes. In such an assessment, we are not only interested in whether measures will result in expenses for the state, but also in the benefits and costs of the measures for society as a whole. It should also be considered whether the same objectives can be achieved in a less costly way. The committee's assessments are intended to contribute to a sound basis for decision-making by systematising and highlighting the effects of various measures.

Administrative barriers are not absolute, but in many cases they can still prevent a programme from being implemented. Practical examples are that the administrative cost of a measure is high or difficult to implement. This also involves a time perspective; some solutions will require time to be implemented.

14 Model for pricing when the share of renewables is very high

The power market must ensure that production and consumption increase in both the short and long term. The short-term task is solved by the market generating price signals that reflect the supply of and demand for power hour by hour. The players adapt to the resource situation when they submit buy and sell bids depending on the price. The long-term task is solved when both producers and consumers make decisions on new investments based on their expectations of prices in the long term.

14.1 What happens when the share of renewables increases

With unregulated power generation where the input factor that produces the power has no alternative value, such as solar power and wind power, producers will produce power hour by hour as long as the price they achieve is above zero. They cannot store the input factor to use it later when its value is higher. With the current pricing mechanism - marginal price - it will be profitable for the players to offer solar and wind power as long as the price is higher than zero.[49] A wind power producer who only wants to sell if the price in a specific hour is high risks not being able to sell production and thus loses out on income if the spot price ends up just below the producer's bid.

In Europe today, power generation is largely fossil fuelled, and the price is set by the marginal production cost of gas and coal-fired power generation, which consists of both the price of fossil fuels and CO_2 quotas. When production to a greater extent becomes solar and wind power, these technologies will not set the price if production is offered for sale as long as the price is above zero. With the current mechanism, it will then be consumption that sets the price, as shown in the highly stylised sketch below. To the left is a highly simplified illustration of the current situation in Europe, where demand is given by the falling curve. The market price is determined by the costs of the grey power plant, because this is where the demand curve meets the supply curve given by the marginal costs of different power plants.

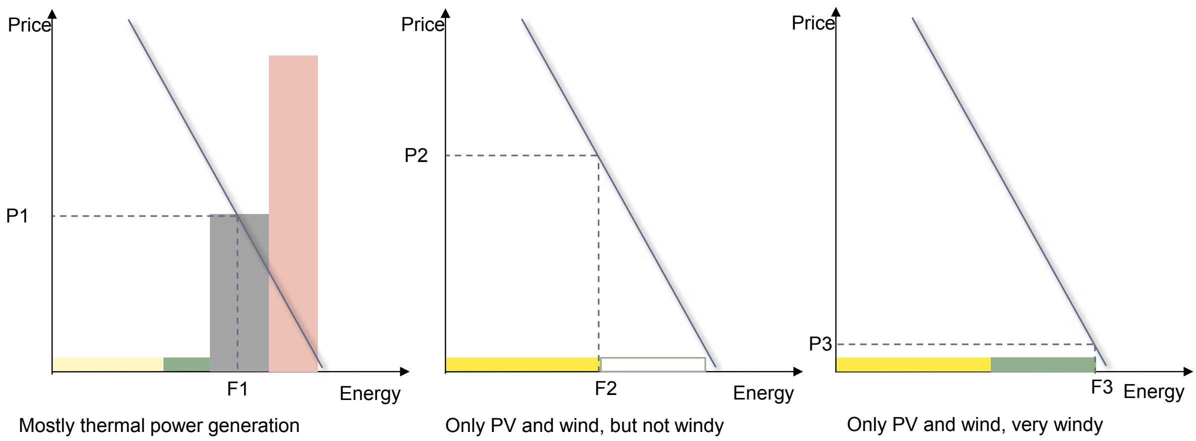


Figure 14- Sketches of an electricity market with different supply sides

In the centre figure, we have a power system consisting solely of solar and wind power, but depicted in a situation where there is no wind at all. Since the demand for the low price at which solar energy is offered (given by the height of the yellow 'pole') is significantly greater than the supply. The dotted

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49 If producers have costs for e.g. maintenance that depend on actual production, production will be offered at something above zero. If they have costs to adjust production downwards, producers may from time to time also be willing to pay to produce. If overall consumption is lower than the supply from producers willing to pay to drop and shut down production, the result will be negative prices. If support mechanisms to secure investments are designed so that the support paid out depends on how much is produced, regardless of price, producers may be willing to pay almost the full amount of support to produce.

vertical line indicates how much solar is available. The result is a price equal to P2, and consumption is F2. In practice, this means that it is the demand and willingness to pay for a given volume of available power that now sets the price. This is in contrast to the figure on the left, where a price intersection between production cost and demand sets the price and the volume sold. If we had a gas-fired power plant or something else as a reserve, such as the red power plant in the figure on the left, we would still not get a higher price than P2, as the marginal cost of the reserve power plant is even higher. If we had also had the grey power plant available in the middle example, the price would have been P1 - but then we would no longer have a power system where all power plants have a marginal cost (close to) zero.

The figure on the right shows the same demand as the one in the centre, but here there is no longer no wind. In this sketch, demand at the low marginal cost is also greater than supply. But because the wind is blowing, we can have a significantly higher consumption (F3) and lower price (P3). To make the figure as simple as possible, demand is drawn as the same in all three situations. The two situations in the middle and on the right show how the demand side in this (stylised) power market must adapt to production, while in the figure on the left, production is more likely to adapt to consumption.

The sketches emphasise the consequences of a very high proportion of production with low or no marginal costs. So far, the power system based on fossil fuel power generation in Europe and regulated hydropower in Norway has meant that in both the European and Norwegian markets, production has largely been adapted to the level of consumption. With a greater proportion of unregulated power, consumption will have to be adapted to a greater extent to production.

The sketches above are illustrations. One of the things that will have to happen when an increasing proportion of production becomes unregulated and the cost of keeping older power plants based on gas or coal in reserve rises, is for market players to develop their own flexibility, for example to better manage heat production in buildings or develop industrial processes that are well suited to adjusting their own production in line with energy supply.

Consumers are signalled this through prices, and are incentivised to use less power when prices are high and more when prices are low. Consumption that is adjusted to the price level will also help to even out prices. As described earlier in 12.1 consumption for green hydrogen production can have a greater impact on prices in the European market. Other sources of flexibility in the power market could include batteries, pumped storage, production of heat for heat storage, or production of gases other than hydrogen.

Investments in power generation will depend on a price level that makes the project profitable over time, and is therefore dependent on the players' long-term price expectations and their willingness and ability to bear financial risk. It is not a given that price expectations are not sufficient to ensure 'enough' investment on the supply side. But it is also not a given that the players' expectations and risk appetite are sufficient to ensure an electricity balance that is politically desirable and that balances the consideration of competitive prices and the protection of nature and other interests. In Sweden, Svenska kraftnät has produced a report that discusses whether there is a need for a capacity market or similar (Svenska kraftnät 2023). Statnett has announced that it will publish a report on future market design in autumn 2023.

14.2 Is there a better alternative to the current pricing model?

The current pricing model in the wholesale market is structured and constructed so that the individual players' decisions on production and consumption go up (balance) simultaneously , cf. chapter 5.5, 6.1.1 and 6.6. Three different alternative models for price setting are considered here: a division of the wholesale market into two parts according to different technology groups, the pay-as-bid model, and the Norwegian model prior to the Energy Act of 1990. Pricing in Norway affects trade with other countries. Any changes will therefore require a process with the neighbouring countries, which also have interests to be safeguarded. Our analysis focuses on the economic characteristics of the alternative models.

In connection with the power market reform in Europe, some countries have put forward proposals to change the pricing mechanism in the wholesale market. The proposals for alternative wholesale market models were motivated by the desire to achieve lower retail prices by limiting the revenues of those generators that made high profits under the marginal pricing system and redistributing this value to end users in the form of lower electricity bills. However, the proposals were not followed up by the European Commission in the EU market reform, where the EU will choose to retain the current marginal pricing model. The Committee's assessments are subject to the proviso that the alternative proposals are only sketches and not fully developed concepts.

14.2.1 Division of the wholesale market

In 2022, the Greek authorities proposed a model where the market is divided between regulated and non-regulated power. Various non-regulatable technologies will receive revenues based on production costs, so their revenues will be lower than in the current model. Regulated power has a greater need for price signals so that production can be adjusted according to demand, and this technology group therefore receives revenue based on marginal pricing just as in the current system. Consumers pay an average of a regulated price (for unregulated power) and a marginal price (for regulated power). The retail price will therefore be lower than in the current system. In this way, the Greek proposal can be understood as an attempt to create a form of basic rent tax (where unregulated production will only receive the income they 'need') in combination with an attempt to distribute the basic rent to consumers via a regulated average price. The committee has received several submissions that, like the Greek model, propose a division of the wholesale market between different technology groups in order to achieve lower retail prices (Golombek 2023, Roland Consulting 2023).

The Greek model has some similarities with the Norwegian resource rent tax for hydropower, but there are also differences. While the Greek model will categorise different power plants by technology group, the Norwegian tax system is to a greater extent designed for individual treatment of each hydropower plant. In Norway, for example, hydroelectric power plants with low regulation capacity will generally receive lower revenues than power plants with high regulation capacity, even if the power plants belong to the same technology group. The basic rate of return tax for hydropower treats both differences in income related to e.g. regulation capacity and costs for each individual power plant individually. A significant difference is that the current wholesale market model does not have a built-in distribution mechanism similar to that proposed by Greece. However, the electricity subsidy in combination with the resource rent tax is an example of a distribution mechanism that can achieve the same result as the Greek model without changing the wholesale market model. There would also be greater political room for manoeuvre to target support to different customer groups than with the Greek model, which would support all customers regardless of customer group and relative to consumption.

Successful implementation of the Greek model could at best result in the same wholesale prices for regulatable power as would be achieved with the current system, and a surplus from unregulated power that could in principle correspond to the proceeds from a resource rent tax. To see this, we must first distinguish between the price to producers and the price to electricity customers. Operators with unregulated production receive a price based on estimated production costs that are independent of market conditions, while those with regulated production receive a price determined by the intersection of the supply curve and the demand curve, as in the current marginal pricing model. We can use the sketch above on the left as a starting point Figure 14-. If we remove the non-regulatable technologies (solar energy and wind power) from the supply curve, we must also assume that these cover part of the demand. To find the remaining demand that must instead be covered by regulated technologies, we can move the vertical axis to the right, all the way to the grey power plant. Then we have removed equal amounts of supply and demand from the 'remaining' wholesale market, and the wholesale price received by the dispatchable power plants becomes P1.

The question is then whether consumption, which is faced with a lower price than P1 in the retail market (as the lower price for unregulated power pulls down the end users' average price), will 'only' be F1, or whether consumption will be higher. In the short term, it is fairly certain that many consumers will not or cannot adjust their consumption. For these customers, the demand curve is in reality a vertical line. However, total demand in Norway is not a vertical line, cf. Figure 62. Figure 6-not even in the short term. The result may then be that demand increases so that, with reference to Figure 14- we must also activate the red power plant. In that case, we will have a situation where we use more power than there is a willingness to pay for, resulting in a socio-economic loss. Therefore, the Greek model will lead to less efficient resource utilisation and a lower socio-economic surplus than the current model does - in other words, the values available for redistribution will be less than with the current system.

Looking further ahead, more people have the opportunity to react to price signals and the demand curve becomes more elastic. This is because when making investments, such as building a home, an office building or a factory, many will take into account experienced or expected changes in electricity prices when deciding whether to utilise new and more energy-efficient technology. Once the building is completed, it takes significantly more to upgrade to new technology. Faced with an electricity price that is lower than society's marginal cost of power, electricity customers will have less incentive to make investments that could reduce their energy costs (such as energy efficiency improvements or their own solar cells on the roof). The Greek model could then have similar effects on security of supply, the power system and society in general as a permanent electricity subsidy or maximum price scheme would have (see Chapter 17).

If demand exceeds available production over time, the market will no longer be able to fulfil the task of balancing production and consumption. This creates a situation that will sooner or later require more direct control of the market, where power is distributed according to a principle other than willingness to pay, for example through quotas or some other form of rationing. It may be possible to raise the regulated price for unregulated power production, so that the end-user price increases and consumers receive a stronger signal to react to shortages. However, this would bring us closer to a model similar to the current one.

As the Greek proposal stands, it is also unclear how the model will work if the wholesale price remains below the total costs of unregulated production for short or long periods. There would then be no surplus to distribute, but a deficit that the state would have to cover.

In the long term, an average price to electricity customers will probably also increase the uncertainty associated with investments on the supply side, as pointed out by, among others, Golombek (2023). If the regulated price for unregulated production does not cover the total costs, there is no reason to believe that anyone will maintain capacity over time.

The Greek proposal does not answer all questions about how the model would affect international trade in electricity. One risk is that lower wholesale market prices in the country where the model is implemented will lead to associated neighbouring countries wanting to import more from the country that has now become a low-price area. We have seen this dynamic, for example, as a result of the temporary intervention by Portugal and Spain to subsidise their retail prices through the wholesale market during the energy crisis. This led to increased power exports from Spain to France, so that the Spanish state in practice also subsidised French consumers (see Chapter 11). However, in a wholesale market model inspired by the Greek model, it is possible that this can be circumvented by separating national retail prices from the price at which power is exported (Golombek, 2023). If the Greek model had been introduced at European level, this could have created a risk that Norway would have become an area with relatively uncompetitive prices. The reason for this is that Norway has a high proportion of regulatable power in its national power mix compared to many other European countries, so that through average the price offered to Norwegian end users could have been higher in Norway than in countries that have a higher proportion of power production in the unregulated category.

14.2.2 Pay-as-bid

Another model that is sometimes discussed is that producers should not be paid according to the marginal price principle, but according to their own bids in, for example, the spot market. In auction literature, the current principle is referred to as pay-as-clear, while the alternative is often called pay-as-bid. An essential characteristic of the power market is that several of the various sub-markets in the wholesale market have daily auctions. The same routines are followed every day. If you know that i) if I offer my production cheaply enough, I will sell it, and ii) I will only be paid as much as my own bid, regardless of whether my bid is the lowest or the highest accepted bid, the best strategy will be to guess what the price will be in the highest accepted bid, and possibly bid slightly below that. At best, the prices will then be approximately the same as in the current system. With the pay-as-clear model in the current system, there is nothing to be gained by bidding tactically in this way - on the contrary, offering production at marginal cost will maximise the producer's revenue. Since no one can guess the right price every day, and thus bid 'perfectly', with pay-as-bid you will find that from time to time producers with low costs will submit bids with prices above what is necessary to create equilibrium. These will then not produce, and instead more expensive power plants will have to be utilised. In the worst case scenario, this leads to less efficient use of resources and prices end up being higher than in the current system. This is probably the most important reason why pay-as-bid is not widely used in the world's power markets.

14.2.3 Before the Energy Act of 1990

Some have also advocated a return to solutions reminiscent of the situation prior to deregulation, for example with the state itself, or a small number of publicly owned companies, being responsible for the operation and planning of power plants in a defined geographical area. It is not obvious that the total costs or price level will be lower in such a system, but it may be easier to reduce the price variation for electricity customers. Electricity customers' access to long-term contracts will depend on policy.

Perhaps the most important change from the time before the reform of the electricity market is that the financial risk of investments was placed with the person who made the investment decision. Previously, local and regional companies had the monopoly and freedom to set the electricity price they needed to balance their books. As the prices then had to reflect the total costs, including depreciation of the power plants, they could not at the same time reflect the current supply of resources. In practice, a two-price system therefore developed, where industry with its own power plants and foreign buyers could buy Norwegian power cheaply if we had a good supply of resources one year, while Norwegian electricity customers otherwise faced a significantly higher price. Foreign buyers were faced with a price that actually reflected the short-term resource supply, while Norwegian electricity customers had to pay a price that reflected the total costs in the power system.

As we are going to see an ever-increasing proportion of unregulated power production in the power mix, both in Norway and in our neighbouring countries, it will be more important than ever that we are able to adapt demand to supply to a greater extent. We will then be dependent on a large number of individual electricity customers being able to adapt their consumption to the availability of resources. Although much of this adaptation can (and should) be automated, we need both control signals that electricity customers or their installations can react to, and the opportunity for profitability in actively managing consumption. It is difficult to see how this can be coordinated in practice without varying prices, since we do not have centralised information about which consumers can make adjustments when and to what extent.

14.2.4 Conclusion

The current system means that one price is set for all electricity production in an area, even though the power may be produced by a number of different technologies with different production costs. This price reflects the total resource supply and total demand. The system combines security of supply considerations with good resource utilisation. In this way, it contributes to the total costs of power supply being lower than they would be with alternative solutions. This is a strength compared to the alternative models the committee has assessed. The challenge is that the need for redistribution may be greater. In that case, there will be less risk and more to distribute when taking the current model as a starting point and removing the goal of redistribution from the wholesale market setup and instead treating it as a separate transfer between the state and the end user. In addition, the complexity of the market increases as more power generation becomes unregulated and also to some extent unpredictable. Production levels can change in a very short time, and this must be balanced with flexible consumption and storage solutions that react quickly to balance energy supply and consumption. Today's market organisation also allows for decentralised decisions. If a centralised player were to make all the necessary decisions - about who can produce and who wants to consume, how much and when - this player would have to be able to handle an enormous amount of information continuously. The administrative challenges would be formidable, and these also represent a cost to society. Based on these considerations, the Committee believes that the current system based on marginal pricing in the wholesale market appears to be the best alternative when the market has to manage the energy transition and the share of renewables increases.

14.3 What is needed to adapt the system to a high share of renewables

Facilitating an electricity system in Europe based on renewable sources is a major transition that requires the implementation of a number of solutions that will contribute to a well-functioning market. Much consumption is currently not flexible, new consumption that can be based on low prices (such as green hydrogen production) has not yet been scaled up, and technology development and investments are required to realise these solutions. The power system and the market are now at the very beginning of a transition period in which this development will take place.

In addition to technological solutions, the specific design of the power market (market design) is crucial. In Norway and the Nordic region, we already have a market that solves many of the coordination tasks it is supposed to solve, but changes are also required here. In a few years, the European spot market will be changed so that prices are set for 15 minutes at a time, compared with one hour today. This change is necessary in order for the system operators in the transmission grid to be able to plan ongoing operations as well as possible. As explained in chapters 5 and 6, this planning is critically important for maintaining a high level of security of supply.

Extensive tasks lie ahead for system operators, producers, electricity customers and electricity suppliers. The necessary coordination between production and consumption that can actually be managed without incurring huge costs places considerable demands on technology and solutions for communication and automation. Some of this already exists - such as the possibility for a service provider to control the charging of electric cars within limits set by the customer - but much needs to be developed.

With a steadily increasing share of renewables, there is reason to expect a period of greater variation and less predictability in power prices than we have been used to in recent decades. Increasing uncertainty has two contradictory effects on demand for price hedging, both from the consumption side and from the production side. The first effect is trivial - the greater the risk, the greater the need for and benefit of price hedging. The second effect is more complicated, but the starting point is that one must be prepared for the cost of price hedging to rise, cf. chapter 6.7. As a concrete example, we can look at margin requirements for clearing (see chapter 6.1.4) - they increase with increasing uncertainty and it becomes more expensive to participate in hedging markets. This means that the supply of hedging tends to fall with increasing uncertainty. Increasing demand and falling supply of hedging is not a favourable combination, and this is therefore a topic that the authorities must monitor closely in the future. Relevant instruments may be among the measures discussed in chapter 16 and 17, in addition to 15.4.9.

14.4 Impact on consumers in the transition to a high share of renewables

The wholesale market will go through a restructuring period where the expectation is an average higher price level. With the existing pricing model, this will mean that the revenues of power producers with low production costs will increase, while consumers face higher electricity costs, cf. also the description of the impact on companies' competitiveness in the scenario review above. Norway has a tradition of addressing high revenues in the power sector with resource rent taxation. If there is a desire to redistribute revenues from producers to consumers beyond the use of the resource rent tax, the room for manoeuvre will be limited by common European market and state aid rules, cf. the description in Chapter 16. Among the EU countries, the problem of redistribution has been a key topic in the discussion of the ongoing power market reform, but no agreement has been reached on how to solve this without creating unequal competitive conditions in the internal market.

Not only higher price levels, but also more volatile prices affect consumers of electricity. Flexible consumption will pay off in a system with greater price variation. Inflexible consumption will result in increased risk and higher costs. Large parts of consumption today must be considered to be relatively inflexible, both in households and businesses. As described in Chapter 8, electricity is a necessity for households, and also for much of the consumption in the business sector. Consumption in the business sector can also be fundamentally inflexible as a result of production patterns. Much of Norwegian industry today consists of industries with inflexible consumption, both in power-intensive industries and other industries where electricity is an input factor. For this type of industry, price fluctuations will be a cost driver. Not only industry, but also households and commercial organisations with large building areas should take into account in their future planning that the ability to adjust consumption over time will be valuable.

Access to price hedging opportunities will become more important in the future, as a measure to mitigate unpredictability and redistribute risk to those who have the lowest cost of bearing price risk. However, price hedging agreements will also price in the risk in future markets as a result of more variable price levels. Price hedging does not result in lower prices, and if future prices increase as a result of increased uncertainty, price fluctuations may increase the price of price hedging for customers.

15 Measures aimed at the wholesale market

Over the past couple of years, there have been many proposals for measures to reduce price levels, ensure stable and predictable prices, and ensure that we have competitive prices abroad.

In this chapter, we consider various measures that can be directed at the wholesale market that may have an impact on price formation. The measures aimed at the wholesale market have consequences for all consumer groups.

We assess the measures in line with the approach described in chapter 13. This means that we have looked at:

- **How can the programme be designed in concrete terms?**
- **What are the price effects of the measure?**
- **How does the measure affect the behaviour of actors along the value chain?**
- **What are the consequences of behavioural changes for the power system?**
- **What consequences will the changes in the power system have for society as a whole?**
- **What barriers exist to implementing the initiative**

We have also chosen to assess the effect of several of the measures in the short and long term. The short-term consequences of the measure correspond to its introduction as a crisis measure with a temporary duration. If the measure is introduced permanently, it is important to also look at the long-term effects.

To ensure the most robust possible assessment of the effects of the measures, we have assessed whether the measures are more or less appropriate depending on how the power system develops where it has been natural. To do this, we have used the scenarios described in chapter 12.2.

We have chosen to group the measures into a few main groups, where the measures will essentially have the same consequences. The main groups are as follows:

- Measures that reduce the utilisation of exchange capacity with other countries
    - Seasonal exchange capacity, throttling of export capacity at low utilisation rates, overriding the flow based on price, measures that permanently change the transmission capacity abroad, separate bidding area for exchange
- Measures that directly intervene in reservoir utilisation
    - Absolute reservoir restrictions, smart reservoir restrictions: LRV as a function of price and environmental costs, requirements for reservoir filling with quotas, levy on production when reservoir filling is low
- Measures aimed at price in the wholesale market
    - Energy options for consumption and production, power and energy guarantee scheme - energy option without trigger function, dual price: domestic and power exchange, rule if a share is traded outside spot on other contracts, Norway price - a price for consumption throughout the country, maximum price, stimulate liquidity in the futures market, Transmission capacity (domestic) beyond what is socio-economically profitable
- Measures that improve information in the market so that players make better decisions
    - Increased focus on security of supply in the manoeuvring regulations for reservoirs, better description of volatility in public price forecasts, better knowledge of price elasticity, information from operators to TSO and RME, public information about the

authorities' and Statnett's assessments, public information about the operators' adaptation in the event of very high prices

An important lesson learnt from the assessments that have been made is that measures in the first three main groups that directly affect the wholesale market should be thoroughly investigated before any decision is made to proceed with the implementation of the measures. There are several reasons for this:

- The interrelationships in the power system are many and complex, and the players make decisions under uncertainty as described in Part 1 of the report. This makes it difficult to assess all first-order effects of the measures, even just based on the current situation.
- In addition, over time, the second-order effects tend to "eat up" the first-order effects. For example, a measure that results in lower prices will make it more favourable to establish new activity that increases demand and prices. These dynamic effects are described in more detail in Part 1 of the report.
- The assessments are further complicated by the fact that the energy systems are undergoing major restructuring and the uncertainty about our own country's development in terms of the power balance, and not least the development in our neighbouring countries' production mix and demand patterns, is very high in the future, as described in Part 2.
- And finally, changes in the power system affect the whole of society and potentially have major consequences for many players, as we have painfully realised during the recent energy crisis.

In the following, these complex relationships, possible consequences and uncertainties are described and assessed as far as possible within the framework of the committee.

15.1 Measures that reduce the utilisation of exchange capacity with other countries

In the energy debate, a number of measures have been proposed[50] to reduce the use of exchange capacity with other countries. The purpose of these proposals has mainly been to limit the price impact from other countries, and thus provide lower power prices for consumers in Norway.

Reduced exchange can either involve reducing the use of the interconnectors in both directions, i.e. both exports and imports, or reducing exports only. A reduction in exports means that the power is reserved for the Norwegian market to a greater extent than otherwise. This reduces the need for imports accordingly, but import capacity is maintained. If Norway unilaterally reduces exports, there is a risk that the counterparties on the cable links in question will introduce similar restrictions, so that trade is in practice limited in both directions. Whether the restrictions apply in one or both directions is important for the consequences of the measure.

The scope of the restrictions will depend, among other things, on which connections are covered, for example all, only submarine cables, or only to certain countries, and how much the exchange is reduced on the connections in question and how long the restrictions last.

We do not analyse the effects of cutting submarine cables or all international connections in this chapter; this is discussed in chapter 12.3.

[50] The committee has received assessments of this from Rune Valle (including SKM Market Predictor AS and Elkem ASA), Renewable Norway, Hafslund Eco, Statkraft and others.

15.1.1 Potential alternative designs

A reduction in power exchange can be achieved in many ways. The following is a brief description of various conceivable measures to reduce the export of power from Norway. We then look at the price impact of the various measures.

Each of the measures is assessed as an emergency measure or as a permanent measure:

- If the measure is implemented as a *crisis measure*, it means that the measure is implemented "overnight" without the participants in the power system being notified in advance. After the crisis is over, the measure lapses. We then assess the effects during the crisis period alone.
- If the measure is introduced as a *permanent measure according to fixed criteria (time of year, reservoir filling, etc.),* this means that the stakeholders are aware in advance that the measure will be introduced for a period of time and what conditions will trigger the measure. This is equivalent to knowing that the "crisis measure" will be introduced every year.
- If the measure is implemented as a *permanent measure for the entire year*, it means that we will reduce our exchange capacity with other countries in the years ahead, cf. chapter 12, but is also briefly discussed in this chapter.

In the following, we consider seasonal exchange capacity, throttling export capacity when reservoir levels are low and throttling exchange capacity when prices are high. We then go through measures that permanently change the transmission capacity abroad and finally a separate bidding area around the landing points for the international interconnectors.

Seasonally adjusted exchange capacity

Transmission capacity abroad can be reduced for a specific period of time during the year. Consumption and prices are normally highest in Norway during the winter, and it is natural to imagine that the measure covers this period. A practical design of the measure could be an order to Statnett, as owner and licence holder for the international cables, to reduce the transmission capacity abroad for the relevant winter season.

When introducing the measure, a decision must be made on how much the exchange capacity is to be reduced, whether it should apply to transmission over one, several or all connections and exactly what time period the measure applies to.

Throttle export capacity when reservoir levels are low

Throttling export capacity in the event of low reservoir levels means reducing the capacity of the transmission links given a certain level of reservoir levels. The purpose is to strengthen security of supply, but in the following we are mostly concerned with understanding the price effects of the measure.

When introducing the measure, a decision must be made on the reservoir filling level that triggers the measure and how long the measure will last, i.e. when the reservoir filling level is sufficient for the measure to be cancelled. Furthermore, it must be clarified whether the rule should apply to the entire country or be customised to each individual bidding area. A further question is whether all reservoirs should be covered or, for example, only multi-year reservoirs or reservoirs above a certain size.

Throttle exchange capacity at high prices

The measure involves reducing the flow over the transmission links when prices exceed a certain level.

Here, too, there are many factors that must be considered when introducing the measure. Firstly, it must be determined which price level triggers the measure, and whether it is the prices in one or more bidding areas that are decisive. This also includes assessing how long the prices should have been at a certain level, should it be the last 24 hours, week or month that is used as a basis? Furthermore, it must be considered how much the exchange capacity should be reduced, as with seasonally adjusted exchange capacity.

15.1.2 What are the effects of these measures on prices and security of supply?

Overall, we consider the effects of reduced exchange capacity to result in lower prices in normal years. In wet years, the risk of water spillage and flooding increases.

In dry years, we are dependent on imports. The measures may then lead to higher prices and a greater possibility that security of supply will be challenged if neighbouring countries introduce similar restrictions. How neighbouring countries react is an open question. Experience shows that Norway's neighbouring countries are concerned about treating each other with reciprocity and that any unilateral restrictions are proportionate by minimising negative effects on neighbouring countries and allowing neighbouring countries the same opportunities.[51] RME also points out that reduced trading capacity for reasons other than system operation (i.e. mainly the stability of the power grid) would be contrary to the main rule in the EEA Agreement, relevant energy regulations and the trade agreement with the UK (RME 2022). See also chapter 15.3 for a more detailed assessment of the legal framework.

The size of the effects depends on the extent of the restrictions on exports and imports. The greater the reduction in exchange capacity, the greater all the above-mentioned effects will be. It is also the case that crisis measures have smaller effects than permanent measures. A crucial point in understanding the effect on prices and security of supply is how the measure affects trade patterns.

We currently have a power surplus in normal years. In a situation where we have a power deficit, we will be more vulnerable in a dry year to very high prices and, in the worst case scenario**,** a challenging situation for security of supply if the counterparty also introduces similar restrictions aimed at us.

Effects on price and security of supply when introducing the measures as "crisis measures"
Let us assume that the measure is introduced "overnight", i.e. that the scheme is introduced without prior notice and is not intended as a permanent scheme that runs for several years. In this case, hydropower producers will not have the opportunity to change their reservoir utilisation before the measure is implemented.

The hydropower producers' reservoir filling level at the introduction of the measure will depend on whether it has been a dry, normal or wet year and other market conditions. Regardless of the degree of reservoir filling the producers have, there will be fewer opportunities to trade with foreign countries after the measure has been implemented.

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[51] In autumn 2021, Statnett changed its practice for calculating exchange capacity with Sweden by no longer taking into account so-called system protection on the Norwegian side. System protection are settings in the grid that contribute to increased trading capacity in the grid while at the same time entailing a certain risk in the operation of the grid. Since the Swedes' approach to capacity calculation did not allow for the same operational risk that Statnett took into account, Statnett believed this resulted in an imbalance that limited Norway's import opportunities more than its export opportunities. Later, the co-operation improved. Svenska Kraftnät did more to optimise power flows. Close operational cooperation between the two system operators significantly improved capacity between countries, and towards the end of 2022, Statnett returned to its previous practice of taking system protection into account (Statnett 2021, Statnett 2022).

- In *a normal year,* we can assume that there is sufficient storage capacity to cover domestic consumption during the season. Since there are fewer trading opportunities, there will be less price erosion from neighbouring countries. In the current situation, where gas power on the continent sets the price during the winter for many hours, price contagion from reduced exports will result in lower prices.
- In *a wet year,* reservoir levels will be higher than normal. Prices in Norway will initially be low, even if prices abroad are higher. The connections from Norway to other countries will then be utilised to a greater extent for export. A restriction on exports then entails a risk of water spillage and, in the worst case, an increased risk of flooding (and even lower prices in Norway).
- If the measure is introduced overnight *in a dry year, the* price effects will be different. A dry year means that reservoir levels are likely to be lower than normal when the measure is announced. We can then envisage two alternative situations, depending on whether prices abroad are lower or higher than in Norway:
  - If prices abroad are highest, the starting point will be that Norway exports before the restriction is introduced. In isolation, the measure will then contribute to reduced exports and lower prices in Norway.
  - However, if prices abroad are relatively low, the starting point will be that Norway imports. Export restrictions alone will not affect the price in Norway - there are no exports to restrict.
  - In dry years, we generally benefit greatly from importing power from our neighbouring countries. However, the question is whether prices in neighbouring countries are even higher or lower than in Norway, and how neighbouring countries react to unilateral restrictions from Norway. If limitations in exchange capacity also result in reduced imports from abroad, the measure will lead to greater scarcity and thus higher prices. A lack of import opportunities can then challenge security of supply and, in the worst case, lead to rationing.

If the aim is to reduce prices, it is therefore primarily in a normal year that we can be most confident that export restrictions will result in lower prices than we would otherwise have had in Norway. In dry years, when reservoir levels are lower than normal, we are dependent on other countries not triggering countermeasures so that imports are restricted in order for prices to be lower. If import restrictions are triggered, prices may be higher and security of supply weaker than without the restrictions. In wet years, price flu has far less of an impact, and the introduction of a measure results in a waste of resources and an increased risk of flooding.

This assessment applies in the current situation. Then the question is whether the consequences of reducing the exchange capacity to other countries will be different if we look at the scenarios developed in chapter 12.2. In two of the scenarios, we assume that we have such a large power deficit that we have higher prices than abroad over the year. In this case, we have net imports, and an export restriction alone will not result in price effects. If, on the other hand, the counterparty introduces an import restriction, import capacity will contribute to higher prices in Norway.

Effects on price and security of supply when introducing the measures as permanent
Let us then look at the effects if one of the measures is introduced permanently, and with clear conditions for when the measure is triggered. This results in a situation where hydropower producers are aware that transmission capacity will or may be reduced and can adjust reservoir utilisation accordingly.

Hydropower producers continuously assess and adjust the value of producing today, or the value of producing in the future, cf. chapter 7. In these assessments, the hydropower producers look at developments in gas and CO_2 prices, exchange capacity, reservoir filling and how much snow there is in the mountains. They also assess what demand might be. If producers know in advance that export restrictions will be introduced, they will take this into account when assessing the value of postponing production rather than producing 'now'. This means that the reservoirs are utilised differently and production takes place at a different time than without measures.

Here we first look at *"seasonal exchange capacity"*.

In this situation, hydropower producers know that the exchange capacity will be reduced for a certain period each year. This applies regardless of the inflow during the year. We imagine that the export restriction is set as a restriction that reduces the export capacity of the transmission links for all hours in the period. This could mean, for example, that a capacity of 1,000 MW in both directions is reduced to 800 MW for export, while import capacity is basically maintained.

If export capacity is reduced slightly throughout the winter season, hydropower producers will "lose" some of their exports during the high price periods. This means that the expected value of storing water for the winter will fall, and thus that winter prices will be lower. However, it is not certain that net exports will be reduced only in the period to which the export restriction applies. This depends on the trading pattern between countries, as different quantities are traded at different times. It is conceivable that hydropower producers may instead increase production at other times of the season, for example during hours when we would otherwise have imported, but at lower prices than they would otherwise have achieved. This means that security of supply may not be strengthened, as reservoirs may be reduced just as much as without the measure.

However, hydropower production may be lower in winter than without the restriction. In that case, production will be higher in another period of the year, before and/or after the restriction is cancelled. In that case, more will be exported for a few more hours where imports were previously made at relatively high prices, resulting in lower prices because the Norwegian water value must then be reduced to ensure that the power flows out of the country.

Overall, the export restriction will therefore result in a lower average price over the year.

But what happens if an import restriction is also introduced during the same period? In isolation, reduced import opportunities will lead to higher prices. As long as there is sufficient reservoir filling, the net effect will probably still be somewhat lower winter prices. If we are in a dry year, reduced import opportunities can lead to shortages and higher prices and, in the worst case, be dramatic for security of supply.

In the above assessment, we have assumed that Norway has a power surplus in normal years. In two of the scenarios in chapter 12, we have assumed that we have a power deficit. How will this change the effects of the measure? If we have a power deficit, we are more dependent on imports. The effects of the measure will be as above, but we will be in an even more vulnerable situation if our counterparties introduce import restrictions, especially in dry years.

The measure *"to manage export capacity when reservoirs are low"* will have a similar effect.

Hydropower producers will now realise that there is a risk that export capacity may be reduced if reservoir levels are too low.

We envisage a situation during the autumn where reservoir levels appear to be approaching the level that triggers an export restriction. This increases the likelihood that winter prices will be lower. Hydropower producers will then have an incentive to produce more in the autumn, which will result in lower prices in the autumn. This increases the likelihood of the export restriction being triggered, contrary to the intention of strengthening security of supply. In the winter season and throughout the year, however, the price effects will probably correspond to those described under seasonal exchange capacity.

Implementing this measure introduces further uncertainty into the players' water utilisation. It is conceivable that it may give some hydropower producers a weaker incentive to export early. If so, this would reduce the effect discussed above, but it is unclear whether, and if so, how much of an effect this could have.

The measure *"managing exchange capacity at high prices"* will have similar, but also some other effects.

There are many factors that determine prices, the most important of which are our own power balance, transmission capacity and the price abroad. In the short term, our own power balance depends on our inflow, i.e. whether we are in a dry, normal or wet year. In all these inflow situations, the foreign price could conceivably be so high that it triggers export and import restrictions when the measure is introduced.

Hydropower producers are closely monitoring developments abroad and will factor this into their calculations. In the same way as in the previous measure, they will know that export capacity may be limited if prices become sufficiently high. If, during the autumn, hydropower producers see that winter prices are so high that they trigger the export restriction and the water value is reduced in the future, they will produce more in the autumn than they would otherwise have done. This results in lower prices in the autumn. This also increases the likelihood that the measure will be triggered, as the reservoirs are at a lower level than usual at the start of winter.

However, in the winter season and beyond, the price effects will probably correspond to those described under seasonal exchange capacity.

If there are no prospects for exports anyway because it is a dry year, the effect may be less. Normally, prices will be highest in dry years, and then, as previously mentioned, it can be a challenge with both higher prices and, in the worst case, security of supply if the counterparty introduces similar restrictions aimed at us.

In chapter 12, we have highlighted that the power systems around us are undergoing major changes. This means that periods of high prices may occur at different times than previously, even in normal and wet years. This increases the risk of flooding and water spillage if export restrictions are introduced.

15.1.3 What effects will the measures have on other parts of the power system?

With lower average prices, the incentives to invest in new power generation are weakened. This also means that consumers have weaker incentives to invest in energy efficiency.

Trade with other countries is affected. In the event of a temporary reduction, there will be a time shift in exports, less in the period covered by a reduced exchange capacity and more in other parts of the year. Depending on the relationship between the power price abroad and the power price in Norway, total net exports over the year may be roughly unchanged, but producers will probably have a somewhat lower export value, and the value of hydropower as a provider of flexibility will be weakened when less is exported.

Limiting exports also reduces the possibility of short-term power exchange, which is done to even out variations in wind and power peaks. Norway often has high imports and exports at the same time (Statnett 2022), typically with imports from the UK and exports to Germany and Denmark in parallel.

This has little impact on the degree of capacity utilisation in Norway, but provides good overall resource utilisation and large trading revenues.

The Menon/AFRY analysis points out that the consequences of a permanent export restriction[52] affect the socio-economic indicators in the power market. The effects of these temporary measures will be similar, but smaller in magnitude: The producer surplus will be smaller, the consumer surplus will be larger and the congestion revenues will be smaller. If the measure involves a temporary export restriction for part of the year, some of the effect of an export restriction will probably be offset by changes in the hydropower producers' reservoir utilisation over the year. The overall distributional consequences are therefore more uncertain, but it is likely that producers will lose something and consumers will be better off. When producers receive less income, this also means that the owners of the hydropower companies receive less dividend and the state and municipalities receive less income.

Lower prices and weaker incentives lead to less development of renewable energy. However, the lower prices may mean that Norway will have more competitive prices and that more people will want to locate here or expand existing operations. If so, this will contribute to increased demand and higher prices. It is therefore difficult to say anything about the consequences of the measure for nature intervention and greenhouse gas emissions, as it depends on the time period used as a basis.

As with crisis measures, export restrictions entail the risk of countermeasures from neighbouring countries. Such countermeasures can affect security of supply, resulting in higher prices and a more strained situation in dry years.

Measures that permanently change the transmission capacity abroad

In the years to come, we will be faced with new decisions to reduce or increase exchange capacity abroad. In a few years' time, the agreement on some of the transmission links to Denmark will expire, raising the question of whether or not they should be renewed. It has also been decided by the Norwegian authorities to facilitate areas that can enable the development of 30 GW of offshore wind power by 2040. Such a development will add about as much new power to the Norwegian power system as we produce in a normal year today. This raises the question of whether it makes sense to increase transmission capacity abroad.

The Commission has not analysed these cases separately, but points out below some of the effects of permanent changes in transmission capacity abroad, whether it is reduced or increased.

Changes in transmission capacity can take place in several ways. We will restrict ourselves here to discussing the direction in which the effects will go as a result of either a reduction or an increase in transmission capacity. In this assessment, we therefore assume that transmission capacity is reduced in both directions, thereby changing both export and import capacity. The magnitude of the effects depends on the size of the reduction or increase, and this must be analysed in each specific case. For further assessments of foreign trade, see chapter 7.1 and chapter 12.3.

What are the effects of the measures on prices and security of supply?

For hydropower producers, changes in transmission capacity have an impact on the water value. If transmission capacity is increased in a situation with higher prices abroad, the water value will be higher. This means that prices in Norway increase, but also results in more stable prices. Similarly, a

[52] Note that this analysis was based on the assumption that import capacity was left untouched. If neighbouring countries introduce similar restrictions against Norway, the price effect will be weaker because we will miss out on cheap imports from Europe with high production of solar and wind power during periods of low inflow in Norway. Overall, we will have a slightly lower expected price, but probably slightly higher flood losses and slightly more rationing.

reduction in transmission capacity will reduce the ability to export during hours of high prices abroad, thereby contributing to lower prices in Norway. However, there will be greater variation in prices as a result of more hours with zero prices and more hours with very high prices.

Both situations are illustrated in the figure below, which also highlights the consequences of a dry or wet year in Norway.

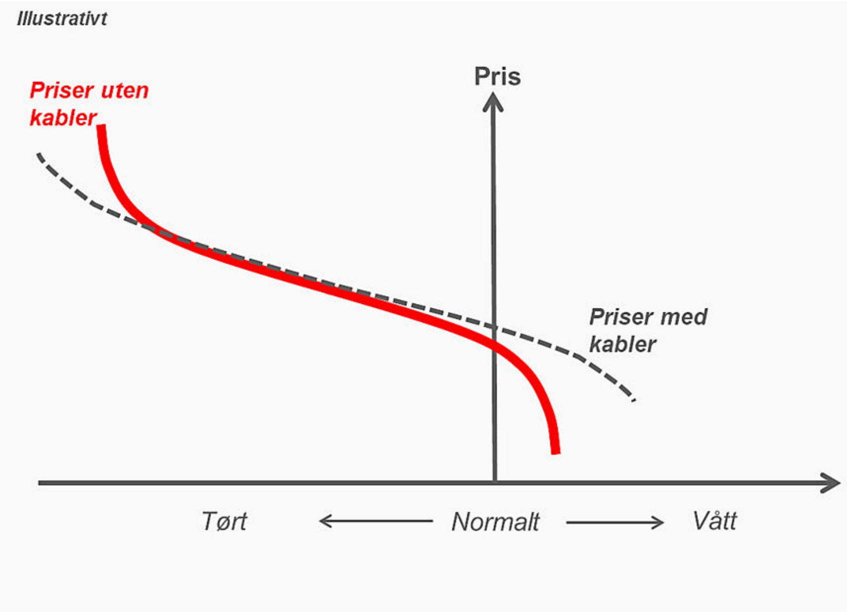

Figure 15- 1 The probability distribution for prices is different with and without interconnectors

The figure shows that reducing transmission capacity will result in higher prices in dry years and lower prices in wet years. By increasing transmission capacity, we have a greater opportunity to import in dry years and to export more in wet years, which helps to stabilise prices.

In a situation where there is such a large power deficit that prices abroad are lower than in Norway, as outlined in the scenarios in chapter 12, the price effects can have the opposite effect. In this case, a reduction in transmission capacity will result in higher prices in Norway if we have to import more, while an increase in transmission capacity will result in lower prices in Norway. These effects are described in more detail in chapter 7.1.

The figure also illustrates that security of supply is strengthened by having greater transmission capacity to other countries. At the same time, it makes us more vulnerable to developments in our neighbouring countries. To reduce the vulnerability of individual countries, it makes sense to have transmission capacity to several countries.

As mentioned, the magnitude of these effects depends on the size of the reduction or increase in transmission capacity. This also applies to the issue of security of supply.

What effects will the measures have on other parts of the power system?
In the current situation, a reduction in transmission capacity abroad results in lower average prices. There may be greater price variations at an annual level, but less price variations from hour to hour. This weakens the incentives to invest in new power generation and short-term flexibility on the demand side, but strengthens the incentives to invest in more power.

An increase in transmission capacity will naturally entail investments in cables and other necessary equipment. It will also be necessary to strengthen the infrastructure on land to be able to handle the changed power flow. This would result in greater intervention in nature.

Trade to other countries will be affected, but how will depend on how the measure is implemented. If it is implemented as a sum restriction on all transmission links, the trade pattern between countries will probably be maintained, while if a transmission link to a country disappears, there will naturally be less trade to that country. As long as the change in transmission capacity is not as great as discussed in chapter 12, net exports to other countries will remain the same, but at lower prices than before.

The socio-economic effects of reduced transmission capacity resulting in lower prices are also that the producer surplus is reduced, consumer surplus is higher and congestion revenues are reduced. The sum of these factors points in the direction of a reduced overall socio-economic surplus in Norway.

Increasing transmission capacity will have the opposite effect as long as we have a power surplus and lower prices than abroad to begin with.

However, these effects are reversed if we reduce transmission capacity in a situation with a power deficit in Norway. In this case, reduced transmission capacity will lead to higher prices, resulting in a higher producer surplus and lower consumer surplus. In this case, there will also be less congestion revenue. As consumption is greater than production, this points in the direction of an overall reduced socio-economic surplus in Norway.

It should be emphasised that we have described the first-order effects of changing the transmission capacity abroad. Over time, many of these effects will be cancelled out as a result of other changes in the power system. For example, lower prices as a result of reduced transmission capacity may lead to increased consumption as new industry establishes itself in Norway that would not otherwise have done so. New industry can have a positive impact on employment and value creation, but can also lead to encroachment on the countryside. The increased demand for power can help to mitigate the price effects for other consumers.

Dedicated bidding area around the landing points for international connections

Many have suggested establishing a separate bidding zone for exchange. The idea is that you can then get different prices on the cable and in the bidding zone and thus get lower prices in the rest of Norway. In practical terms, this can be done as in the sketch below. An additional bidding zone is established between the relevant Norwegian bidding zone and the foreign bidding zone, illustrated by the red circle. The capacity of the connection itself is assumed to be unchanged, but a decision must be made as to what capacity is determined between the Norwegian bidding zone and the new area, as well as between the new bidding zone and abroad.

For the latter, it must be assumed that the capacity is calculated in the same way as before, so that the capacity of the interconnector depends on internal power flow in neighbouring zones (see also the fact box on capacity calculation in chapter 5.6). Seen from abroad, the new zone is just another Norwegian bidding zone and the arrangement will not in itself affect internal power flows abroad. As the new bidding zone is unlikely to contain production or consumption (which must be almost the whole point of the zone), there will also be no internal power flow in the zone that can affect the capacity calculation for the interconnector itself.

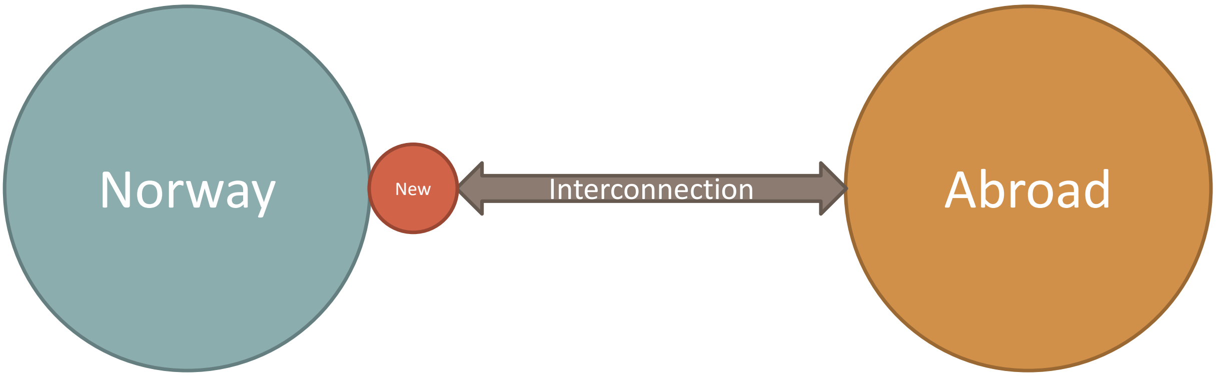

Figure 15- 2 Illustration of separate bidding area for international trade

The capacity between the Norwegian bidding zone and the new zone will, as before, also depend on internal power flows in Norway and power flows in the new zone. However, since the area is unlikely to have any internal power flows that could affect the capacity between it and the Norwegian bidding zone, the capacity is also calculated in the same way as without the new bidding zone.

The establishment of a new bidding zone without consumption and production, which will be located between a Norwegian and a foreign bidding zone, will thus not be able to result in any other exchange capacity that is included in the price formation.

As explained in chapter 6.2 price formation in the spot market takes place by participants submitting purchase and sales bids according to the production or consumption they wish to serve in the bidding zone. Everything that is offered for sale in a bidding zone must either be purchased or produced in the zone. Since no one has power generation or power consumption in the new zone, it is reasonable to assume that no one will submit buy or sell bids for this zone. In the price calculation, the zone will then become a pure transit zone. Any production in excess of consumption in the Norwegian bidding zone will thus be used directly in the price calculation in the foreign zone (or vice versa). Alternatively, if one imagines that some submitted purchase bids and others submitted sales bids for the new zone, the equilibrium must be such that total purchases are equal to total sales in the zone - the opposite requires that there is production or consumption in the zone. In such a situation, the new zone will also be a pure transit zone. Thus, the price in both the foreign and the Norwegian bidding zone will be the same as without the new zone. The price in the new zone will be equal to the price in either the Norwegian or the foreign bidding zone, and in any case has no significance for Norwegian buyers or sellers of power.

The explanation is simply that if the physical realities of the power grid do not change, the measure will not have any effect on the price in Norway. The creation of the bidding zone means that the bottleneck is simply moved from the border between abroad and Norway to internally between two bidding zones in Norway. As there is no restriction on the transmission capacity between the two bidding zones, the prices will be the same.

For the measure to have an impact on prices, it must be designed so that the capacity into the bidding zone is set lower than the capacity of the transmission link.

When introducing a measure with a capacity restriction, many of the same assessments must be made as for the other measures in this group related to the duration and scope of the restriction.

15.1.4 What barriers exist to implementing such measures?

There are many issues of a purely practical nature that need to be clarified in connection with the introduction of these measures, which makes it difficult to assess the effectiveness of the measures.

Many of these are mentioned in the description of the measures and concern, for example, setting precise conditions and frameworks for the measures. Separate investigations will be required if it is decided to proceed with these measures.

The legal framework is particularly important when considering the introduction of measures that reduce exchanges with other countries. The legal framework is explained in chapter 15.3

15.2 Measures aimed at changes in reservoir utilisation

Chapter 7 discusses the relationship between reservoir utilisation and pricing in the market. In the debate surrounding the electricity price increase, reservoir management as a measure to reduce the price level has been discussed. This chapter discusses the effects of changes in the framework conditions for reservoir management on the price level.

Management of water reservoirs is also being discussed as a measure to increase security of supply. In a consultation note, the MPE points out that some claim that Norway has left too much of the responsibility for security of supply to the market, and that hydropower producers do not have a sufficiently clear responsibility to contribute to security of supply for energy[53] . Several have also advocated limiting hydropower producers' freedom of action over water reservoirs beyond what follows from licence provisions on the highest and lowest regulated water levels. In contrast to the measures discussed in chapter 15.1, we discuss here measures that directly interfere with this freedom of action, i.e. water utilisation. The commission does not make a separate assessment of security of supply in the Norwegian power system, but since changes in reservoir allocation are also relevant in the context of security of supply, we also look here at how proposed measures for reservoir allocation in the context of security of supply affect the price level.

15.2.1 Potential alternative designs

In the following, we will provide a brief description of various measures to change reservoir utilisation. The purpose of the measures is to strengthen security of supply, but the measures will also have price effects. It is the possible price effects that are our main concern, but in the same way as in chapter 15.1 we also discuss the consequences for the power system and society in general.

Absolute magazine restrictions

The proposal involves setting a minimum requirement for the fill level in Norwegian hydropower reservoirs. The minimum requirement for the filling level in the reservoirs must be higher than the filling level hydropower producers would otherwise have had without the restrictions.

An absolute reservoir restriction will be a requirement imposed on hydropower producers. The requirement is set for the filling level at a given time in the spring before the bottling season is over, and when the reserve can be utilised or not. As long as the requirement is met, the hydropower producers can use the water as they see fit within their licences (but the requirement may mean that they cannot go all the way down to the lowest regulated water level that follows from the licence conditions in the period to which the restriction applies). This means that hydropower producers must plan their utilisation so that the restrictions are complied with in all weather years.

The requirement can either be set for each individual reservoir or for a larger group of reservoirs (as an average requirement). The Norwegian power system consists of over 1,000 reservoirs with different dynamics in filling and emptying. Some reservoirs are set up to handle variations over the day or week, while others are designed to handle seasonal variations. Consequently, it is uncertain how one would proceed in practice to set requirements for each individual reservoir and then

[53] horingsnotat-om-endringer-i-vassdragsreguleringsloven-og-energiloven-styringsmekanisme-for-for-forsyningssikkerhet-l1477838.pdf (regjeringen.no)

administer a regulatory framework around this. It is therefore natural to think of this as a requirement for all reservoirs as a whole, within a limited area (for example a bidding area, or part of a bidding area), or possibly only for reservoirs above a certain size in the selected area.

As such an arrangement would interfere with existing licence conditions and manoeuvring regulations, the legal framework for a change will need to be assessed in more detail. The committee will limit itself to pointing this out here.

Requirements for reservoir filling in combination with quotas
The measure involves setting a minimum requirement for the filling level in reservoirs in an area and combining this with a system of tradable quotas to provide a more efficient distribution of reservoir restrictions between operators (RME 2022).

Such a quota system does not exist today, and requires the development of decision support tools that can help organisations to determine the value of the quotas. It is possible to implement the tools in existing systems (Mo, Wolfgang og Naversen, Vurdering av kraftsituasjonen 2021-2022 2023). It also requires the development of a trading platform for trading quotas between producers. One challenge in this context is that trading must not lead to producers gaining insight into each other's reservoir utilisation. Otherwise, trading will facilitate market manipulation and coordinated behaviour in the market.

The other effects of the measure will be the same as for the measure to impose absolute reservoir restrictions. What this variant can contribute is related to the implementation of the measure. It reduces the challenge of setting minimum requirements for individual reservoirs and, through trade, facilitates that the minimum requirement can be distributed more efficiently between individual reservoirs. The measure can thus lead to lower socio-economic costs. In particular, the risk of flood losses can be reduced.

Tax on production when reservoir filling is low
An alternative way to influence reservoir utilisation and steer the reservoir filling rate in the desired direction is a temporary tax on production (RME 2022).

By imposing a tax on the regulatable production in an area, hydropower producers will have a higher marginal cost and shift production to a later period (with higher reservoir levels and/or lower taxes).

One challenge with this proposal is to determine how to set a fee that provides a desired level of filling in the reservoirs. RME points out that a fee that is too high will result in less optimal utilisation of the water and increased costs due to potential flood losses. A fee that is too low will not produce the desired result for reservoir filling.

Another challenge is that more production is at risk when it is not subject to a levy than would otherwise be the case. This means that a lower reservoir filling level will be reached more quickly than without such a tax, which is precisely what is not desirable.

Variable magazine restrictions
An alternative approach could be to reduce the lowest regulated water level if the power situation is particularly tight, with very high prices and a high risk that available resources will not be sufficient to cover consumption until the snowmelt is expected to start. The idea would be to accept greater environmental costs (as tapping below the 'normal' lowest regulated water level (LRV) would entail) when the value of additional power generation is particularly high.

As with other measures aimed at reservoir management, the practical challenge will be to translate the idea into concrete regulations. How much should the lowest regulated water level be lowered?

Should there be the same reduction for all reservoirs, or only for selected ones? What should be the criteria for introducing and suspending the measure and returning to normal LRV? And is it practically possible to draw down below LRV?

15.2.2 What are the effects of the measures on prices and security of supply?

Overall, we consider the effects of the reservoir restrictions to result in a slightly higher average price throughout the year and somewhat greater price variations. A higher average price and greater price variations result in weaker competitiveness and more unpredictable prices. The extent of the effects depends on how strong the reservoir restrictions are introduced.

The price effects are smaller if an area restriction is set and this can be distributed to the various reservoirs according to what provides optimal utilisation, than if restrictions are placed on individual reservoirs. This can be achieved, for example, by setting requirements for reservoir filling in combination with quotas.

One possibility is to set requirements for the lowest filling level that is targeted at the end of the bottling season in combination with a quota system. Such a restriction would only be binding if there is low reservoir filling and the prospect of scarcity. There are some challenges related to timing, as the spring peak does not occur at the same time every year. It must be possible to use the water after this date, so it must be set slightly before the expected spring peak. Such an arrangement will put a shadow price on the fact that society has an assumed higher willingness to pay for security of supply than the market does. In dry winters, hydropower producers will hold back more water than before. This means higher imports and leads to higher prices throughout the winter. The scheme will lead to higher prices in dry winters as less will be exported and more imported.

Effects on price and security of supply when introducing the measures as "crisis measures"

The measures are designed to strengthen security of supply. This means that in a typical dry year, we want to ensure that we have enough water in the reservoirs to cover consumption through the winter. In normal and wet years, that's not a problem. If we're already in a critical situation with very low reservoir levels at the start of the bottling season, the measures won't help. By then it's too late. Producers won't get much more water in the reservoirs until the filling season starts after the winter. On the other hand, we then have plenty of time to import the power we need.

There is therefore little point in implementing these measures as crisis measures. The measures must be implemented in advance, so that hydropower producers can retain more water than they would otherwise have done if the measures are to have the desired effect.

Effects on price when introducing the measures as permanent

Let us therefore instead discuss the effects of the measures if the measures are introduced permanently, and with clear rules for what hydropower producers, or more precisely owners of the reservoirs, should relate to.

A reservoir restriction means that hydropower producers must plan production so that the restriction is met regardless of the weather. This means that hydropower producers must ensure that they have enough water in the reservoirs to meet the requirement, regardless of how the summer, autumn, winter and spring progress. This means that hydropower producers will save more water ahead of the winter season to ensure that the requirement is met. As a result, less is produced, net exports are reduced (imports increase) and the price of electricity will rise ahead of winter, compared to the current situation without such reservoir restrictions. On the other hand, prices will be lower than they would otherwise have been, especially when the end of the abstraction season is reached, because more water is saved.

The overall effect is that the average price will be slightly higher than otherwise. A report from SINTEF that has simulated the effects of reservoir restrictions points to marginally higher average prices and greater price variations (Mo, Wolfgang og Naversen, Vurdering av kraftsituasjonen 2021-2022 2023). This indicates that flood losses will increase slightly, while the risk of rationing will generally be somewhat lower. Simulations conducted by Menon and AFRY also show increased price variations, but point out that the price effects are more uncertain and situation-dependent (AFRY og Menon 2022).

A complicating factor is that although we generally divide the year into filling and draining seasons, the situation for each reservoir is very different. One thing is multi-year reservoirs, which typically take several years to fill if you start at the lowest regulated water level. But even 'ordinary' reservoirs are very different. In Western Norway, there are several reservoirs that are filled, drained and refilled several times during the course of a year. Other reservoirs have a completely different 'annual rhythm'.

If restrictions on reservoir utilisation are only imposed on some reservoirs, for example the largest ones, or if the restrictions are implemented differently to take into account the fact that spring and snowmelt occur at very different times in Norway, the effects will be more uncertain. Producers without restrictions will see higher prices in the autumn and lower prices in the winter as an invitation to increase their production and increase the risk that their reservoirs will be reduced to minimum production before the snowmelt starts. This will counteract the desired change and thus reduce the overall impact of such restrictions.

It is particularly in situations that arise due to events with low probability and major consequences that a minimum fill level requirement can help to strengthen security of supply and can have a major impact on price formation. SINTEF has made a calculation for the committee that looks at the consequences of almost all submarine cables[54] failing for a period of a few weeks. In a dry year with restrictions, reservoir levels will be higher than normal, resulting in lower (or less high) prices than would otherwise be the case.

15.2.3 What effects will the measures have on other parts of the power system?

With slightly higher average prices and greater price variations, the incentives to invest in new power generation, including power investments, are also slightly strengthened. This also means that the incentives are somewhat stronger for consumers to invest in energy efficiency measures and various flexibility solutions. For power suppliers, less stable prices will contribute to an increase in demand for price hedging instruments and fixed price contracts. More electricity customers will appreciate it if suppliers, by virtue of their expertise, are able to provide good advice to their customers. How much the incentives are strengthened depends on how much restrictions are placed on storage utilisation.

As the average prices are higher, it is natural to assume that the producers are better off, while consumers lose out. When producers are better off, government revenues will also increase, both through higher dividends in line with other owners of power producers, and as a result of increased tax revenues.

Trade with other countries will be affected by the measure, but exports will primarily be postponed in time. Net exports over time, i.e. over several years, may increase slightly to the extent that higher

[54] The example includes all cables between Norway and Denmark, Germany and the UK. The cable to the Netherlands is still in operation.

prices lead to lower electricity consumption, but an increase in flood losses will naturally reduce exports.

Higher average prices mean that the cost of electrification to reduce greenhouse gas emissions will be higher. This will also reduce the incentives to localise more industry in Norway. If the higher prices trigger more power generation, this will dampen the price effect in the long term. In that case, it will involve intervention in nature.

In its simulations, SINTEF (2023) shows that the restrictions result in a lower socio-economic surplus due to greater flood losses and reduced production. This means less efficient resource utilisation. This must be weighed up against any increased socio-economic value of enhanced security of supply , i.e. the loss of efficiency is the price of increased security of supply.

15.2.4 What barriers exist to implementing the initiative?

There are a number of practical barriers associated with designing requirements for reservoir restrictions and some options for reducing these (Statnett 2022). One of the barriers is determining how large the requirement should be and what is an acceptable risk for society. Great uncertainty about inflow and power consumption in the coming months and the possibilities for importing make these assessments particularly difficult.

Hydropower producers currently manage the reservoirs in accordance with licences under the Watercourse Regulation Act. The licence granted to the producers gives them the right to manoeuvre the reservoirs within a set minimum and maximum water level. These limits are subject to revision on specific statutory terms. It should only be pointed out here that the scope for introducing measures as discussed above must be considered in relation to both the current regulations and the licences granted.

See otherwise chapter 15.3 on the limits of the EEA Agreement for measures that may affect the possibility of export and import.

15.3 Legal framework for power exchange with other countries

Norway has been exchanging power with other countries since the 1960s. Norway currently has power lines and subsea cables to Sweden, Finland and Denmark, and to the Netherlands, Germany, the UK and Russia with a total exchange capacity of approximately 9,000 MW. According to the EU regulation on cross-border power trading, which is followed up by Statnett's licences to facilitate power exchange with other countries, the capacity on the international interconnectors must be made available to market participants.

The starting point in the EEA Agreement is that there shall be free movement of goods in the internal market, cf. Article 8 EEA. Electric power is defined as a product covered by the EEA Agreement. It further follows from Article 12 EEA that "quantitative restrictions on exports and all measures having equivalent effect" are prohibited between Member States. The concept of measures is interpreted broadly.

Consequently, the general rule of free movement of goods limits the State's ability to impose restrictions on foreign trade in electricity. A measure that directly reduces the export of power abroad is understood to be an export restriction that is contrary to the general rule in Article 12 EEA" (RME 2022).

However, the prohibition on export restrictions does not apply if a restriction is justified on grounds of public "order and security" and complies with the principle of proportionality, i.e. that the restriction is appropriate and necessary to achieve the objective. The European Court of Justice has held that security of supply can be such a consideration that can justify an exception to the prohibition, see e.g. case C-648/18 (Hidroelectrica judgement).

In its consultation paper on control mechanisms for security of supply[55] , the Ministry of Petroleum and Energy has stated that an order to Statnett to reduce transmission capacity may be a possible instrument in a power rationing situation:

> *"One instrument in a power rationing situation could be to require Statnett to stipulate lower transmission capacity on the interconnectors (export restrictions). This can be done before Norwegian businesses and households are required to reduce consumption. Whether export restrictions are a relevant instrument in power rationing and whether they should be used before other consumption is disconnected will depend on a specific assessment of the situation. In such a situation, one may also be dependent on imports." (p. 16)*

The same memo mentions intervention in the producers' utilisation of water reservoirs as a possible instrument:

> *"If it becomes necessary to introduce power rationing, the energy authorities will have the right to intervene in the producers' utilisation of water reservoirs, ...Such a decision will constitute a regulation of energy production, which will also have consequences for the amount of power exported from the country. The fact that the consequences of the measure apply to both the domestic and foreign power market indicates that the measure does not constitute any form of nationality-based discrimination. The use of such a measure will in any case also be well anchored in the consideration of safeguarding security of supply in a hypothetical shortage situation." (s 18)*

As stated, the EEA Agreement provides some room for manoeuvre for measures that may restrict the export of electricity, if it can be justified by legitimate reasons as mentioned. However, in the aforementioned Hidroelectria case (C-648/18), the ECJ clarified that it is not a legitimate interest to adopt such restrictions in order to protect national markets from price increases. The CJEU stated (paragraphs 42 and 43):

> *'42 However, as stated by the Advocate General in points 73 and 74 of his Opinion, the obligation to offer all the electricity available on the trading platforms managed by the sole designated operator for trading services on the national electricity market - as a measure intended to prevent direct exports from having a negative impact on the development of the price of electricity on the national market - goes beyond what is necessary to guarantee security of supply of electricity.*
>
> *43 A guarantee of security of electricity supply does not mean a guarantee of the supply of electricity at the best price. The purely economic and commercial considerations underlying the national legislation at issue in the main proceedings do not fall within the sphere of public security within the meaning of Article 36 TFEU or within the sphere of general interest capable of justifying quantitative restrictions on exports or measures having equivalent effect. If such*

[55] Consultation memorandum from the Ministry of Petroleum and Energy on 29 June 2023 on amendments to the Watercourse Regulation Act and the Energy Act on control mechanisms for security of supply.

considerations can justify a prohibition on the direct export of electricity, the very principle of the internal market is called into question.

Measures that may have consequences for the flow of electricity between Norway and other countries must also be assessed in light of the energy regulations incorporated in Annex IV to the EEA Agreement, including Directive 2009/72, Regulation 714/2009 and Regulation 713/2009, which facilitate the transmission of electricity between Norway and other EEA countries. It follows from Directive 2009/72 that market participants must be granted non-discriminatory access to the electricity grid, cf. Article 32, and that electricity must be traded on market terms.

If a measure is considered to entail an export restriction, an exception may nevertheless be made if it can be justified by so-called overriding reasons in the public interest, and provided that the measure does not discriminate against nationality (Article 13 of the EEA Agreement). The use of these exceptions also presupposes that the measure is justified by an objective and non-economic consideration and that it complies with the proportionality principle, i.e. that it is suitable for achieving the objective being pursued and does not go beyond what is necessary. It is difficult to see that a unilateral export restriction on power for reasons of price development at national level can be justified by this exception rule, cf. also the European Court of Justice's statement in case C-648/18 on what can be legitimate reasons for exceptions.

In this context, it should also be mentioned that the Free Trade Agreement between the EFTA/EEA countries and the UK contains provisions on trade in goods, including electricity, with general prohibitions on import and export restrictions. The agreement allows for temporary export restrictions to prevent critical shortages of goods that are essential to the exporter. The agreement between Norway and the UK on cross-border trade in electricity and cooperation on transmission links, which was signed in September 2021, will, among other things, ensure that both parties facilitate maximum available capacity on the NSL connection. Capacity may be reduced in situations where security of supply is threatened due to power shortages or operational reliability, but there is no room to introduce restrictions in order to protect national markets from price developments.

The significance of the introduction of export restrictions cannot be assessed without also taking into account the impact it may have on the possibility of importing power. In its memo of 22 August 2022, RME writes the following about this:

"RME would like to emphasise the importance of any export restriction being designed in line with the EEA regulations and being well established in our neighbouring countries. If a possible Norwegian export restriction leads to countermeasures from other countries, the effect of the measure may be that our security of supply is weakened, rather than strengthened. Furthermore, it is important that any export restriction is designed so that it does not, under certain conditions, stimulate increased power production, which could also weaken security of supply in Norway. If, for example, it is expected that the measure will be introduced at a given time, for a specific fill level, or when other predetermined criteria are met, this may, in isolation, incentivise producers to produce more before a possible restriction occurs than they would normally do." (p. 3)

A restriction on the utilisation of the storage facilities has a direct impact on export opportunities. As mentioned above, the ECJ has expressly stated that it is not in line with the EEA Agreement to introduce export restrictions to protect national prices. Consequently, if measures related to the reservoirs as referred to in section 14.2 are to be considered, it must be possible to justify them on the grounds of security of supply and to show that the other conditions mentioned above are also fulfilled in order to be able to introduce the restriction, such as that there are no other alternative measures to ensure security of supply . In the Hidroelectrica case (Case C-648/18), the European Court of Justice stated the following about security of supply as a possible justification for an exemption:

> *"(36)However, the Court has held that the protection of security of energy supply may fall within the sphere of public security within the meaning of Article 36 TFEU (see, to that effect, judgment of 10 July 1984, Campus Oil and Others, 72/83, EU:C:1984:256, paragraph 34).*
>
> *(37)It is in the light of those circumstances that it must be assessed whether national legislation interpreted as requiring national electricity producers to offer all the electricity at their disposal on platforms managed by the sole designated operator for trading services on the national electricity market is proportionate to the legitimate aim pursued. In that regard, in order to ensure that such a system complies with the principle of proportionality, it must be ascertained not only that the means employed are suitable for achieving that objective, but also that they do not go beyond what is necessary to achieve it (judgment of 16 December 2008, Gysbrechts and Santurel Inter, C-205/07, EU:C:2008:730, paragraph 51).*
>
> *(38) As regards the ability of that legislation to achieve the objective of security of supply of electricity, it should be noted that the obligation imposed on national electricity producers to offer all the electricity at their disposal on trading platforms managed by the sole designated operator for trading services on the national electricity market, by prohibiting bilateral negotiations between those producers and their customers, does not, as such, appear unsuitable to ensure the objective of security of supply of electricity, since it is intended to ensure that the available electricity is geared more towards domestic consumption.*

In short, the EEA Agreement and the agreement with the UK set the legal framework for what restrictions Norway can place on the export of electricity via the interconnectors without violating the agreements entered into. The above-mentioned judgement from the European Court of Justice (C-648/18) clearly states that the consideration of national price developments is not a legitimate consideration that can justify restrictions on the export of electricity. For all types of measures that may be suitable for limiting the export of power and that are justified by the consideration of national prices for power, the starting point will therefore be that this cannot be implemented unless Norway's international obligations are renegotiated.

For measures that involve export restrictions, it will therefore have to be assessed whether they can be justified by any of the above-mentioned exemptions. As mentioned above, measures that affect the export opportunities for power may be permitted under the EEA rules if they can be justified on the grounds of security of supply, and provided that the other conditions are met. If measures can be justified on the basis of such considerations, it is conceivable that there is room to introduce them without contravening Norway's obligations under the EEA Agreement.

In this context, it may be recalled that it will probably not be contrary to the EEA Agreement if Norway limits current export opportunities by failing to renew existing cables. Nor would it be contrary to the agreement to refrain from establishing new international interconnectors (Hjelmeng 2023).

Within the given mandate, the committee has not had the opportunity to make a thorough assessment of the EEA Agreement's room for manoeuvre for export restrictions. If the authorities consider any of the measures discussed here that may involve export restrictions to be relevant, a thorough assessment must be made of whether this is possible within the framework of Norway's international obligations.

15.4 Measures targeting price in the wholesale market

In this section, we review a number of different measures that are more directly aimed at prices in the wholesale market. These include energy options, a power and energy guarantee scheme, a two-price scheme, a rule that a proportion of the power is sold outside spot on other contracts, a common price for consumption throughout the country (Norway price), a maximum price, measures to stimulate increased liquidity in the forward market, and measures to increase domestic transmission capacity beyond what Statnett is required to do in accordance with its purpose.

15.4.1 Energy options for consumption

Energy options for consumption can be organised so that Statnett buys rights from (major) electricity customers to reduce their consumption during the winter season. The idea is that it is better to agree on the terms for consumption reductions for some consumers on a voluntary basis if this can reduce the likelihood that a compulsory disconnection of several consumers will be necessary. The purpose is thus to reduce the likelihood of rationing by reducing consumption, not to affect prices, even though this may have an effect (Statnett 2022, Statnett 2014).

Such a programme has existed since the 2006/2007 season, when it was introduced as a so-called SAKS (Very Stressed Power Situations) measure (Statnett 2005). The last time Statnett purchased energy options was for Central Norway in the 2015/16 winter season.

The scheme is designed so that Statnett assesses the bids based on the benefit to the power system as a whole. There are several factors that come into play in addition to the cost of the option, including where the potential reduction in consumption is located and what volume may be required. The cost of purchasing the options is made up of two parts. The seller receives an option premium from Statnett when the option is purchased, and an exercise price if Statnett chooses to exercise the option. The option premium can be seen as a payment to certain electricity customers to prepare them to reduce consumption at specific agreed times and conditions. The measure partly solves the problem for larger end users when prices are high and they are considering reducing their consumption. Because they do not know how long prices may remain high, it may be more profitable to pay high prices and hope that the problem is short-lived than to reduce consumption as quickly as possible. By being able to sell energy options, the electricity customers in question can create security for Statnett that these customers will reduce their consumption if the situation requires it.

The programme has so far covered a small proportion of consumption, and was last used in Central Norway for the winter of 2015/2016. The purchase covered 89 MW with a total expected consumption in the period of 30 GWh. Statnett's cost was NOK 4.8 million. It is conceivable that the scheme could be designed to cover a much larger share of consumption. If a very large proportion of consumption is covered, the scheme will be characterised as a form of flexibility market, where consumers reduce their consumption in return for payment. This is discussed in more detail in Chapter 16.6.

What are the price effects of the measure?

If Statnett exercises the option, consumption is reduced earlier and/or to a greater extent than it would otherwise be reduced as a result of market prices. This means that other bids on the demand side become price-setting. The reduction in demand means that the price is reduced in the bidding area to which the scheme applies, unless other consumption comes in and replaces that which has expired.

The price effects of the measure depend on the proportion of consumption covered, how often such options can be triggered, and on price elasticities for consumption and production.

As the scheme has been designed, where only part of the consumption is covered and only triggered infrequently, the effects are considered to be marginal (SINTEF 2003). Energy options of a limited scope therefore do not have a major impact on price levels, price stability, predictability or how competitive the prices are. The measure is designed to reduce the risk of rationing, while having as little impact as possible on price formation or reservoir utilisation.

How does the measure affect the behaviour of actors along the value chain?
For consumers covered by the programme, the scheme means that they reduce their consumption at a price that is lower than the price at which they would otherwise disconnect.

If the scheme is made permanent, more comprehensive and with an increased probability of the options being triggered, the players' price expectations will be adjusted. This will primarily mean that operators' expectations of future price levels will be reduced and that it will become less profitable to save water. Hydropower producers with regulatory capacity may then, over time, change their reservoir utilisation so that some of the effect is reduced because the reservoirs are emptied earlier. The result will be that we will experience water shortages more often than otherwise.

What are the consequences of behavioural changes for the power system?
The measure is primarily aimed at strengthening security of supply. The price reduction as a result of the options being exercised may lead to a reduction in imports to the area. If so, this will reduce the effect of the measure on security of supply. The extent of this leakage depends on the situation in other areas.

As the effects on prices are marginal, other effects related to distributional effects, incentives for investments and energy efficiency and consequences for greenhouse gas emissions, nature encroachment, etc. are also considered to be marginal.

What barriers exist to implementing the initiative?
The measure exists in the sense that rules and procedures have been established for Statnett to purchase energy options from electricity customers in certain situations. The rules are organised in such a way that the use shall be limited and that implementation shall have as little price impact as possible.

With these premises (that the options are used to increase security of supply with the least possible price effect), the measure does not, as far as the Committee can judge, conflict with provisions of EEA law. If the arrangement were to be the opposite - maximising the price effect - the relationship to EEA law must be carefully assessed. In that case, it is also an open question whether the options would have had the desired effect, or 'only' resulted in increased exports.

15.4.2 Energy options for production

An energy option for production means that a buyer has ensured that a certain amount of power is available for a given period. In practice, this means buying a physical right to have hydropower producers withhold water corresponding to an agreed amount of energy in the event that the option needs to be exercised. The purpose is to reduce the likelihood of rationing.

A hydropower producer that enters into an option agreement in Norway will save more of the water before the option is exercised to ensure that the agreement can be honoured and the power can be delivered. In isolation, this means that the price before the option is exercised rises. The challenge is that other hydropower producers who do not have an option agreement will then produce more than they would otherwise have done. This means that the physical situation will not change overall, and the price effects will probably not materialise. There will be no more water to use in a shortage situation, which is the purpose of the measure.

To ensure that the measure leads to hydropower producers retaining more water overall than would otherwise have happened, it will therefore be necessary to buy options for large parts of what is needed to cover consumption in the period in question. Introducing energy options on such a scale is then equivalent to introducing reservoir restrictions (see chapter 15.2), or that Statnett in practice takes over water utilisation in Norway (Statnett 2005).

15.4.3 (Power and) energy guarantees - energy option without trigger function

Several manufacturers have proposed a mechanism that could be called an energy guarantee. This means that, through an auction solution, producers commit to guaranteeing that a certain volume of energy is available in the market at specific times, for example during the spring. The agreed volume may be offered to the market in the normal way, for example in the spot market and/or in the reserve markets, and at prices determined by the individual producer's water values. This does not guarantee that the volume will be utilised. It will depend on whether the producer values the volume higher than the market price.

A guarantee, as opposed to an option, means that the volumes will be released automatically when a certain date is reached, or within a specified number of weeks, for example during the spring break (before the snow melt really starts).

The hypothesis is that such a guarantee will coincide with the existing incentives to save water for the spring peak, and that the cost of such a guarantee will therefore be modest. The automatic release, and the fact that the producers themselves can use the reserve during the release period, helps to avoid unfavourable market adjustments as a result of the reserve.

What are the price effects of the measure?

The price effects of this measure depend primarily on the extent of the state's purchase of such guarantees. Although these are designed as guarantees, the guarantees have some common features with energy options for production (see chapter 15.4.2).

If the state purchases guarantees corresponding to a small proportion of the expected consumption for the period the state chooses to purchase, it is doubtful whether the measure will have any effect at all. The reason is that for the rest of the required production, producers will take the purchase of guarantees into account when calculating water values. We can think of this as the guarantee being linked to a separate 'reserve stock'. The market value for other players and reservoirs of holding a reserve will then be somewhat lower than if the reserve storage did not exist.

If the measure is to have any effect on prices or on total reservoir utilisation, the state must therefore purchase a guarantee for what it believes is necessary production in Norway throughout the winter. The question then is whether the purchase leads to more being stored for the winter as a whole than without the scheme. If this is the case, production in the preceding autumn will be lower than it would otherwise have been, and prices through the autumn will be higher than otherwise. For winter, the result will be the opposite - the expected price will be lower than without the measure. Since more is stored for the winter, the consequences of unpleasant surprises during the winter will be less, but the possibility of flood losses will be greater.

If the government buys less than the producers would have stored on their own, the question is whether the producers will still do what they thought was optimal, or whether they will trust that the government has made a correct assessment and thus produce more during the autumn than they would otherwise have done. If so, the measure will lead to lower prices in the autumn and the possibility of very high prices over the winter.

Another question is whether the time profile proposed by the state deviates from what the operators themselves would have planned. For example, what happens if the government buys more for February and less for March than the players' own plans? There is reason to believe that this would lead to relatively high prices in the producers' sales bids for February, with the result that actual production in February would be as it would otherwise have been. For March, it would then be the opposite - the sales bids would probably reflect that the savings in February were what the producers would have planned for anyway, and thus lead to the prices in March in reality not changing with the measure.

This highlights an important difference between a guarantee and an option. With a guarantee, producers who believe that the state has bought too little (too much) can price their water so high (low) that the actual production is what it would have been without guarantees. With an option, it is reasonable to believe that the state would have relied on its own judgements and asked for production in line with the options.

Overall, this means that it is highly uncertain whether energy guarantees will lead to different utilisation and thus different prices than we would have had without the guarantees. This depends on how the state determines the volume, and to what extent the producers set aside their own assessments in favour of the state's. The Committee is not in a position to assess how the producers individually or collectively will react to the state's potential demand for energy guarantees. If the state believes that it is better suited to control the withdrawal from all reservoirs, it is not obvious that it is necessary for the state to pay producers for the right to do so.

Introducing energy guarantees on such a scale is then equivalent to introducing reservoir restrictions (see chapter 15.2), or Statnett in practice taking over water utilisation in Norway (Statnett 2005)

How does the measure affect the behaviour of actors along the value chain?
Given the above analysis, it is difficult to see that the measure is likely to affect consumption, unless producers change their behaviour and the 'state's production plan' is realised.

What are the consequences of behavioural changes for the power system?
There are two outcomes that seem possible: either the result is that prices and security of supply are not affected, or alternatively, prices and probability of scarcity are dictated by the state's profile for the purchase of energy guarantees. In the latter case, the result can either be higher prices in the autumn and lower prices in the winter, or vice versa. Similarly, security of supply may be better or worse. In practice, this will depend on the state's ability to manage the reservoirs. Given the complexity of this, with just over 1,000 reservoirs with different characteristics, it is not obvious that the state's judgements will be better than those of the producers.

What barriers exist to implementing the initiative?
Designing a practical scheme for energy guarantees that leads with reasonable certainty to higher security of supply and/or lower or more stable prices appears to be a very complicated task that it is uncertain whether the state is in a position to solve. The state does not know any more about future power demand, future inflow and price conditions in neighbouring countries than the players do. If the state had such insight, it would be more obvious to share such information with both the supply and demand sides of the market.

Legally, the introduction of energy guarantees can be demanding, especially if the purpose is to influence national electricity prices (cf. section 14.1.4), but the barrier is lower if energy guarantees are designed with the aim of minimising the impact on prices and better control of security of supply.

15.4.4 Transmission capacity (domestic) beyond what is socio-economically profitable

During the energy crisis, we have seen some very large price differences between the price areas in southern Norway (NO1, NO2, NO5) and prices in northern Norway (NO3, NO4). Prices in southern Norway have been very high in some cases, while in northern Norway they have been normal and in some cases very low. In the summer of 2023, prices fell sharply in Eastern Norway and the Bergen area, while prices in NO2 have remained relatively high. The main reason is that Northern Norway and later Eastern Norway and parts of Western Norway have (had) a large power surplus and a bottleneck to the south due to high inflow in these areas. Because the transmission connection between north and south is far stronger in Sweden than in Norway, we have exported power from northern Norway to Sweden while importing power to southern Norway. See also chapter 7.1.

Increased domestic transmission capacity, both by physically building more grid, by better utilising existing grids and by using technology (phase shifters) to force electricity to flow domestically, will help to even out the price differences between regions.

Statnett already has a clearly formulated responsibility to expand the capacity in the transmission grid in line with what it finds socio-economically profitable. An important tool in this respect is Statnett's grid development plans. We therefore assume that Statnett's grid development plans contain those expansions that are basically socio-economically profitable (cf. Statnett SF's articles of association).

The question we have looked at in more detail is whether the transmission grid could be further reinforced, so that the price differences between the regions become even smaller, and possibly disappear almost completely. The assessment is based on a situation as in 2022 and 2023, with a significant power surplus in the north and a more balanced situation in the south. It must be emphasised that the comments below on north vs. south are related to this. Another time the resources are unevenly distributed, it may be the opposite, so that there are high prices in the north, while there is a significant surplus in the south. We do not attempt to draw conclusions about north vs. south based on these assessments.

What are the price effects of the measure?

Increased transmission capacity between the regions will help to equalise domestic prices. Consumption is far greater in the south than in the north, so it is natural to assume that in 2022, significantly greater domestic grid capacity would have led to somewhat lower prices in the south and much higher prices in the north. It is reasonable to assume that the same applies between NO2 (Kristiansand) and other bidding areas for the summer of 2023. The water volumes in NO1 and NO5 are primarily very large relative to the reservoir capacity in these bidding areas, not in relation to total consumption and reservoir capacity in NO1, NO2 and NO5 combined.

A report commissioned by the Ministry of Petroleum and Energy analysed the consequences for the power market of increasing transmission capacity between price areas in the current situation under different assumptions for gas prices (AFRY og Menon 2022). In this analysis, prices increase significantly in the north, and there is less water spillage. Prices in the south fall, but not nearly as much as they increase in the north.

How does the measure affect the behaviour of actors along the value chain?

For producers, increased transmission capacity means that reservoir utilisation will change. Producers in the north can deplete reservoirs further down in certain periods as a result of increased transmission capacity (AFRY og Menon 2022). In the south, greater transmission capacity has the opposite effect, but the effect is weaker. For producers in the north, the measure will result in increased incentives to invest in more power generation. For producers in the south, the measure will have the opposite effect, but because the price effects are much weaker, the investment incentives are less affected.

For consumers in the north in particular, higher prices will increase incentives for energy efficiency. For electricity suppliers, smaller differences between price areas can make it easier to offer fixed price agreements, which in turn can contribute to more predictable and stable prices for consumers.

What are the consequences of behavioural changes for the power system?
Increased transmission capacity between the regions, which is socio-economically profitable, leads to enhanced security of supply and more efficient utilisation of resources. If the bidding areas become larger, there is potential for greater volume and better liquidity in the financial markets.

If, on the other hand, we build far more infrastructure than is socio-economically profitable, this means that resources are utilised less efficiently overall. This weakens the price signals that are important for localising production and consumption where the need and opportunities are greatest**.** We can imagine two situations, one with price differences between the regions and another where prices are virtually the same.

In the first situation, a player who wants to build a factory where power is an important input factor will naturally look for the areas where prices are lowest. Establishing the factory increases demand in the area and the price increases. This reduces the price differences between areas. In the second situation, factors other than the price of electricity will play a role in localisation. This means that the factory may be located in a place where grid capacity is or could easily become scarce. This in turn triggers the development of more grid to reduce the price impact. Total costs in the system increase. The same happens where new production is located, but with the opposite effect.

Overall, this means that investments in infrastructure will be much higher than otherwise. This is charged to all customers via their network charges. In other words, consumers will have higher total costs**.**

Increased domestic transmission capacity may result in less power being sent from north to south via Sweden. This may mean less trade with Sweden in particular. Overall, this will mean that transmission losses in the grid will be reduced. Higher transmission capacity can potentially also reduce flood losses where, in the current situation, we have to limit production due to insufficient local demand and insufficient grid capacity.

What consequences will the changes in the power system have for society as a whole?
As prices rise in the north and fall in the south, the distributional effects between the players will differ between the regions. In the north, producers will have increased revenues, while consumers will have increased expenses. The opposite is the case in southern Norway, where producers will have somewhat lower revenues and consumers somewhat lower expenses.

The owners' changes in dividends will follow the same pattern, while it is more uncertain how the state's total income will be affected.

In the current situation, grid development is limited by the fact that transmission grids are very capital intensive. If Statnett builds more transmission capacity than it deems profitable for society, it is reasonable to assume that Statnett's costs will increase more than the current tariffs allow for, especially if energy consumption does not increase correspondingly. This indicates that the measure will result in higher grid tariffs than we would otherwise have had. The European regulations for tariffs are such that the cost increase must be borne by the electricity customers - not by the producers. The Norwegian practice is such that power-intensive industry has a significant discount on grid tariffs. In practice, the measure will therefore lead to higher grid tariffs, particularly for households and businesses, while the increase for power-intensive industry will be somewhat smaller.

Increased grid development as a result of this measure entails greater intervention in nature, without necessarily contributing to reduced greenhouse gas emissions as a result of increased electrification.

What barriers exist to implementing the initiative?
It takes a long time to build a new grid. The Power Grid Committee's report pointed out that it takes between 7 and 14 years to build a new main grid. Although efforts are being made to reduce lead times, this will never be a short-term measure to equalise domestic price differences.

15.4.5 Two-price: One price domestically and one price for power exchange

To obtain a separate price for trading over international connections, a separate auction solution can be created. Either as a joint auction for all international connections, as a separate auction for each connection, or a combination with a joint auction for some connections. A separate auction for each connection may have certain common features with the solution outlined with a separate bidding zone. Here, however, we will rationalise the analysis by assuming that separate auctions are held for one or more connections. Due to the market coupling with the rest of Europe, it is natural to think of this as first organising a separate auction for Norway and then including the international interconnectors in the European spot auction.

Trading on the UK National Grid (NSL) is currently carried out using a separate auction. This is due to the UK's withdrawal from the EU, and the fact that the EU would not accept the UK's participation in the joint European spot and intraday auctions. A separate solution therefore had to be established for electricity trade between Norway and the UK. An implicit auction (combined calculation of price and flow) with price coupling between bidding zones NO2 and the UK is carried out. This auction closes at 10.50 (Norwegian time) and the results are available shortly afterwards (Bjørndalen og Hagman 2019). Participants who have bought or sold in NO2 in the NSL auction can participate in the pan-European auction (SDAC) at 12:00. Potentially, an operator can buy in the NSL auction and sell the same volume in SDAC.

What are the price effects of the measure?
Over time, there is no reason to believe that the price formed in a separate auction will be systematically different from the power price in the relevant bidding zone in Norway. If there had been systematic differences in price at the auctions, market participants would have incentives to move the trading volume to the auction they expect to generate the highest return. In this way, market participants' behaviour will help to even out price differences over time.

In practical terms, we can imagine this being implemented as follows: At 10:00 each morning, a closed auction is run for Norway and then the SDAC auction (the day's spot market) is run at 12:00 as usual. The participants in Norway must presumably be able to choose which auction they participate in. As a starting point, let's assume that everyone aims to buy or sell what they have planned for the next 24 hours already in the Norwegian auction. What happens next depends on whether the participants as a whole envisage that Norway will import or whether Norway will export.

If Norway is in a clear import situation, buying interest will be greater than selling interest in the Norwegian auction. It is likely that this will result in a relatively high price in Norway. Some buyers will then not be able to buy what they had envisioned, and will therefore place bids in SDAC. The producers, on the other hand, may have sold what they had planned and may not place bids in SDAC at all.

If buyers are to buy what they need after the first auction, they must at least be prepared to pay more than the price in neighbouring countries. Whether they have to pay more in SDAC than they had to pay in the Norwegian auction, of course, we cannot know. The interesting thing is what happens the next day.

Let us first assume that the buyers realised that it was very expensive to buy what they lacked in SDAC. The next day, all else being equal, they will therefore signal somewhat stronger buying interest in the Norwegian auction. The producers, on the other hand, will realise that they could have received better payment on the first day if they had sold a little less in the Norwegian auction and sold a little more in SDAC. For day 2, we can therefore expect prices to be slightly higher in the Norwegian auction and slightly lower in SDAC.

This shift in buying and selling interest will continue until the prices in both auctions are approximately equal.

Alternatively, if Norway is in a clear export situation, the picture will be the opposite. However, the result will be the same - buying and selling interests will oscillate between auctions until the prices are equal. If it is uncertain whether we are in an import or export situation, this oscillation will take longer and there may be random differences. But over time, there is no reason to believe that systematic price differences will be achieved in the two auctions. If this were observed, buying and selling interest would move between the auctions.

One can imagine a variant of this, where Norwegian players were not allowed to participate in SDAC, but had to make all their trades in the Norwegian player. In this case, we would be dependent on 'someone' being commissioned to sell in the Norwegian auction when we import and buy when we export. Apart from the fact that it is difficult to imagine how someone could do this in practice, it is also difficult to see the economics of such an arrangement. Firstly, the operator would be bound to participate with the opposite sign in two auctions where the prices are not necessarily particularly well correlated, and secondly, the operator would alternately be responsible for net exports and net imports in a pattern that can be very difficult to predict. We therefore do not consider such a variant further - there is too much that is too unclear to make sense to analyse.

However, what is fairly clear is that a trading solution where participants can choose between a Norwegian and a European auction will not contribute to the goal of reducing price dispersion across international interconnectors, but could result in less efficient trading, partly because liquidity in the market is distributed between different auctions.

What barriers exist to implementing the initiative?

The administrative barriers to such a solution are probably not insurmountable - for example, it was not too demanding for Statnett to facilitate two auctions linked to NSL. As long as it is voluntary for the players to participate, it is not necessarily a huge burden for the players. On the other hand, such a solution will create considerable uncertainty for the players, especially the smaller ones. It is also difficult to imagine that some players would see any benefit from an arrangement as outlined.

Statnett will face a significant practical challenge in calculating the internal grid capacity in Norway that can be made available for a Norwegian auction as early as 10:00 am. In order for the participants to have a reasonable opportunity to prepare their bids, they must have information about available capacity well in advance of the auction. The solution would also create significant challenges for the capacity calculation that is coordinated throughout the Nordic region. It is uncertain whether this is practically possible - Statnett may need to assess this further.

As long as participation is voluntary, it is not obvious that the solution conflicts with EU market rules, particularly the Regulation on capacity allocation and congestion management. As far as we know, the establishment of the NSL auction was completely unproblematic in relation to this regulation - it was precisely the EU's reluctance to allow the UK to participate in SDAC that forced it forward. Excluding actors in Norway from participation in SDAC is potentially problematic, and may need to be considered further. In a recent judgement from the European Court of Justice (C-648/18, delivered in 2020), the Court concluded that it was not compatible with the prohibition on export restrictions to require national electricity producers to offer all their power on platforms managed by a designated operator for trading services on the national market. This would be an arrangement that has an effect equivalent to an export restriction and could not be justified by any relevant exception, according to the Court. The national dispute concerned whether the power producer Hidroelectrica could be required to sell all its production via a national trading platform, and not export directly through bilateral agreements. In other words, in this case, a trading platform had been introduced to monopolise the trade.

15.4.6 Rule that a share is traded outside spot, on other contracts

In Norway, power-intensive industry generally has long-term power purchase agreements directly with Statkraft and/or other producers. It is estimated that around 35 TWh of hydropower is on long-term agreements with the industry. In addition, around half of the wind power developed onshore is based on long-term contracts, so-called Power Purchase Agreements (PPAs).[56] In addition, it is now possible for hydropower producers to sell fixed price agreements to consumers with a duration of three, five and seven years.

Long-term agreements usually have a fixed price for the entire period, possibly with adjustment of the fixed price year by year according to an agreed formula. In many such agreements, the agreed price applies to a specified volume, normally also with an agreed volume per hour, day or month. Fixed price agreements for households and other small customers are made by electricity suppliers purchasing in the wholesale market, directly from the producer or with forward contracts traded on the stock exchange. Most of the long-term contracts described here are financial contracts, where the buyer (or the electricity supplier) buys the daily demand in the spot market, but secures a fixed price via the settlement with the counterparty (see section 6.1.3 for a thorough explanation of the difference between physical and financial contracts).

If we introduced a rule that a proportion of the power must be traded on physical agreements outside the spot market - for example, so that all contracts for power-intensive industry and all power sales agreements entered into by owners of wind power plants (and/or other agreements) - where the parties do not have to deal with the spot market on a daily basis, two questions arise, which we discuss below. The first question is whether two separate markets with different prices will or can develop. Secondly, there is reason to consider what such a development could mean for the spot price and for future contracts linked to the spot price.

What are the price effects of the measure?

The first question is similar to the question of whether a separate bidding zone for power exchange will result in different prices than the current arrangement. Here we can imagine that a rule is established so that a certain amount of power should not or cannot be traded in the spot market. Whether it was, for example, power for households or certain types of businesses, or a proportion of

[56] Renewable Norway: Input to the expert committee that will assess the pricing of electricity

all power production that must be traded in a separate market is not the most important thing. However, to link the reasoning to a specific example, we can imagine that all power for households must be traded in a separate market.

Electricity suppliers that will be buying for households will then reduce their purchases in the spot market, compared with what they do today. The producers will then realise that if they do not move some of their sales bids to the 'new' market, the price in the spot market will be very low. The producers will therefore divide their sales between the spot market and the marketplace for electricity suppliers.

If electricity suppliers realise that the price on 'their' marketplace is systematically higher than the prices in the spot market, it will be rational for them to reduce their purchases on their own marketplace and instead buy something in the spot market. If the producers experience the same, they will try to do the opposite - move part of their planned sales to the electricity suppliers' marketplace. This move will probably go back and forth, so that over time, prices will remain roughly the same on average.

The key point here is that the market value of the power available is not dependent on where it is sold, but on the overall supply and demand.

Now, we could set up the example slightly differently, for example, if the electricity suppliers' marketplace only had long-term contracts. If we hypothetically assumed that the electricity suppliers could perfectly predict how much their customers will consume in each hour a whole month ahead, they would not have to use the spot market to adjust their purchases. However, the result would be the same, because the producers would sell correspondingly less in the normal spot market. The scheme would remove as much production as consumption from the spot market. If a different price were to be established in the electricity suppliers' market, a ban or requirement to use specific marketplaces would have to be introduced to prevent the players from adjusting their behaviour so that the prices are the same.

The second question concerns liquidity and confidence in the price in the spot market as an information carrier for the value of an extra unit of energy. We can imagine a situation where much of the power is traded so that the parties make little use of the spot market. Until the end of the 1990s, this is how the spot market in Norway and the Nordic region functioned. The majority of all long-term contracts were physical contracts and only a small proportion of total power consumption was traded in the spot market.

One of the reasons for this development was that the players' costs of trading on the power exchange were primarily linked to a fee per kWh bought and sold. Vertically integrated companies that had both power production and power sales to end users therefore only submitted their net position as a buy or sell bid to the power exchange. If they were to both buy and sell roughly equal volumes, they would have to pay a very high volume fee.

At one point, concerns about whether the spot price was representative led the power exchange to start calculating the so-called volume fee based on the participants' net volume. If the participants did not change their assessments behind the bids, but 'only' left it to the power exchange to calculate the individual participant's net buying or selling interest, the price would be the same as before. The exchange's total fee income would also remain the same. But everyone would now know that a significantly larger volume than before formed the basis for price formation. This increased confidence that the spot price was a correct expression of the market value of power.

This in turn laid the groundwork for more and more futures trading to be structured as financial contracts - because players could trust that the settlement of financial contracts was based on market values and not just some spot price 'dictated' by individual players.

A rule that a proportion of the power must be traded outside the spot market will therefore, if it works as intended, not contribute to systematically higher or lower prices for anyone (unless it involves a trading ban or prohibition for certain players). On the other hand, it will contribute to weakened confidence in the spot market and increase costs for those who demand long-term agreements and long-term price hedging. If the rule does not succeed, it will have no effect on price formation, but then it will also be superfluous and 'only' entail administrative costs.

How does the measure affect the behaviour of actors along the value chain?
Reduced confidence in the spot price as an information carrier will initially have an impact on those who want to hedge future production or consumption. They must expect price hedging to become more expensive, as explained above.

Reduced confidence in the spot price will also mean that consumption or production that is flexible and can easily be adjusted to the spot price will not necessarily adjust consumption or production according to what is most economical for society. In practice, consumption and demand will (still) have to be linked to spot prices, but the risk that the spot price no longer reflects the value to society of a marginal change will in practice lead to the spot price sometimes being higher or lower than the value to society.

What are the consequences of behavioural changes for the power system?
Without very detailed analyses, it is difficult to determine whether reduced confidence in prices will also lead to, for example, a greater need for flexibility on the production or consumption side of the market. Similarly, as far as we can see, there is no basis for determining whether and, if so, how security of supply is affected by a rule as explained above.

What consequences will the changes in the power system have for society as a whole?
In general, increased costs for price hedging will make it difficult for players on both the supply and demand side of the market to make investment decisions. All other things being equal, this will slow down the pace of the energy transition. We have no basis to say whether the effects will be in the form of reduced producer surplus or reduced consumer surplus.

What barriers exist to implementing the initiative?
As indicated above, it is probably easy to implement the measure in a form that has no practical significance for price formation. However, if the measure is to have an impact on price formation, the most important challenge is to limit (some) players' right to choose where and in what form they want to buy or sell power. As explained in chapter 15.3 it is uncertain whether an arrangement can be found that is legally viable.

15.4.7 Norgespris - an award for consumption across the country

There are at least two different ways to achieve a common price for the whole of Norway. One method is to define the whole of Norway as a bidding zone. The other is to do as in Italy, where there is a common price for consumption throughout the country, while producers relate to seven different bidding zones.

Price effects of a single bidding zone for the entire country
Norway is currently divided into five bidding areas, see chapter 7.1. The division into bidding zones is an effective tool for managing bottlenecks in the grid and ensuring a balance between consumption

and production. Removing the bidding zones will mean that transmission constraints in the grid will have to be solved in other ways, such as countertrading, see chapter 7.1.

If the bidding zones are removed throughout the country, the same price will be paid to all consumers throughout the country. However, if the bidding zones are removed, the players will no longer receive signals through the price as to where it is most valuable for society to increase or reduce production and consumption. In areas with power shortages, all players will be incentivised to increase production while reductions in consumption are rewarded, which improves access to power and security of supply. In addition, area prices help to emphasise the need for more long-term measures in the power system.

Price effects of an Italian solution - price equalisation between consumers
Italy has seven bidding zones (Norway has five and Sweden four). However, they have a special solution that ensures that consumers in Italy face the same prices regardless of bidding zone (Prezzo Unico Nazionale (PUN) means one national price). Euphemia (see chapter 6.4) first calculates a price in each bidding zone, including the seven Italian ones. All producers are paid according to which bidding zone they are associated with. Then, an equal price is calculated for all consumers throughout the country, so that the revenue from selling at this price covers the cost of buying at the seven different zone prices (while taking into account imports and exports).

This means that consumption in low-price zones to producers actually covers some of the costs associated with consumption in high-price zones. The solution, both as implemented in Italy and in other ways of implementing a splice, means that some of the consumption in zones with a high price to producers replaces consumption in zones with a low producer price. The value creation associated with consumption that is blocked in this way in low-price zones may be higher than the value creation associated with consumption that 'enters' high-price zones due to the equalisation.

With the Italian solution, all consumers receive the same price signal regardless of their location. The price signals to the consumer side lead to a less optimal consumption pattern. It is less profitable to save in areas with high producer prices, and consumption is not as high as it should be in areas with low producer prices. It also means that the localisation signals for new consumption are weakened. This means that new consumption has less incentive to locate in a place that ensures the most efficient utilisation of resources.

How do the measures affect the behaviour of actors along the value chain?
Compared to the current situation, a common price for all operators, or only a common price for all consumers, will affect consumption decisions and possibly production decisions. As outlined above, consumption in today's bidding zones with high prices could be somewhat higher, while consumption in bidding zones with relatively low prices will be somewhat lower. In the long term, operators' investments may also be affected because price equalisation affects their expected revenues or costs.

What are the consequences of behavioural changes for the power system?
With a common bidding area for the entire country, Statnett will to a lesser extent than today be able to use the results of the spot market to check that the players' plans for tomorrow can actually be realised and that the grid capacity is sufficient. A practical consequence could be that the final deadline for balance responsible parties to notify Statnett of planned production and sales must be brought forward and be earlier than the current deadline of 45 minutes before the operating hour. This could mean that Norwegian market participants may not be able to participate in the intraday market for as long before the operating hour as their Scandinavian colleagues. In the long term, this may mean that it will be difficult for Norwegian players to realise the market value of their flexibility. This applies to both production and consumption (industry).

Some of the social costs that are currently expressed as price differences between bidding zones will, with the outlined change, instead come as costs for Statnett for countertrading and other measures to ensure that the market participants' plans can be realised. Based on experience from Germany, there is reason to believe that the costs of countertrading are higher for society than the solution we have in Norway today. In a pure hydropower system such as Norway's, systematic countertrading in a region can jeopardise security of supply.

Both joint price models will also affect neighbouring countries. As mentioned in the fact box on capacity (chapter 5.6), the capacity between bidding zones depends on the distribution of production and consumption between bidding zones. If Norway is reduced from five to one bidding zone, the information that can be communicated to the market about trading capacity will be less detailed and less consistent with the physical realities of the grid. Unless the solution is similar to the upcoming Italian scheme, the details of which are not yet finalised, the change will likely fall under the rules for bidding zone changes (CACM). The process is regulated in detail to ensure that all countries, regardless of size, have equal influence over changes that could negatively impact neighbours. Such a process can take several years to complete.

What barriers exist to implementing the initiative?
A practical challenge with the exact solution used by Italy is that it delays the calculation of the spot price for all other bidding areas in Europe. The European power exchanges have therefore notified the Italian authorities that from 2025 they will no longer calculate PUN as an integral part of the market solution. Instead, they will create a post-calculation that calculates the price Italy must have throughout the country in order to minimise the costs of a common national price.

As explained above, there will also be legal challenges related to the interests of neighbouring countries. The division into bidding zones is not exclusively an internal Norwegian matter - it has direct economic significance for our neighbouring countries.

15.4.8 Introduction of maximum price in the wholesale market
Setting a maximum price has been discussed several times. This can be done in the wholesale market or in the retail market. We look at a maximum price in the retail market in Chapter 17.5.1.1.1, and here we concentrate on assessing a maximum price in the wholesale market.

Here, we envisage a rule that prevents power producers from submitting a bid that exceeds a fixed maximum price set by the Norwegian authorities. Which level it should be set at is then an important decision, but it is assumed in the assessment below that it is well below what has been the market price during the electricity price crisis and closer to a historical average price.

What are the effects of the measures on prices and security of supply?
A maximum price that is set well below the market price during the electricity price crisis will naturally lead to lower and more predictable prices, as a ceiling is set for how high the price can be. Given that the maximum price is lower than the market price in neighbouring countries, this also results in competitive prices.

If the maximum price is set lower than the water value, this is in practice what sets the opportunity cost. In practice, this means a maximum value for the water value. There will therefore be no incentive to save water, as the producer will not receive more for the water later. Producers will produce more than they would otherwise have done in the current season.

Similarly, consumers will have weaker incentives to save electricity. This means that consumption will be higher than it would have been.

If the maximum price is also below the price in other countries to which we have transmission connections, more electricity will be exported than would otherwise be the case. In this situation, a maximum price means that we sell electricity abroad more cheaply, reducing the value creation from Norwegian hydropower.

As the Norwegian hydropower-based system is limited on the supply side of the inflow to the reservoirs, this development poses challenges over time. As the price no longer signals scarcity, the reservoirs will be drawn down further than they would otherwise have been. There is then a risk that security of supply will be jeopardised and that situations involving rationing will occur far more frequently than in the current situation.

If, in a situation of scarcity here at home, we have a maximum price that is higher than in neighbouring countries, we can import power and thus ensure security of supply. If, on the other hand, the maximum price is lower than the prices around us, no power will be imported and we will have to handle the situation with rationing.

If we are to avoid a maximum price that is set below the price in other countries leading to exports, it is necessary to limit exports to other countries. There are several ways to do this, some of which are discussed in this chapter in section 15.1 and 15.2and in chapter 12. Even if we manage to reduce exports, we are dependent on imports in a shortage situation, not least in dry years. And even if neighbouring countries do not react by reducing our import opportunities as a consequence, we will not import as long as the maximum price is below the market price in other countries.

What are the effects of the measures on other parts of the power system?
A maximum price sets a ceiling on how high the price can be. This weakens the incentives for operators to invest in new production, and it weakens consumers' incentives for energy efficiency.

A maximum price that is lower than market prices in neighbouring countries provides incentives for new industry to locate in Norway. This means that demand increases, but if the maximum price does not provide sufficient incentives for new power production, the resource balance will deteriorate further and security of supply will become increasingly vulnerable.

To avoid this, mitigation measures can be implemented. This can involve either refusing to connect new consumption to the power system, subsidising the expansion of power production or energy efficiency, or subsidising flexibility in consumption.

What barriers exist to implementing the initiative?
The biggest barrier to implementing the measure is that a number of measures must be taken by the authorities on an ongoing basis to ensure the balance in the system in the short and long term when the price no longer reflects the physical resource situation. If this is not to be at the expense of efficient resource utilisation and security of supply, it must be assumed that a central authority may have better information about the reservoir situation and inflow conditions than is reflected in the market price.

15.4.9 Stimulate liquidity in the futures market using EPAD

Improved liquidity in the futures market (see chapter 5.7.1 and 6.1.3) can make it easier and more affordable for electricity suppliers to offer fixed-price contracts to households and small and medium-sized enterprises. This can result in more stable and predictable prices for consumers.

One concrete possibility is that Statnett is commissioned to engage in the market for EPAD contracts. EPAD stands for Electricity Price Area Differentials, and is used to hedge the difference between the spot price in a bidding area and the so-called system price (see chapter 6.4.4). In Sweden, Svenska kraftnät has a pilot project where they offer to be counterparties for EPAD contracts through an auction (Svenska kraftnät 2023). The idea is that if this is successful, it will become a permanent arrangement where the aim is for Svenska kraftnät to contribute to strengthening liquidity in the Swedish part of the forward market.

Below we discuss the effects of Statnett being given a similar assignment - to participate in auctions of EPAD contracts between bidding areas in Norway and on the borders of one or more neighbouring countries. A precise description of the details of the programme would take up too much space, so we refer instead to Svenska kraftnät's own description (Svenska kraftnät 2023).

What are the price effects of the measure?
Judging by experience in Sweden, the measure will strengthen liquidity in the forward market, particularly for Norwegian EPAD contracts. Through this, the measure will contribute to an increased supply of fixed price contracts that can provide more predictable and stable prices to consumers.

How does the measure affect the behaviour of actors along the value chain?
For consumers, increased liquidity in the forward market will help to reduce the cost of hedging by enabling electricity suppliers to find suitable price hedging more efficiently. At the same time, fixed price contracts may reduce consumers' incentives to be flexible and invest in energy efficiency, but this primarily depends on how fixed price contracts for end users are designed. The specific measure here (Statnett's participation in the market for EPAD contracts) only has an indirect effect on electricity customers.

For power suppliers, better liquidity in the forward market enables them to offer more attractive fixed-price products to end users.

For power producers, this means better opportunities to hedge parts of their power production and thus their cash flow for a period of time. This can make it more affordable for power producers to get other players to bear some of the risk, thereby reducing barriers for small or new players on the supply side of the market in particular.

What are the consequences of behavioural changes for the power system?
Depending on the scope and design of fixed price contracts for electricity customers, the motivation for flexibility may be affected, see Chapter 16.6.

What consequences will the changes in the power system have for society as a whole?
The measure is unlikely to have major distributional consequences between the various players in the value chain.

What barriers exist to implementing the initiative?
On a practical level, guidelines must be drawn up for Statnett's involvement and for the practical implementation of EPAD auctions. Experience from Sweden is relevant for a Norwegian solution. They indicate that the measure is, after all, relatively easy to implement in purely practical terms.

One conceivable objection to such a scheme is that Statnett, with such a role, begins to resemble a normal player in the market. If we look at the specific example from Sweden, the situation is that Svenska kraftnät's role is limited to matching buy and sell orders for EPAD in different bidding areas, upwards limited to a certain volume that depends on the transmission capacity between the bidding areas. They do this without taking a position on the prices in the bids, but they ensure that players in neighbouring areas can indirectly trade with each other. This can also be organised so that the method for defining the volume limitation is completely objective and 'mechanical'. In this way, Statnett's potential opportunity for market manipulation will be very small, not least in practice.

On the other hand, it is important to look at the experience from Sweden, which has so far been predominantly positive. The fundamental challenges are important factors, but do not present unsolvable problems.

At the legal level, the starting point in the Regulation on the establishment of guidelines for long-term capacity allocation (FCA)[57] Article 30 states that if national regulatory authorities (RME in Norway) consider it appropriate, system operators are obliged to contribute to strengthening liquidity in the future markets. Most system operators in Europe do this by auctioning long-term transmission rights. In connection with the evaluation of the current regulations, ACER has recommended a solution that is very similar to the one Svenska kraftnät is trialling. We therefore assume that if a prior analysis by RME concludes that auctioning EPAD contracts in a manner similar to Svenska kraftnät's approach can strengthen liquidity in the future market, and if this is implemented in a well-considered manner, this will be fully in line with European regulation.

15.5 Information measures aimed at the wholesale market

15.5.1 Increased focus on security of supply in the manoeuvring regulations for reservoirs

A report from SINTEF (2023) examined the producers' reservoir allocation in autumn 2021. The report points out that during this period the market underestimated what could happen in the future, and that production was greater than an optimal production based on expectations that were reasonable to assume (forward prices) would indicate.

A consultation paper[58] points out that some quarters have argued that Norway has left too much of the responsibility for security of supply to the market, and that hydropower producers do not have a sufficiently clear responsibility to contribute to security of energy supply. The consultation paper presents a proposal for a stricter focus on security of supply in the Watercourse Regulation Act and in relation to the companies' planning of reservoir manoeuvring.

A permanent control mechanism is proposed whereby the authorities can intervene in stages to control reservoir utilisation in the interests of security of supply. The steps involve increasingly greater intervention in the hydroelectric power producers' utilisation of the water**.**

The consultation paper states the following (page 10):

> "The instruments will work in stages, with the new purpose clause on security of supply and the requirement to prepare utilisation strategies at the bottom. If the power situation becomes more demanding, the first step will be for the authorities to require power producers to report on production and forecasts for reservoir filling. In addition, the authorities can demand access to the utilisation strategies. If the power situation deteriorates and extraordinary circumstances indicate that there may be a shortage of energy, the authorities can intervene in relation to the producers. In such a situation, power rationing will be introduced. In the event of power rationing, it will also be possible to order Statnett to limit exports if this is necessary to ensure security of supply."

[57] Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

[58] Consultation - proposed amendments to the Watercourse Regulation Act, the Energy Act and associated regulations (management mechanism for security of supply) - regjeringen.no

How does the measure affect the behaviour of actors along the value chain and what are the price effects?
There is little reason to believe that the authorities have a better basis for assessing uncertainty than the many hydropower operators who monitor the situation on a day-to-day basis. On the other hand, it is conceivable that the authorities will have a different assessment of the level of reservoir filling that is necessary to ensure security of supply. This would mean that the introduction of the control mechanism could result in more water being held back in the reservoirs than would otherwise be the case.

A step-by-step approach will give hydropower producers increasingly strong signals from the authorities that it is desirable to withhold more water. If the authorities choose to implement the first step, requesting that hydropower producers report on production and forecasts for reservoir filling, hydropower producers will take this as a signal that the authorities are considering introducing more measures. The next step is to demand insight into the dispatch strategies of the producers, and ultimately power rationing. The prospect of the authorities taking the next steps is likely to result in hydropower producers withholding more water than they would otherwise have done.

When hydropower producers hold back more water, prices will increase. As there is more water in the reservoirs for use later in the winter, more can be produced and prices will be lower than they would otherwise have been. It is conceivable that over several years, hydropower producers will adapt to a situation where they maintain a higher reservoir filling level than before in order to avoid measures. This will probably weaken the price effects.

It is difficult to estimate the overall effect, but as water reservoir utilisation becomes more cautious, it will probably mean a slightly higher price over the year. As prices rise slightly in the autumn and decrease slightly in the winter, this suggests that prices will be somewhat more stable. Somewhat higher average prices imply weaker competitiveness.

The somewhat higher average prices would then mean somewhat stronger incentives for energy efficiency and investment in more production, which in itself helps to strengthen security of supply .

It is unlikely that the measure will affect the behaviour of electricity suppliers.

What are the consequences of behavioural changes for the power system?
The control mechanism allows the authorities to intervene in the hydropower operators' reservoir utilisation when they have a different risk assessment than the operators. The measure is likely to strengthen security of supply. However, it is not obvious that the authorities' assessment is better than the operators' and that the measure is therefore necessary to achieve a defined security of supply at the lowest possible cost. Resource utilisation will therefore be less efficient with the measure than without it. The increased cost can be seen as an insurance premium we pay to strengthen security of supply.

The measure will affect the players' reservoir allocation and mean that trade with other countries will be staggered in time. The same amount will be produced as before, but exports and imports with neighbouring countries will take place at a different time, and the composition of which countries are exported to and imported from will change.

What consequences will the changes in the power system have for society as a whole?
The producers' reservoir utilisation will become less efficient, and they will probably receive less income. This will have consequences for the owners of the power companies, who will receive less dividend. The state will partly receive less dividend from its ownership of Statkraft, but will probably receive higher revenue as a result of a slightly higher electricity price from players that do not have a

reservoir. Consumers will see somewhat higher average prices and lose out, but on the other hand they will benefit from somewhat more stable prices.

If a situation arises where the authorities make a different risk assessment than the players and implement measures that prevent a situation that would otherwise have ended in rationing, the picture looks different. It is unclear what consequences rationing has for producers' earnings, but for consumers, the benefits of avoiding power rationing are very high.

15.5.2 Better description of volatility in public price forecasts

From time to time, Statnett and NVE produce publicly available price forecasts or scenarios for the power market. The analyses behind such forecasts are normally very extensive. The models used produce an iceberg of figures, and the public reports can only publish a small part of the tip of the iceberg.

Experience shows that it is easier to communicate few numbers than many numbers. The impression left, especially among those who do not read such reports from cover to cover and with as much attention to the footnotes as to the headlines, is often that the publisher believes that prices in x years will be y øre/kWh - not that they will with a certain probability be in the interval between a and b, and with a certain risk may be so and so much higher or lower than this. But even experienced readers often have to search long and hard to find good information about the entire probability distribution for prices that the analyses have actually calculated. This is probably a natural consequence of all the circumstances associated with such forecasts.

Nevertheless, there is reason to consider whether better information about price uncertainty and, not least, the prospects for variation in power prices could be valuable. A banal example can illustrate the point: A normal dice has six sides with numbers from one to six, and an equal probability for each number. The expected value for a roll of the dice is 3.5, but it is also a value you will never see in a single roll.

Good information about price uncertainty and price volatility is important for assessing things as diverse as the value of flexibility in the power system and the distributional effects of various measures. The value of flexibility is important, for example, to assess the benefits and value of (better) opportunities to adjust consumption in simpler ways, investments in energy storage, or investments in power plants that can primarily produce when the value of power is particularly high. Assessing distributional effects is particularly important for the authorities' own assessments of specific policies and measures that require a licence from the authorities.

A relatively simple measure is therefore to place somewhat higher demands on the dissemination of information when the authorities or Statnett present their forecasts. Readers must be able to familiarise themselves with the range of outcomes for prices and the factors that have a major or minor impact on this range just as easily as they can read expectations about price levels or what is perceived as the most likely development. How this is communicated by the media is obviously beyond the control of the authorities. Nevertheless, it is possible to work purposefully towards a more complete information picture.

We assume that the major players who create their own scenarios and forecasts have a good basis for their own independent assessments. This mainly applies to power producers and advisers in the energy industry. The measure will therefore mainly be relevant for smaller players and not least for households, in addition to anyone involved in policy and the design of measures and instruments related to the energy market.

What are the price effects of the measure?
The measure as such is not expected to affect prices in the short term. If the measure leads to greater investment in flexibility in the power system, the result in the longer term will probably be lower and less variable prices than we would otherwise have had.

How does the measure affect the behaviour of actors along the value chain?
In the long term, the measure may increase interest in making electricity consumption more flexible and investments in energy storage, primarily among smaller players, such as households and general business operators.

What are the consequences of behavioural changes for the power system?
The measure can potentially contribute to somewhat higher security of supply and more efficient resource utilisation.

What consequences will the changes in the power system have for society as a whole?
Better knowledge of the variability and range of outcomes for electricity prices, both under normal circumstances and if the market is exposed to some form of shock, creates better conditions for more accurate measures aimed at unfavourable or undesirable distributional effects.

What barriers exist to implementing the initiative?
Apart from the fact that it is demanding to communicate information from work on power price forecasts in an effective manner, the Committee does not see any obstacles to raising the level of ambition with regard to such information.

15.5.3 Better knowledge of price elasticity

Many were concerned about whether the reservoir levels at the start of the winter of 2022/2023 would be sufficient to ensure power supply throughout the winter until the snowmelt normally starts in April/May. The most feared scenario is that the authorities will have to implement rationing. Rationing means, among other things, that customers cannot decide how much electricity they want to use and producers cannot decide how much to produce.

Whether rationing will be necessary will generally depend on i) reservoir levels at the start of the tapping season, ii) consumption during the winter, iii) precipitation and inflow during the winter, and how precipitation is distributed between water and snow, iv) power exchange with foreign countries during the winter, and v) when snow melting starts. A combination of high consumption, low precipitation, a high proportion of precipitation as snow, high net exports and a cold spring with late snowmelt, all else being equal, results in the highest probability that rationing will be necessary.

If the probability of rationing becoming necessary during the winter is considered relatively high during the summer and autumn, it will be rational, both for the individual producer and for society, to produce less hydropower from reservoirs during the summer and autumn than would otherwise have been the case. All other things being equal, this will mean that power prices in summer and autumn will be higher than they would otherwise have been.

The government's decision to impose a reporting obligation on hydropower producers must be seen in this light.[59] It was desirable to ensure that hydropower producers were aware of the risk of rationing and thought carefully before making production decisions 'now'.

In this context, we can note that the assessment of the likelihood of rationing depends, among other things, on what is assumed for consumption trends until the snow melts. Will households and

[59] Letter to the Storting from Minister of Petroleum and Energy Terje Aasland on 15 August 2022 (https://www.regjeringen.no/no/dokumenter/g/id2924313/).

businesses reduce their consumption significantly if prices are high throughout the autumn and winter, or will they use electricity more or less as normal? This depends partly on conditions outside the power market, such as temperature (if it gets cold, consumption will be higher than in a warm autumn and mild winter), the level of activity in industry (if metal prices are high enough, power consumption in the metal industry will be higher than if metal prices collapse), and partly on power prices. If price elasticity is assumed to be high, an analysis will show that the probability of rationing is lower than if price elasticity is assumed to be low.

In retrospect, it may be questioned whether the analyses behind the control mechanism announced by the government on 15 August 2022 have different assumptions about the price elasticity of consumption than the power producers themselves assume. The Committee has not taken a position on whether this is the case or not. However, what does stand out as a potential measure is to ensure that the power producers and the authorities use roughly the same assumptions about price elasticities as the basis for their respective analyses, and that these assumptions are as realistic as possible.

Power producers and the authorities use roughly the same modelling tools for production planning and monitoring and supervision of the market and security of supply, respectively. Both 'parties' are dependent on choosing assumptions that are as correct and realistic as possible in order to make decisions that are best for society.

One concrete measure could therefore be for the authorities and power producers to a) work together to gain better knowledge about the price elasticity of electricity and b) develop routines for exchanging experience and knowledge about price elasticities that they use in their respective analyses.

In this context, we are referring to assessments of relatively short-term price elasticity, roughly in the interval between a few weeks and six to nine months. The research literature on price elasticities is varied and does not necessarily reflect the need we are emphasising here (DNV og Vista Analyse 2022). Nor is it obvious that traditional empirical analyses of price elasticity are the best way to achieve the goal of better knowledge; the committee has not considered how this can be achieved.

What are the price effects of the measure?
Whether this measure leads to higher or lower prices than we would otherwise have had depends on the extent to which and in what way information about the risk of rationing used in production planning changes. Whether they become more stable, more predictable, higher or lower cannot be answered in general. In general, it can be argued that prices more accurately reflect society's real value of power the more correct and relevant information is used as a basis for the producers' planning and for the authorities' follow-up.

If the power producers in autumn 2022 had assumed a lower price elasticity than they actually did, they would have withheld more water, produced less that autumn and the spot price in the autumn would have been higher. In autumn 2022, the risk of energy loss via some overfilled reservoirs would also have been somewhat higher, while the outlook for the price over the winter could have indicated lower prices than otherwise assumed in autumn 2022. The opposite also applies - if a higher price elasticity had been assumed than was actually the case, prices through the autumn could have been lower and prices over the winter higher than they would otherwise have been.

How does the measure affect the behaviour of actors along the value chain?
More socially correct prices also result in more correct production decisions and reservoir utilisation, as well as more correct adjustments on the consumption side. If the measure affects investment decisions, it will be in the direction of more socio-economically rational decisions.

What are the consequences of behavioural changes for the power system?
Better information will provide a better balance between high security of supply and low power prices. The utilisation of society's resources and trade with foreign countries will become more efficient, also from the perspective of foreign countries.

What consequences will the changes in the power system have for society as a whole?
Since it is not possible to say in general whether prices will be higher or lower, but nevertheless that they will be more correct in a socio-economic sense, it is reasonable to claim that the measure will contribute to an improvement for all parties.

What barriers exist to implementing the initiative?
The initiative addresses a classic barrier to efficient pricing and efficient resource allocation - lack of or insufficient information - with the aim of reducing this barrier.

Legally speaking, there is nothing to prevent either a better knowledge base in general or the sharing of information between an industry and the authorities. However, the Competition Act contains a general prohibition against co-operation among producers. In the power market, the Norwegian Competition Authority has been particularly concerned that power producers should not discuss strategies for reservoir allocation among themselves, beyond purely technical issues such as how to technically model certain conditions. If the industry or the authorities wish to follow up this measure, they must therefore take this into account and ensure that the work is organised in such a way that it does not harm competition between the players.

15.5.4 Information from operators to TSO, RME

Statnett and RME always have access to more detailed information about reservoirs, water flow and consumption than the market players. If either of them, in their routine monitoring of the power situation, find reason to be concerned about the situation, for example if reservoir drawdown appears to be faster than they had expected, or if consumption develops unexpectedly, RME and NVE have several authorisations to request more information. This applies in particular to information related to the hydropower plants and reservoirs. These authorisations have been strengthened over time, most recently through proposals for the so-called steering mechanism and through amendments to the rationing regulations. Already when Statnett first launched a systematised overview of relevant measures for use in very strained power situations, the collection of more (detailed) information from the hydropower operators was listed as one of the least invasive measures that could be taken (Statnett 2005).

However, the Committee cannot rule out the possibility that even more information from market participants may be useful in certain situations. For example, power producers or electricity suppliers may have insight into the flexibility and price elasticity of consumption among households and various businesses, which may be valuable when assessing the likelihood of a serious energy shortage and the possible need for rationing. Similarly, it is conceivable that businesses in power-intensive industries know more about their own situation than the authorities know or than they wish to share with the authorities.

The Committee has not considered how and whether this should be designed as a specific measure. However, below we discuss what more and better information from the players could potentially mean. We assume that this is potentially most relevant when there is a shortage or prices are relatively high for other reasons. However, the Committee cannot determine that there is a need for better authorisations to obtain information or better incentives to share information from the players.

What are the price effects of the measure?
If anything, it is reasonable to believe that better information from the authorities about the players' situation may contribute to somewhat lower prices when the system is under severe stress. The reason for this is quite simply that when Statnett, for example, assesses the likelihood of rationing, the company may consciously or unconsciously be cautious in its assessment of the adaptation options on the consumption side, rather than overestimating flexibility. It is quite natural to emphasise being cautious and not taking the situation too lightly.

Public analyses of, for example, the likelihood of rationing will affect producers' calculations of water value, especially for producers who do not carry out their own independent analyses of the risk of rationing. If they assume that the risk of rationing is greater than it actually is, this may result in the price level (until the risk is over) being higher than it would otherwise have been.

How does the measure affect the behaviour of actors along the value chain?
Better information to Statnett and RME can potentially result in qualitatively better analyses and decisions.

What are the consequences of behavioural changes for the power system?
At best, the consequences of the measure are better resource allocation and utilisation of the infrastructure in the energy sector. To the extent that the measure actually leads to lower prices in some situations, it will help to maintain value creation that would otherwise have been less or not taken place. Otherwise, the proposal has no impact on the players' adaptation or on the power system.

What consequences will the changes in the power system have for society as a whole?
(Even) better information from the actors about their situation contributes to a better match between the authorities' situation analysis and the actual situation, especially in potential scarcity situations.

What barriers exist to implementing the initiative?
The Commission has not assessed whether better information requires new authorisations for RME or Statnett. The actual information potential should be clarified before ensuring access to information.

In practical terms, we do not see any significant barriers, but one must consider the extent to which the players, especially on the demand side of the electricity market, can be expected to see themselves as benefiting from providing a completely accurate description of their own opportunities, for example to temporarily reduce consumption. In the worst case, it may be profitable for the individual player to give a misleading presentation.

15.5.5 Public information about the authorities' and Statnett's assessments

Certain routines have already been established for sharing information with the general public if the power market moves out of the normal situation. In the last couple of years, many people have become familiar with Statnett's use of colour codes to indicate how they assess the risk of rationing being necessary to ensure equilibrium between production and consumption.

For many people, it is difficult enough to consider these colour codes and understand what they mean for their own situation. It is not obvious that better or more information makes it easier. Nevertheless, it may be appropriate to investigate more systematically whether there is more information that could or should be shared with the public, or whether the information should have been shared in other ways.

What are the price effects of the measure?
Better information on how the authorities or Statnett assess a potentially demanding situation does not have a clear impact on the price. The value will rather be that the players' own basis for decision-making will improve, as it must be expected that the authorities will spend more resources on analyses than the individual player.

How does the measure affect the behaviour of actors along the value chain?
Better information about how the authorities assess a potentially serious situation can potentially create greater understanding that consumption must be reduced to avoid more serious situations later on.

What are the consequences of behavioural changes for the power system?
Better information generally means (the possibility of) better decisions, but we can't point to specific behavioural changes.

What consequences will the changes in the power system have for society as a whole?
Apart from potentially better and more relevant decisions by the players, we have no basis for identifying specific consequences.

What barriers exist to implementing the initiative?
As far as the Committee can judge, the authorities and Statnett are fairly free to tell the public how they assess a current situation.

15.5.6 Public information about the players' adaptation to very high prices

The discussion that has taken place in recent years indicates that society would benefit from better knowledge and information about the players' adaptation to higher prices, and that discussion about this and the normal functioning of the market should be disseminated more systematically in the public domain. The Electricity Price Committee's mandate can be understood against this background.

To the extent that we can call this a concrete measure, it can be understood as the authorities systematically and purposefully contributing to more public discussion and information about how producers and various consumers react to high prices. A variation of this is discussed in chapter 15.5.4 above. While that measure is discussed on the basis that the target group for who should be informed is the authorities and power producers, this measure has a broader target group.

What are the price effects of the measure?
As for the proposal in chapter 15.5.3 no general effect on prices can be determined.

How does the measure affect the behaviour of actors along the value chain?
More public discussion can contribute to a better knowledge base about price elasticities and to better dissemination of such information. A better knowledge base, both on price elasticities and on the functioning of the market, contributes to more precise and better policy formulation, and to a better basis for investment decisions in power generation, grid and consumption. Beyond this, it is difficult to point to any specific likely changes in behaviour.

What are the consequences of behavioural changes for the power system?
The measure can hardly be expected to have direct consequences beyond better and broader dialogue and discussion about how high prices affect the supply and demand side of the market.

What consequences will the changes in the power system have for society as a whole?
Better and more publicly available information about what to expect when prices are very high has, at best, a favourable effect on policy-making in society. At worst, better information about this has no demonstrable effect.

What barriers exist to implementing the initiative?
The Committee cannot see that there are any barriers to this measure (other than the actual costs of preparing and disseminating information).

16 Measures aimed at the retail market

We have defined the retail market as everyone who buys electricity for their own consumption, including households, businesses, the voluntary sector, municipalities and other customers. The main challenges in the retail market discussed in chapter 8 are:

- Information about agreements is difficult to access and understand
- Uncertainty about the credibility of electricity suppliers
- Large market share for the largest electricity suppliers can be anti-competitive
- The risk of being a completely passive customer will increase in the future
- There are several barriers in the market for price hedging:
    - Lack of information to customers about expected future developments
    - Low demand in the market today - the market becomes less efficient and supply becomes more expensive
    - Limited opportunities for price hedging and collateral requirements for electricity suppliers limit supply
    - Information asymmetry about price levels - more difficult for customers to assess fixed prices than spot prices
    - The temporary electricity subsidy programme functions as a quasi-fixed price for household customers, removing the incentive to enter into a fixed price agreement

Rectifying these market failures can contribute to lower prices by making the market more efficient, and to more predictable prices by improving access to price hedging for customers.

This chapter describes different types of measures to rectify market failures, both less invasive measures, such as information, and major reorganisations, and assesses the extent to which these measures could have a positive effect on the market and thus contribute to lower prices to customers. The measures discussed in the chapter are measures that are raised in the discussions on the retail market and measures that the Committee has received input on. The list of measures is therefore not a list of measures that the Committee believes should be implemented; the purpose of the chapter is to review different types of measures and assess their consequences.

As discussed in chapter 8 however, rectifying market failures will not result in lower prices than the wholesale market price of electricity. If the authorities want to ensure that customers receive lower prices than those set by the wholesale market, this must be done through some form of support scheme or other form of redistribution. Such measures are discussed in chapter 17.

16.1 Trade-offs between competition and regulation

A number of different measures have already been taken to improve the retail market for electricity, but more measures can still be implemented both for general market improvement and for a better market for fixed price agreements.

Some of the measures that can be implemented in the future do not require major changes to the framework, but may include information about the market and agreements and clarification of existing regulations. It is also possible to make changes to the framework conditions that facilitate more diversified supply and demand without directly intervening in the market.

Increased use of governance, either through regulatory requirements in the market or through reorganisation, will provide a greater degree of predictability, but will typically result in higher costs than a well-functioning market solution, especially over time. More direct requirements, orders and prohibitions in the market can provide a greater degree of transparency for customers, but are more difficult to design accurately, have possible negative effects on the development of the supply side and can lead to higher costs for customers overall. Greater price fluctuations in the wholesale market in the future indicate that a good and diversified offer to customers will become increasingly important.

Oslo Economics points this out in its report to RME (Oslo Economics 2021):

> *The goal of a well-functioning retail market for electricity encompasses both a goal of well-functioning competition in the short term (resource efficiency) and well-functioning competition in the long term (innovation). Basically, the aim is to introduce measures that contribute to both of these sub-goals.*
>
> *However, when it comes to the practical design of measures, there may be a need to balance these considerations. Some measures that regulate the behaviour of operators may have a positive effect on short-term competition and efficiency, but reduce innovation and thus competition and efficiency in the long term.*
>
> *For example, it is in principle possible to eliminate the problem of asymmetric information by regulating the market very strictly. This could provide a clear and efficient market in the short term, and ensure better terms for inactive customers than today. At the same time, it would remove incentives and opportunities for innovation, and would probably result in the customer receiving a poorer offer in the long term.*

Reorganisation and more regulation can have advantages in that uncertainty for customers is reduced or eliminated, as they do not have to consider different choices. It can provide increased predictability and transparency, and it can also contribute to increased confidence in the electricity supply service. Surveys show that customers find this market difficult to relate to today and they may feel cheated when entering into an agreement.

The downside of increased regulation is that, compared with a well-functioning market, it has a negative impact on costs and supply. There is basically nothing to suggest that, for example, a state-appointed operator will make electricity supply more cost-effective than a market with electricity suppliers. On the contrary, lack of competition and lack of incentives to operate cost-effectively at the supplier level can lead to costs increasing over time. Payment for the service must be regulated to avoid customers paying too much.

A lack of competition can also result in poorer offerings for customers. This is particularly relevant as we expect that a wide range of products and additional services that equalise costs will become more important in the retail market in the future. One example of this is automation and consumption management. Instead of the current situation where households mostly have spot price agreements, they may wish to hedge prices in whole or in part for shorter or longer periods of time. A well-functioning market will generally have greater incentives to develop customised products than a regulated player.

Measures for reorganisation therefore appear to improve the market when other measures are not sufficient to address the identified market failure, and when it is considered that the positive effect of more transparency to customers outweighs the loss of efficiency through regulation.

One assessment that can be made in the trade-off between market solutions and governance is, for example, the impact and risk for different types of customer groups. As described, the retail market for electricity will increasingly require customers to make choices in the future, and the risk and thus the cost of being a passive customer and not making choices will increase. For a number of customers, this may be manageable, and customers may also have a willingness to pay for not engaging in the market. Vulnerable households will have the greatest impact (in terms of consequences for the household budget) by not actively considering what is the best solution.

16.1.1 Relationship to EEA regulations

The EEA regulations do not restrict the authorities' right to provide information about current regulations or other less invasive measures. However, measures to improve the retail market must be assessed in relation to the state aid rules and also in relation to secondary legislation, such as the Third Electricity Market Directive.

Given the committee's mandate and time frame, there has not been room for in-depth analyses of possible EEA law issues related to the individual measures. Consequently, this must be done if the authorities choose to proceed with any of the measures. The description of the measures includes some considerations regarding EEA law where the Committee has now recognised that there may be relevant issues. The Committee has also received notes from Professor Erling Hjelmeng and lawyer Gjermund Mathisen on Norway's room for manoeuvre for measures in the electricity market under the EEA Agreement (Hjelmeng 2023, Mathisen 2023).

16.2 Consequences of increased use of fixed price agreements and price hedging

A number of the measures to improve the market relate to the market for price hedging and fixed price agreements. As described in chapter 8 it is reasonable to assume that demand for fixed price agreements will increase with more unpredictable electricity price levels, and that customers will have a willingness to pay for predictability in their electricity costs. A key aspect of the Committee's mandate is to assess measures that can give customers more predictable prices.

The Consumer Council has historically recommended that electricity customers have spot price agreements, on the grounds that this has resulted in the lowest cost over time. The Consumer Council now points out that customers have historically been best off with a spot price agreement, but that the future development of the electricity market is uncertain, and fixed prices may be a good alternative for customers who want to insure themselves against fluctuations and future price peaks.

We do not treat increased use of fixed price agreements as an end in itself. The aim of improving the market is that customers should have enough information to make an informed decision about whether they want a fixed-price contract, and that there should be no supply-side barriers to offering these products. If customers still do not want to enter into a fixed price agreement, this is not a market failure.

However, it is reasonable to assume that a better fixed price market for electricity will lead to increased use of fixed price agreements. This will give customers more predictable electricity prices. At the same time, it may have consequences for the power system compared with the current situation where the vast majority of households and large parts of the business sector have spot price contracts.

Increased use of fixed prices may result in electricity customers having less incentive to adjust their consumption levels, and thus less flexibility in demand when prices change. Less price sensitivity will mainly have consequences for the power system if the price level in the fixed price agreements is lower than the spot prices, because:

- High consumption during hours of high load (peak load) can cause power problems
- High consumption during periods of tight market conditions and high prices can increase the risk of rationing

How big these consequences will be, however, depends:

- What proportion of customers have fixed price agreements
- Whether customers have a fixed price for all or only part of their consumption
- If the fixed price agreement is designed so that customers bear the volume risk[60] themselves
- Whether other measures are taken for customer flexibility, such as automating consumption according to price level

The fixed price agreements for industry and large parts of the business sector are generally designed so that customers bear the volume risk themselves. This means that these electricity customers are still exposed to spot prices, and thus have roughly the same incentive to adapt their consumption to the availability of resources as they would have had if they were on pure spot price agreements.

We do not consider the removal of the electricity subsidy scheme as a separate measure to improve the market for fixed price agreements, but the overall use of instruments should be considered when designing policies for price protection for customers.

16.3 Basis for assessments of measures

In the review of various measures, we discuss the effect on the basis of the following parameters (not all are relevant for all measures):

- To what extent does the measure mitigate the identified market failures
- What could be the effect on price levels and predictability
- To what extent does the behaviour of market participants - customers, electricity suppliers and power producers - change and what impact does any change in behaviour have?
- Does any change in behaviour affect the functioning of the power system and security of supply
- To what extent does the measure affect incentives for energy efficiency
- Feasibility of the measure and relationship to the EEA Agreement

16.4 Measures to improve the current market

Overall, improvement measures in the market can be:

- information and changes in market conditions
- regulation of the market

In general, information measures enable a more well-functioning retail market. Better and more understandable information about the market provides increased opportunities to make informed choices. Facilitating the development of new products and new purchasing strategies on the consumer side can also improve the market by increasing choice.

Regulatory measures that intervene in the market, e.g. through injunctions or bans, may be accurate in terms of the problem they address, but there is also a risk that there may be negative consequences in another part of the retail market - for example, if a type of ban is difficult to define accurately and therefore restricts more product types than intended. Typically, an increased degree of regulation may lead to a less efficient market and impose restrictions that increase costs compared with a well-functioning market solution. When assessing this type of measure, the positive effects of the measure must therefore be weighed against the negative market effects.

[60] The uncertainty associated with how much customers will consume. For example, a fixed volume agreement places the volume risk on the customer.

16.4.1 Information and framework conditions

16.4.1.1 Information to customers

More information initiatives for customers can be followed up in the future:

General information

- One of the information barriers for electricity customers may be that it is difficult to compare surcharges and thus costs for different types of contracts. Some contracts have a surcharge in the form of a fixed monthly amount, while other contracts have a surcharge in the form of paying an amount per kWh consumed. The surcharge in the two types of agreements is not directly comparable. One measure that both Oslo Economics and Renewable Norway recommend is guidelines for information on effective surcharges that can be compared across agreements. A complicating factor is that the calculation of the effective mark-up will depend on the size of consumption. It must therefore be possible to provide information on the effective mark-up for different levels of consumption.

Information about price hedging

To improve the market for fixed price agreements and price hedging, there are several types of information measures that can be implemented, both about market development and the agreements themselves:

- *Information about the electricity market going forward - expected development in price variation*
  Customers have varying degrees of access to information about developments in the electricity market today. If customers expect the market to return to historically normal price variation, while the variation instead increases, this may lead to customers not making the adjustments in the market that would be best for them. More information about the electricity market and expected developments can enable customers to make better choices about which electricity contract they want.

- *Information about the types of fixed price agreements offered and what a fixed price agreement is*
  Consumer Council's current recommendation is that spot price agreements provide the lowest cost over time, but that fixed price agreements are an alternative if you want predictability. Most household customers have no experience with fixed-price contracts and little basis on which to base their judgement. More and better information to customers about different types of fixed-price agreements and what these do compared to a spot price agreement can improve the market.

- *Fixed price agreements with fixed volume - partial price hedging*
  One of the barriers to entering into a fixed price agreement can be the price level. The customer pays a premium for the supplier to assume the risk that the spot price level is higher than the level in the fixed price agreement. The size of the premium required to cover the supplier's risk has been highlighted as one of the barriers for suppliers in the market.

  If partial price hedging is an option for the customer, it may be possible to enter into a fixed price agreement for a fixed agreed volume. The
  customer must then be responsible for the cost of the electricity supplier buying electricity in the spot market if the customer uses more electricity than agreed in the agreement, and also the difference between the price in the agreement and the spot market if the customer uses less than the agreed volume. In this way, the volume risk can be transferred to the customer. The result is that the electricity supplier's costs are lower and that surcharges can be set

lower, while the customer has to live with the fact that there is no fixed price for the entire consumption, as is common for household customers today.

One barrier to such agreements is that the price in the fixed price agreement is not the actual electricity price per hour for the customer. The spot price used for over or under consumption will vary. The agreement provides a greater degree of price hedging than a spot price agreement, but not complete price hedging for the entire consumption. This makes it more difficult for the customer to compare with a fixed price agreement on variable volume. Offers of fixed price agreements with a fixed volume should therefore be accompanied by good information so that the customer has the opportunity to assess the total cost of the agreement against their own consumption and, for example, a range for the spot price level during the period of the agreement.

16.4.1.2 Framework conditions

General

- *Enforcement of regulations and sanctions*
  Renewable Norway and several others have highlighted the need for tougher sanctions against electricity suppliers and the possibility of withdrawing a sales licence in the event of a breach of the legislation. Some have advocated raising the threshold for obtaining a sales licence. Oslo Economics also emphasises the need for stronger enforcement of current regulations, particularly compliance with the requirements of the Marketing Control Act and other consumer protection provisions.
- On behalf of the MPE, RME has assessed sanction options for electricity suppliers, and submitted an assessment in June 2023, in which they propose, among other things, the possibility of withdrawing licences in the event of breaches of legislation other than the Energy Act. Follow-up of the proposals for clarification of the regulations and increased sanction options are measures that can improve the market.
- To enable enforcement of the regulations, one measure could be increased access to documentation of the contracting process, such as recordings of telephone sales calls, in order to be able to verify what information is provided in the calls.

Price hedging

- *Measures to increase liquidity in the financial market and the possibility of price hedging for electricity suppliers The*
  future market for electricity is a key framework condition for electricity suppliers to be able to offer fixed price agreements. As described in chapter 8 lack of liquidity and the high risk of providing collateral is a barrier for electricity suppliers to offer such agreements. *In* addition, the future market is changing, cf. chapter 6.1.3. Measures to improve liquidity and increase access for electricity suppliers to be able to hedge their prices in the future market therefore appear to be important for electricity suppliers to be able to provide an adequate supply of fixed-price agreements with favourable terms in the future.
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  Several electricity suppliers have offered customers electricity contracts where the customer's payment is equalised throughout the year. At any given time, the customer has an outstanding balance where they either have money owed (typically in the summer when prices are low) or outstanding (typically in the winter when prices are higher). This type of arrangement can apply to both spot price agreements and variable price agreements. As described in chapter 8 RME has criticised the scheme, as it has a low degree of transparency and in practice functions as a consumer loan. RME has required a number of suppliers to discontinue their offerings. The industry itself points out that this is actually an opportunity for customers to pay spot prices while at the same time receiving predictable payments.

Such agreements do not involve price hedging in the sense that the price is agreed for a period in the future, but are intended to ensure the customer a certain predictability for their total costs. One possible measure to improve the market for customers who want predictability is to look at whether the fixed payment scheme can be improved so that it has a greater degree of transparency and is within the regulations, possibly an adjusted set of regulations. A well-functioning scheme could be an opportunity for customers to have both spot price exposure and thus incentives to react to the price level, while at the same time gaining predictability around monthly costs.

- *Permanent resource rent tax exemption for fixed price agreements*
  In 2023, as described in chapter 8 a temporary exemption was introduced when calculating resource rent tax for 2023 and 2024 for power producers' sales of fixed-price contracts to businesses, where the producers are taxed at the contract price, not the spot price. Such an exemption facilitates a broader offer of fixed-price contracts to businesses and more use of long-term contracts in businesses beyond the power-intensive industry. So far, the market is developing, both on the supply and demand side, with a relatively limited supply of products in the early stages of the market. It is possible that more products, increased volume offered and also increased demand for this type of fixed price agreement will come as the players gain experience and the market develops. The Government will consider extending the exemption beyond 2024. Continuation may facilitate more use of long-term price hedging in the business sector in the long term. In the long term, the scheme may also be considered for extension to households.

- *Expansion of EKSFIN's guarantee programme*
  The scheme currently covers industrial companies with activities within wood processing, metal production and production of chemical products, cf. chapter 8.6.4. The scheme covers 80 per cent of outstanding financial obligations. Power buyers can purchase guarantees for the fulfilment of terms in power contracts. The guarantees are entered into with power buyers, or a consortium of power buyers, with a minimum of 10 GWh annual consumption and a minimum of 35 GWh consumption over the lifetime of the contract. The guarantees mean that power sellers, and banks or other lenders, can reduce their risk premium and thus the costs for power buyers by entering into such guarantees. The current scheme is not utilised to any great extent. According to figures from EKSFIN, utilisation of the framework in the scheme over the past four years has been between 20 and 25 per cent, and the scheme has received three applications, two in 2019 and one in 2021.

  One possible measure is to expand the scheme to cover more industries and companies. This would enable more companies to enter into long-term contracts. This provides more predictable prices for companies and can help to increase demand for fixed-price contracts. Another measure is to reduce the requirements for who can enter into the contracts, for example reducing the requirement from 10 GWh annual consumption to 1 GWh. However, given that interest in the scheme now appears to be low, the need for such an expansion and what can be done to improve utilisation of the scheme must be assessed in more detail.

- *PPA co-operatives*
  One way of facilitating a larger proportion of end users to enter into long-term contracts is to bring together a number of businesses or households in a co-operative. The co-operative

then enters into negotiations directly with electricity suppliers or with producers in line with power-intensive industry. Purchasing large volumes in the electricity market does not necessarily result in lower prices, since the alternative value for producers is the expected future market price. However, there may be an opportunity to enter into agreements over a longer time horizon than the future market can offer today. In return, the co-operative will have costs to cover.

Such a measure must probably mean that PPA co-operatives are also covered by a basic rate of return tax exemption for fixed price agreements, as is currently the case for power-intensive industry, cf. the point above. The design of the agreements will also be important to ensure that end users still have some spot price exposure and can react to price signals (adapt consumption).

A form of cooperative incentive was created in 2009, when the authorities established a support scheme for power-intensive companies that entered into a consortium for the joint purchase of power. This scheme was never utilised, which indicates that the design of a new arrangement for PPA cooperatives may need to be carefully considered. The organisation of fixed price agreements directly from the producers in the new resource rent tax exemption (see the discussion of the resource rent tax exemption above) could meet many of the same needs as a PPA cooperative.

16.4.2 Regulation of the market

16.4.2.1 Order to offer fixed price agreements

One way of regulating the market for price hedging and raising awareness of price hedging alternatives could be to require electricity suppliers to offer fixed price agreements to customers. In the EU's revision of the regulations for electricity market design, an obligation to offer fixed price agreements is also proposed as a requirement for electricity suppliers, see a more detailed description of the EU's electricity market reform in chapter 11.

An offer of a fixed price agreement can be designed in different ways, but the main point must be that information about a fixed price agreement is communicated together with information about a spot price agreement so that the customer decides which type of agreement they want.

With a mandatory offer, customers will receive clearer information about fixed price agreements and to a greater extent have to decide whether they want such an agreement. This may enable the customer to make a better choice between the two types of agreement and increase demand for fixed price.

For their part, electricity suppliers are required to offer contracts. Normally, there are no obstacles for electricity suppliers who wish to offer such agreements. However, smaller players may wish to offer spot price agreements, since offering fixed price agreements involves a different business model where you have to take risks in the future market for electricity. This requires capital to collateralise the positions and places other demands on internal risk management. An obligation may therefore mean that some suppliers are no longer able or willing to participate in the retail market.

In the current situation with high risk and difficulties in price hedging in the future market, a mandatory offer will mean that some electricity suppliers who normally offer such agreements will have to offer agreements that they cannot adequately price hedge. This entails a risk that suppliers will have to price into the contracts. This can make the contracts very expensive. Another basis for fixed price agreements may be the sale of price hedging by the producers, similar to the agreements that were created as a result of the temporary basic rate tax exemption for fixed price agreements (discussed above).

Assessment - will the market function better and will the measure contribute to more predictable prices?

- Low volume in the fixed-price market appears to be a consequence of a lack of demand, not a lack of supply, and it seems likely that more and better information can increase demand. The offer of a fixed price agreement can contribute to better information so that this appears to be a real alternative for more electricity customers.

- However, it is not clear that a requirement for fixed price agreements will have a better effect than pure information measures. Information about fixed-price agreements and the electricity market must be provided in any case in order to increase demand to a significant extent, even with mandatory supply.

- Direct regulation of the suppliers' supply can have negative consequences for supply, as suppliers who only offer spot prices have to withdraw, or suppliers of fixed prices have to take on risks that have a cost-increasing effect in the market.

The Commission assumes that facilitating increased use of fixed price agreements will not conflict with Norway's obligations under the EEA Agreement. The right to require market participants to offer fixed price agreements is limited in principle, but as mentioned above, the EU's new power market reform envisages an obligation for electricity suppliers above a certain size to offer fixed price agreements. This indicates that the authorisation to do this under EU/EEA legislation may be greater.

However, high-quality information that is of great benefit to electricity customers is not self-evident and will probably require a lot from both the industry itself and various regulatory bodies.

16.4.2.2 Prohibition of different types of agreements

The ban on agreement types has been most discussed for standard variable price agreements, which is a type of short-term fixed price agreement. As with other fixed price agreements, the electricity price is set by the electricity supplier, including surcharges, but for a short period, in practice 30 days. These agreements have been criticised for lacking transparency, having a low degree of security and higher prices than other agreements. In its report on measures in the retail market, Oslo Economics (2023) points out that it has historically been a problem that customers do not understand the product and pay for price protection that they do not benefit from. The Consumer Council advises against such agreements and has asked electricity suppliers to cut sales and the authorities to ban this type of agreement. Statistics Norway shows that variable price agreements are on average the most expensive form of agreement on the market.

One important reason why the contracts appear expensive is that electricity suppliers cannot easily price-hedge the risk they take on during the 30-day period. 30 days is so long that a lot can happen to wholesale prices. Suppliers must take this risk into account if they are to offer this type of agreement.

Oslo Economics points out that, in general, a reduction in the number of contract types offered can have beneficial effects by making the market more transparent. If agreements that several end users do not understand are removed from the market, a ban will reduce the number of end users with an agreement that they do not know the consequences of. At the same time, a ban on standard variable contracts will limit the opportunities for suppliers to engage in product differentiation and may limit innovation and product development. Oslo Economics believes that for a ban to be considered the most appropriate solution, there should be clear negative effects that cannot be avoided by less invasive means.

The EEA Agreement does not preclude a national prohibition against specific elements of electricity contracts as long as the prohibition contributes to a high degree of consumer protection without restricting competition between suppliers and does not deprive electricity customers of a real freedom of choice between different types of electricity contracts. Any prohibition must be assessed specifically in light of the impact the prohibition will have on consumers' overall freedom of choice and the benefits the prohibition will provide for consumers. There is little concrete guidance on where the boundary between a legal and an illegal national ban lies, and such a measure will therefore be associated with a certain risk.

In Norway, the market has been characterised by many customers having variable prices. At the end of 2021, the proportion of customers with this type of agreement was around 20 per cent. The share fell significantly throughout 2022, and was 4.2 per cent in the second quarter of 2023. In November 2022, section 22, fifth paragraph of the Price Information Regulation was amended so that the electricity supplier must notify the customer of all changes to or termination of agreements, including price changes with the exception of spot price changes, no later than 30 days before the change or termination is to take effect. Prior to the regulatory change, the deadline was 14 days. These changes increased the complexity of the standard variable contracts, also from the supplier side. There have also been information initiatives to inform customers about the agreements. This has led to the offer of the contracts largely being cancelled, and suppliers have actively encouraged customers to switch contracts. However, as the statistics show, there are several customers who still have such agreements. In its report on measures in the retail market, Oslo Economics states that it is reasonable to assume that a proportion of customers have chosen this type of agreement because they want such a price protection agreement, but it is likely that a number of customers who have this agreement have had it for a number of years without it being a conscious choice. There is no overview of the types of consumers who still have these agreements. There is a risk that a proportion of the customers who remain in these agreements are among the most vulnerable in the market. Because of this risk, the Committee believes that, in the interests of consumer protection, measures should be investigated to ensure that vulnerable customers do not remain in variable-price contracts that are unfavourable to them. Such measures must be assessed in relation to current and possibly future obligations under the Third and Fourth Electricity Market Directives.

16.4.2.3 Obligation to offer standardised contract types

The requirement to deliver a standardised agreement, either spot price agreements or fixed price agreements, can make agreements more easily comparable for customers, provided that the specification is at a level of detail that makes the comparison meaningful.

However, it will be difficult to specify a type of agreement that meets the needs of the market. If it appears to be a recommendation to enter into standardised agreements, this may in the long term have a negative impact on product development and on the business of suppliers offering more specified products.

16.4.2.4 Limitation of maximum surcharge to electricity suppliers

Measures aimed at addressing market failures in the retail market could contribute to lower prices as a more efficient market will reduce the mark-up for electricity suppliers and thus lower costs for customers. An alternative to market improvement is to regulate the maximum mark-up electricity suppliers can charge. This would mean that the most expensive contracts would no longer be offered, and the customer would be protected against a high surcharge when entering into the contract and in the event of subsequent changes to the contract.

On the other hand, a maximum mark-up can become self-fulfilling, so that suppliers set the mark-up equal to the maximum mark-up. The competition literature is full of examples of maximum price becoming an anchor point for market prices. Regulating the mark-up also makes the market less efficient and can weaken competition in the market, leading to higher costs in the long term.

16.4.2.5 Ban on advance invoicing

Some electricity contracts have a payment on account, where the customer pays an estimated price for a given period in advance, and then the payment is settled against the actual price and consumption when the period is over, and the electricity customer receives a refund or must pay money to cover the difference.

A ban on prepayment can help to make the market more transparent, and customers avoid the risk of losing the amount paid if the supplier goes bankrupt. At the same time, it can prevent new suppliers from establishing themselves by having to finance purchases before they receive payment from customers. The risk of customers losing money can be mitigated by other measures, such as specific requirements for guarantees in the supplier's licence.

16.4.2.6 Prohibition on price changes after conclusion of the contract

Some electricity suppliers have been criticised for changing the price shortly after the customer has signed a contract. Customers are free to switch contracts if there is no binding period agreed, but there is a risk that the customer does not realise that the price change is taking place. A ban on price changes for a certain period will counteract this.

The new Price Disclosure Regulation requires that the duration of the price in the agreement must be stated. It may therefore be that this need is already adequately covered by the current regulations. It may be difficult to define an appropriate period for a ban. It will also entail great risk for suppliers if the prohibition applies not only to the mark-up, but to the total price.

16.4.2.7 Restrictions on lock-in period and cancellation fees

Some agreements have a lock-in period and an associated fee if the agreement is cancelled by the customer. The same is known from the market for fixed-rate mortgages. This can be challenging if the customer does not realise the consequences of the agreement and how expensive it will be compared with alternatives, especially in cases where the price in the agreement is set for a period of time in the future. A limit on the lock-in period and cancellation fee can therefore limit the risk for the customer by remaining in an agreement.

The breakage fee is set to manage risk on the electricity supplier's side. In order for the supplier to be able to deliver a fixed price over time, the supplier must secure the volume they sell, and a lower volume sold to the end customer represents a risk. If this risk is not priced into a breakage fee in the contract, the supplier will either not be able to deliver such contracts, or pass on the risk premium in the price of the contract. Customers who wish to have long-term contracts will then receive a poorer offer.

16.4.2.8 Marketing initiatives

In addition to regulatory requirements related to products, Oslo Economics has also assessed different types of marketing measures. In addition to increased information, as discussed above, they have assessed:

- Prohibition of bundling (selling electricity together with another product)
- Prohibition on the sale of electricity contracts by telephone, door-to-door or stand sales
- Prohibition against winback (marketing towards customers who want to terminate a contract)

What these have in common is that they can make the market more transparent for customers and prevent them from entering into agreements that they do not understand the content of or cannot compare with other agreements.

The downside is that bans can limit variation in supply and competition in the market, and can prevent, for example, bundled sales that incentivise electricity savings through electricity contracts with smart control systems. Alternative measures include information requirements to ensure that customers have a good basis for decision-making in the sales situation.

16.5 Measures for increased government control of the market

The current model for the retail market is based on competition between suppliers and free choice of electricity supplier for customers. One way of dealing with market failure in the retail market may be to manage the market directly instead of maintaining the current model with competition. This type of measure will typically involve organisations that regulate the supplier level and/or the products offered. The Norwegian market currently has a high degree of competition. Reorganising the market will not typically lead to more competition, but will be a means of making the market more "manageable" for customers by increasing the degree of regulation. This requires more government-organised monitoring of the market, and a government player must take full or partial responsibility for both delivery and product development.

16.5.1 State organisation of the supply chain

Today, customers in the retail market can choose between a number of different products and suppliers. An alternative organisation of this market could be to phase out the electricity supplier companies through direct regulation and appoint others to take care of purchasing, balance responsibility, product development, customer follow-up, etc. In this way, customers would not have to deal with choosing a supplier, thereby reducing the risk in the market of making the "wrong" choice.

The operation of the electricity supply service can either be financed by customers paying for the service as a surcharge, as in the current system, or via the national budget and thus financed by tax revenues.

In such a system, the type of agreements and additional services offered by a government-appointed supplier must be fully or partially regulated. On the one hand, the authorities may wish to regulate the type of contracts that customers should be offered. On the other hand, the supply side may need to be regulated to maintain a diversified offer unless the designated supplier(s) are incentivised to develop offers and products in the same way as in a competitive market.

With this organisation, customers will not make a choice of electricity supplier. If the state-regulated service offers different contracts and services, they will still make choices between these, such as a choice between a spot price contract and a fixed price contract, or a choice of additional services, such as automatic electric car charging or other services that regulate consumption.

Assessment - is the market becoming more efficient?

- The measure can increase transparency for customers. Effective regulation reduces the risk of paying too high a surcharge due to a lack of insight into different agreements. The measure can also increase confidence in the electricity supply service by having a state-owned player delivering the service, thereby reducing the risk that the supplier has incentives to capitalise on information asymmetry.
- The cost of providing the service may be higher or lower than the current situation. In the case of state provision and a monopoly on the service, the mark-up must be regulated. Given that the regulated mark-up reflects the actual operating costs for the supplier, the mark-up

may be lower if the market failure is so significant that the current level is generally higher than the market-efficient solution. However, the cost may be higher because the supplier does not necessarily have the same incentives to operate efficiently.

- Whether designated suppliers have stronger or weaker incentives to develop offers in line with demand depends on the regulation of the activity. There is a risk that, over time, the supply of agreements and products could be poorer compared with a well-functioning market solution.
- More state-regulated offerings may possibly alleviate the risk for passive customers, if the offering is limited so that there are not so many choices. This may be less costly for passive customers or customers who do not want to be active in the market, as the risk of making the "wrong" choice may be reduced. However, it is an open question as to whether designated suppliers reach electricity customers with their offers.
- The negative effects of the measure will be mitigated if the state-appointed supplier does not have the entire market, but only part of it and, for example, is only organised as an offer for certain customer groups.

Given that the public operator operates on market terms, such a measure will be lawful under the EEA Agreement. Hjelmeng writes in his memorandum (page 5): *Although the public sector is free under the EEA Agreement to conduct its own activities in a market, the so-called market participant principle sets up a framework for such activities. In principle, the public sector will not be able to enter into projects in the market that would not also be relevant for a rational private investor, i.e. operations must have the prospect of making a profit* (Hjelmeng 2023).

Interventions that affect the activities of private electricity suppliers must be assessed against current and any future obligations under the Third and Fourth Electricity Market Directives.

16.5.2 Price regulation

16.5.2.1 Authorisation regulated fixed price

Some countries have had a system where the price in the retail market is set for a period of time at a time. In the UK, the regulator sets the price to end users for a three-month period based on the expected market price. Such a system would not initially be designed as a support programme, since the price follows the market level. However, customers will have predictability in their electricity costs for a given period at a time. In practice, this is a government-regulated fixed price agreement on market terms.

The outcome of the system will depend on whether other suppliers and agreements are opened up in addition to the government-regulated fixed price. If the regulated fixed price is the only offer, customers will not choose another agreement and the electricity supplier stage will largely be a resale of a given price. It may be possible to maintain additional services that customers can choose from, so that there is still a market where you can choose different suppliers, but given that it is not possible to compete for different types of electricity contracts, it is reasonable to assume that there will be a significantly lower number of suppliers. If there are very few suppliers in the market and there is a form of monopoly situation, the supplier level may need to be regulated.

Customers will to a small extent relate to the market itself, and the strategy for price hedging and product selection is largely decided. This provides increased predictability and less risk of the customer making the 'wrong' choice.

In the UK, this has worked in such a way that the government-regulated price acts as a reference price, and suppliers compete to deliver contracts that are below this fixed contract price, see chapter 8.11. In practice, the government-regulated price becomes a price ceiling. This means that it is still largely possible to maintain competition at the supplier level. As long as the price in the regulated contracts is market-based, it is possible for other market players to compete against this contract.

If the price is the same for all hours in the given period, customers generally have less incentive to adapt to high-price hours, as with increased use of price hedging. However, since the price is regularly adjusted according to market prices, customers will be exposed to high price periods that last for some time, which means that they will have incentives to reduce consumption during these periods.

Such an organisation of the market in Norway will require legislative changes and an assessment against the EEA Agreement to ensure that the agreements cannot contain elements of state aid.

It will also be necessary to decide whether electricity suppliers who offer the regulated agreement should price-secure the volume for the agreements themselves, or whether this should be done in some other way.

Assessment - is the market becoming more efficient?

- If only the government-set fixed price is offered, the market will be easier to manage as customers will have fewer choices and greater predictability of costs for a given period at a time. As with a state-owned electricity supplier, such an organisation could lead to more trust in the market since the price is regulated.
- Less supply and fewer suppliers means a more limited market and thus a greater risk of inefficiency, weaker incentives for suppliers to develop new products and higher costs for customers in the long run.
- If everyone has to buy contracts with a regulated price, this will in practice mean a limited offer to customers. Customers who want spot price agreements or fixed price agreements for longer periods will not necessarily receive an offer.
- If a regulated price agreement does not apply to all customers, but competes with other agreements in the market, the negative effects of regulation may be reduced. It must then be considered what will be achieved with a state-regulated offer. On the one hand, operators with low confidence in the market and/or passive customers may have more confidence in a state-regulated offer. On the other hand, it is not certain that this offer is actually the best solution for these customers.
- The price set by the authorities can become a reference price in the market. This can be simplified and transparent for customers. On the other hand, it can limit competition in the market.

16.5.2.2 State-owned retailer of electricity for fixed-price contracts

The current system for price hedging is offered by electricity suppliers, who normally hedge their electricity purchases in the future market and deliver to businesses and households, and by power producers, who have entered into bilateral agreements with power-intensive industry. In the new fixed price agreements for businesses, the electricity suppliers resell offers of fixed price agreements from the power producers.

The measure described here involves a state-owned operator, or a state-appointed operator, negotiating with power producers on the purchase of electricity so that the electricity suppliers can resell this volume. The reference price for all types of fixed price agreements is the expected future market price. A desired outcome of a state-owned operator negotiating directly with power producers is that the purchase of a larger volume of electricity could lead to lower prices than the electricity suppliers could have achieved on their own.

For customers who want fixed-price agreements, the measure will not result in changes, but if the offer of fixed-price agreements is improved or becomes cheaper, the measure may lead to increased use of fixed-price agreements.

The role of electricity suppliers will depend on the market as a whole. Given that spot price agreements will be the responsibility of the suppliers, there will still be a basis for a competitive market among electricity suppliers. Electricity suppliers will also have an alternative to hedge electricity costs in the future market by offering fixed price agreements. This means that suppliers can avoid the current barriers to offering fixed price agreements in the form of a lack of hedging opportunities in the future market.

For power producers, it may be attractive to move price hedging from the financial market to negotiated purchase agreements. The terms on which power producers will sell electricity will depend on a number of factors. Today, long-term purchase agreements are encouraged by a basic rate tax exemption that means that the producer is taxed at the contract price for certain types of electricity sales. If a similar exemption is not introduced for this type of sale, the tax risk for producers will be priced into the agreements and make them more expensive than other fixed price agreements.

In any case, power producers will have an alternative market for long-term power sales (the forward market), where the assessment of value is based on future price expectations. Generators generally have no incentive to sell electricity at a lower value than the price expectations in the market. The situation is different if the producers lack other ways to hedge their prices and have a willingness to pay for this type of sale. There is nothing that currently indicates that the producers lack this type of opportunity.

Large purchases can also have the opposite effect - it can have a price-driving effect if producers do not see it as economically favourable to lock in larger volumes with contract types that are difficult to combine with normal forward contracts. In this case, the result may be a premium on top of the prices in the futures market for entering into an agreement. This is a normal feature of all commodity markets and securities markets: if someone wants to buy a single share in a listed company, it normally has no impact on the market value of the share. If, on the other hand, someone wants to buy, for example, half of all the shares in a company, the market value will typically increase when this becomes known.[61] The same applies to forward contracts in the wholesale power market. If it becomes known that a large buyer wants to hedge a large volume, those who are to carry out the assignment will try to conceal the size in order to prevent the price from rising as a consequence of the large buying interest.

If a state-owned company acts as a market player in line with other players, such a measure is unlikely to pose any challenges under EEA law, but a specific assessment must be made. Among other things, the measure must be assessed against current and any future obligations under the Third and Fourth Electricity Market Directives.

Assessment - is the market becoming more efficient?

- Government procurement for fixed price agreements can increase the supply of fixed price agreements to electricity suppliers.
- An arrangement whereby power producers sell electricity on long-term contracts to electricity suppliers may also be an alternative to suppliers hedging the volume in the futures

[61] This is an important reason why, for example in the stock market, there are rules on reporting requirements for players who acquire an ownership interest in a limited company.

market. This could facilitate increased supply, especially in light of the difficulties in the futures market over the past year.

- A government negotiator can help improve information asymmetry about fixed price agreements and greater confidence that the price level is set correctly, thereby also leading to increased demand.
- A lower price level for the underlying electricity price to customers cannot be expected than under the current system, since the reference value for the sale of electricity in the future is measured against long-term price expectations. However, the producers' price hedging strategies may move the price level both up and down. Large purchases from the state can also potentially have a price-driving effect in itself.
- Increased use of price hedging through bilateral agreements will have negative consequences for the financial market. If large volumes are transferred to bilateral long-term contracts, there will be lower volumes in the futures market. This could lead to less confidence in the futures market as a relevant price, and thus increased risk and risk premiums that will affect the price in fixed-price contracts.

16.5.2.3 Continuation of differential contract pricing to consumers

A combined measure for both price protection and subsidising new renewable energy could be for the government to pass on the price in contracts for difference to electricity customers. Difference contracts are a support system for renewable electricity production, where the government guarantees a given price level. The producer is then paid the difference if the spot price level is below the contract price, and may have to pay the difference if the spot price level is above the contract price.

If the price in the difference contract is passed on to customers[62] , customers will implicitly help to finance new production. Since this price is fixed and does not fluctuate with the spot price level, this will in practice be a form of fixed price contract and entail a greater degree of price hedging for customers. This could be a form of mandatory price hedging, if all customers are to be covered. It is possible to envisage exceptions to this obligation, cf. the fact that power-intensive industry is exempt from the obligation to purchase electricity certificates.

It is likely that the price in the difference contracts will be higher than the market price, since the basis for creating a difference contract is that the project to be financed is unprofitable with current price expectations. The current spot price level varies and will probably be above and below the contract price in periods. However, there is considerable uncertainty about future price developments. Even if the price expectation when entering into a contract for difference is that the contract price is above the market price on average, it is not certain that this price difference will be the net effect over a long period of time. The total cost for the electricity customer may therefore end up above or below what could have been achieved with price hedging based on market prices.

It is highly uncertain what the volume of difference contracts may be in Norway, but in any case it will only be able to cover a proportion of all electricity consumption. As of now, the authorities have announced contracts for offshore wind production in the Southern North Sea II. Much of the electricity consumption must therefore be covered by other types of contracts. In principle, consumers can do this themselves at market prices. If the state were to offer the remaining level of contracts to consumers, they would have to purchase power in the market on market terms. As described in the assessment above that a state supplier and state purchaser of power will not automatically result in lower costs for customers, the result may be the opposite. If there are other

[62] The use of revenue from contracts for difference as support for consumers isdiscussed in Chapter 17.

well-functioning alternatives for price hedging in the market, this would be a better alternative than the state purchasing power and reselling it.

Assessment - is the market becoming more efficient?

- With mandatory price hedging, customers will have greater predictability and will have to make fewer choices in the market. This can simplify the situation for customers and make the market more transparent.
- On the other hand, customers who do not want price protection will be deprived of the choice to do so in whole or in part.
- Continuation of prices in contracts for difference can drive up costs for customers. The measure can primarily be perceived as a user financing of new electricity production and in this case also price hedging for customers, not a measure for lower prices in isolation. Even if new production leads to a stronger power balance has a price-damping effect, it is uncertain whether the net effect of the measure for customers will be a price increase or a price reduction.
- If there is otherwise no market offer of price hedging, government-based solutions for price hedging will be a way of ensuring customers such an offer. There are no obvious advantages of the state entering the supplier side if other alternatives exist in the market.

16.6 Consumer flexibility in peak load hours

The committee's mandate specifically mentions consumer flexibility during peak load hours. Peak load hours are hours when the total consumption of electricity is at its highest. Such hours can pose challenges for the power situation in the system. Power is the amount of electricity that can be used at one time. In physics, it refers to energy per unit of time, and in the power market this is normally concretised as energy per hour (or quarter of an hour). Even if the production capacity of the Norwegian system over a year is sufficient to cover consumption, there may be very high demand for power during individual hours, for example due to cold weather and low imports. The amount of power that can be produced and transmitted to customers in individual hours, i.e. power output, is limited by the capacity of the production facilities and grid capacity. If there is not enough power capacity in the system, this will lead to poor security of supply because the supply of power does not match demand.

With more fluctuating prices, increased consumption and an increased degree of unregulated power production, it is likely that power issues will become more important in the future. NVE's analyses of the power situation show that although there is sufficient power in the system today, this will be challenged in a 2030 perspective (NVE 2022). During hours of high demand, it is not only power that can be challenging, but the price level can also be very high. Measures to increase flexibility during peak load hours can therefore alleviate power problems and help to mitigate price peaks in addition to reducing the need for increased grid investments, which in turn helps to counteract increased grid tariffs for customers.

There are several sources of flexibility during peak load hours, mainly consumer flexibility, production flexibility and power imports. In addition, several specific measures to mitigate energy demand during peak load hours will also reduce energy demand for the year as a whole. Here we look at consumer flexibility specifically, for both households and businesses.

16.6.1 How can consumer flexibility be realised and what is the potential?

Several long-term analyses, such as Statnett's long-term market analysis, use the assumption that production of green hydrogen will result in significant consumption flexibility in the system. There is little production of green hydrogen at present, and it is uncertain when production will be scaled up so that it can make a significant contribution to flexibility in the system. Statnett assumes that this will happen in the 2030s. In the short term, other sources will therefore have to contribute to consumer flexibility.

The most important instrument for triggering flexibility is that the price signals from the wholesale market reach the customers. During peak load hours, the price will be high, and this in itself gives customers incentives to reduce consumption. Elsewhere in the report, it is discussed that electricity subsidies and price hedging give customers weaker incentives to adapt to the price level, and this also applies to consumption flexibility during peak load hours. Measures that remove all price signals for customers remove much of the market incentives to trigger consumption flexibility.

In order for customers to be able to respond to price signals, they must have the physical ability to reduce consumption. Some consumption is in any case difficult to shift in time or reduce temporarily, such as consumption in power-intensive industry, where continuous access to electricity to maintain production is of high value. Here, the cost of reducing consumption will often be higher than paying the high prices and thus being able to maintain production. Other types of industry may have greater opportunity to shift production and thus electricity consumption to less busy hours. However, agreements with customers waiting for products or services may reduce flexibility in practice. For businesses and households where much of the electricity consumption is related to heating and operation of buildings and transport, there are generally good opportunities to reduce or shift consumption in time, without reducing comfort. However, there may be barriers in the form of the fact that not all customers relate to the market hour by hour, and these may be more dependent on automation solutions for consumption adapted to price levels in order to utilise the flexibility.

The largest volumes of flexibility per individual installation are also the most difficult to realise. It is possible to trigger large volumes of flexibility for large customers such as power-intensive industry, but due to price-inelastic consumption patterns, flexibility requires large investments and also new technology. Flexibility in buildings will trigger a smaller volume per individual unit, but at the same time has lower costs and the opportunity to implement such solutions, so that the sum of customer flexibility in buildings can be large.

THEMA and Multiconsult (2022) illustrate the potential and cost level for consumer flexibility in different sectors as follows:

Kilde	Mulig volum 2030 (MW)	Mulig volum 2050 (MW)	Kostnad	Type tiltak	Ledetid	Forutsetning for å levere
Effektutvidelser vannkraft	700	Potensielt stort	Middels	Få og store i		• Lønnsomhet • Konsesjon og konsesjonvilkår
Pumpekraft	-	-	Middels	Få og store investeringer		• Lønnsomhet • Konsesjoner
Reservekraft	280	Tilpasset behovet	Svært høy	Få og store investeringer		• Kapasitetsmarked i regi av Statnett
Tradisjonell industri	3500	3500	100-200 EUR/MWh	Utnytte eksisterende		• Lønnsomhet pga. prisvariasjoner • Lav risiko for produksjonskjeden
Batterifabrikker	250	avh. av utbredelse	Middels	Få og store		• Lønnsomt med termisk lager eller alternativ energi
eFuels	usikkert	1000	Lav	Styring		• Lønnsomhet - prisvariasjon over døgnet
Bygg	1000	6000	Middels-høy	Mange og små		• Lønnsomhet og kunnskap om tiltak • Automatisk styring og enkel data tilgang
Hybrid transport	75	100	Lav	utnytte eksisterende kapasitet		• Lønnsomhet • God tilgang på alternativ drivstoff
Batterier	Ukjent, men økende	Stort, inkl V2G	Høy, men synkende	Mange og små		• Lønnsomhet - brukes til flere formål

Figure 16- 1 Potential and cost level for consumer flexibility

16.6.2 Measures for increased consumer flexibility during peak load hours

Measures to increase consumer flexibility may be relevant to consider if price signals and other available flexibility in the system are not sufficient to remedy the situation during peak load hours. If there is little flexibility in consumption and high costs for customers, the socio-economic value of flexibility in the system may nevertheless exceed the value of reducing consumption for individual customers. Even at very high prices, it is possible that customers' willingness to pay to maintain electricity consumption during peak load hours is even higher. In this case, various measures may be relevant to release flexibility that the market does not provide itself:

- *Legally required flexibility, for* example in authorisations to connect consumption to the grid, can be effective measures. At the same time, requirements have potential costs for customers who do not necessarily have profitable measures they can take to make their consumption more flexible. Requirements may reduce the commercial profitability of business activities. Statutory requirements should therefore possibly be targeted at consumption where the potential for flexible consumption is present without major net costs for the customer.
- *Agreements on flexibility* can be made through support programmes where the customer is paid to reduce their consumption, thereby making the value of consumption reduction for the customer the same as for the system as a whole. In theory, this can be aimed at both small and large consumers of electricity. Statnett's energy options in consumption (section 15.4.1) are an example of such agreements, even though they are aimed more at energy shortages than at peak load hours.

The effect on prices in the wholesale market of using energy options on the consumption side is analysed in chapter 15.

17 Power support

Chapter 17 deals with measures that reduce the customer's electricity bills to a level below wholesale prices. The purpose of such measures will be to shield the customer from the effects of high electricity prices and help to manage costs, whether for households, businesses or other consumer groups. For example, support for households may be motivated by protecting consumers who unexpectedly find themselves in a vulnerable financial situation. Support for businesses may be motivated by maintaining activity and supply, and protecting their competitiveness.

This chapter assesses various proposals for measures aimed at the retail market that aim to reduce consumers' electricity bills to a level that is lower than the spot price, and which may therefore contain elements of public support. If electricity bills are to be reduced without interfering with price formation in the wholesale market, the difference between the lower retail price and the higher spot price must be covered by resources obtained by means other than the consumer's bill. An electricity supplier that is required to sell electricity at a price that is lower than the company's purchase price in the wholesale market will go bankrupt without a subsidy. The measures therefore require a direct or indirect transfer of resources to consumers that the market itself will not provide, and which must therefore be politically determined. The electricity subsidy programmes introduced during the electricity price crisis in 2021 are examples of a politically determined transfer of resources to consumers, with the aim of curbing electricity bills. The chapter assesses various electricity subsidy schemes and other mechanisms where resources are transferred to consumers to mitigate their costs.

The measures assessed in this chapter differ from those assessed in chapter 15 and 16. In chapter 16 measures aimed at the retail market that aim to correct market failures and facilitate price hedging agreements, but which do not result in retail prices that are lower than wholesale prices in the long term and which do not contain elements of public support, are assessed. In chapter 15 measures aimed at the wholesale market are assessed.

The committee does not take a position on how support programmes should be financed or the size of any redistribution. The existing electricity subsidy scheme is partly justified by the fact that public revenues increase when electricity prices are high, which is why the Norwegian electricity subsidy scheme has been referred to as redistribution. Revenue distribution can be handled in various ways, through direct transfers in subsidy schemes, indirect transfers in other schemes, or in other ways via the national budget or the tax system.

Support to manage increased electricity costs can also be provided in ways other than reducing electricity bills. In Norway, little use has previously been made of schemes that directly subsidise consumers during periods of high prices. Increased government revenue has instead been channelled into increased welfare. Subsidies can also be provided through, for example, support for energy efficiency or other measures to reduce electricity consumption, which in the long term can contribute to lower electricity bills and a more efficient power system. This chapter focuses on redistribution that is directly linked to electricity bills, and to a lesser extent on schemes that are linked to general welfare or energy efficiency. However, electricity savings and energy efficiency are one of several elements that can contribute to a stronger power balance.

17.1 Demand response

Support programmes for electricity costs are intended to help electricity customers in a situation of high prices. The subsidy means that they can afford to use more electricity than they would otherwise have done, despite high prices. At the same time, in a market-based system, high prices are a signal of scarcity, a situation in which the market is designed to facilitate increased production and reduced demand. Price signals are important for consumers to reduce demand in a tight situation. When consumers do not reduce demand in line with prices, this can cause prices to increase further - because the situation becomes even tighter. In the short term, the lack of response will negatively affect the power balance and security of supply, increasing the risk of rationing, as well as creating greater dependence on neighbouring countries and increased net imports.

Over time, price limits or support programmes may also dampen the consumer's incentives to invest in energy efficiency and lead to higher electricity consumption in society. This in turn drives up prices in the wholesale market, resulting in a higher spot price. If an increased consumption level is to be covered, it must be met with increased production, which in turn will put pressure on natural areas, or alternatively lead to a need for higher imports. A higher spot price results in higher government revenue, but also higher government expenditure to cover the difference if the government subsidises the retail price. The high prices in the wholesale market that come as an indirect effect of consumer subsidies may provide an incentive to invest in new power, but not necessarily with greater efficiency than direct government subsidies for development. An exception could be schemes that dampen retail prices at the expense of power producers' revenues, as these could have a negative impact on investment signals if they lead to uncertainty about future earnings.

In a future power system with a higher proportion of wind power and solar power that cannot be regulated, flexibility will be more expensive in the foreseeable future. There may therefore be a need for greater flexibility on the demand side. Support schemes that dampen price signals, and especially fluctuations in price signals, may reduce consumers' incentive to change their behaviour and reduce access to consumer flexibility.

It is difficult to quantify the extent to which electricity subsidies or price limits lead to increased consumption. We have limited knowledge of how consumers might react to different price and subsidy levels. In a country that relies on electricity for heating, there is a big difference in how much different consumers will be able to cut consumption when electricity prices are high and the weather is cold. This will depend on each consumer's normal consumption and ability to pay, as well as opportunities to use alternative heating such as wood burning. In chapter 8.9 we describe the price sensitivity of electricity consumers. Despite the electricity subsidy scheme that ran throughout 2022, it was measured that Norwegian households cut their electricity consumption significantly in the same year. At the same time, it is uncertain whether consumption would have been reduced even more if we had not had the electricity subsidy. In southern Norway, a large temperature-adjusted decrease of 14 per cent was measured, which indicates that households went a long way in adapting to reduce their electricity costs. As described in 8.9 there are also large variations within the business sector in the ability to adapt to increased electricity price levels in the short term. Especially in industries where electricity is used as an input factor, consumption is often inflexible.

17.2 Measures for households, the voluntary sector, agriculture, business and industry

Support measures can be permanent or temporary. European-wide rules allow for temporary redistribution measures in times of crisis, and to a lesser extent for permanent redistribution measures in normal times. This is justified by the desire to limit the negative effects that interventions in retail prices can have on consumers' demand response and possible consequences for the power system in the form of weakened security of supply and delaying the green shift. This chapter assesses measures that are intended to have a permanent duration (such as a two-price system for households and the sale of electricity at production costs through government CfD schemes), as well as measures that are intended to have a temporary duration in a crisis situation (such as different variants of electricity support or discount schemes). All support schemes will involve consumers paying less than the electricity price in the wholesale market.

When we assess the effect of various measures on the power system, the measures will have different effects if they are temporary or permanent. Permanent support measures will result in permanently higher demand and possibly also less demand flexibility than a situation without measures, and the effects on the power system will then have to be mitigated with other measures to increase production and flexibility in other ways to avoid negative effects as far as possible. Temporary measures will also have the same type of effects, but temporary and weaker. On the other hand, a measure that is temporary can still create expectations that the measure will be reintroduced at higher prices later. In this way, temporary measures can still have a permanent effect on, for example, the willingness to make investments to reduce consumption or choose, for example, a fixed-price contract to protect against high prices.

To varying degrees, companies will be able to pass on increased electricity costs to their customers. In the short term, the opportunity will be limited. Companies that compete in international markets have little ability to influence the price level of the products they sell. In general, price differences between countries or regions affect the competitive conditions for companies. For companies that are able to raise prices, increased product prices may lead to reduced sales and thus poorer profitability for the company, so that lost sales must be balanced against lower earnings. In general, opportunities for adaptation will be greater over time, as measures can be implemented that affect electricity consumption in a situation where the markets are relatively stable. This does not remedy lasting price differences between countries or areas. Households and the voluntary sector have little or no opportunity to pass on costs, but here too, electricity customers will be able to make adjustments to a greater extent over time.

It is demanding to organise measures for all customer groups, both households and businesses, that are effective and do not have high administrative costs. These are lessons learned during the pandemic and with the electricity subsidy programmes. A support scheme can be application-based to increase accuracy, but will still be dependent on setting criteria that target the scheme towards the desired recipients.

17.3 Legal assessment of support measures

This section is based on legal assessments written for the committee (Hjelmeng 2023, Mathisen 2023).

Support measures aimed at curbing electricity prices for end users can be designed in different ways, and choices about design will affect the extent to which the measures can be challenged on the basis of common European market and state aid rules. Examples of key choices are the role of the state, which consumer groups are covered by the measure, whether the measure aims to reduce retail prices to a level below the spot price in the wholesale market, and the duration of the measure - whether it should apply for a limited period (for example, until a temporary price crisis is over) or on a permanent basis, including during normal times. It is important to note that pan-European rules are constantly changing in response to new political contexts, and that in this sense the room for manoeuvre is dynamic.

Public aid to competing **undertakings** may distort competition and is generally prohibited by the EEA Agreement (depending on the extent of the aid). Article 61(1) EEA contains a general prohibition on aid granted from public funds. The prohibition is wide-ranging and covers subsidies, selective tax relief and/or relief of costs that would be incurred under normal market conditions. However, there are exceptions. For example, the agreement provides a basis for exemption from the prohibition if there is a crisis in the economy, as has been the case in the electricity price crisis. This exception is interpreted narrowly. But it has allowed temporary electricity subsidies to Norwegian businesses. Throughout the crisis, the Commission has adopted a temporary framework for state aid (discussed in more detail in Chapter 11), which streamlines and allows faster processing of the Commission's, and indirectly ESA's, notifications of crisis aid. This means that measures can be implemented more quickly if they are designed according to certain rules, such as that the measure is designed so that customers still have some incentive to reduce consumption despite the aid. Because the electricity price crisis is considered a temporary situation, it can be expected that the room for manoeuvre to support businesses will be tightened as the crisis subsides. In future economic crises with an EEA dimension, it is likely that the Commission will take a similar approach, and it can be assumed that ESA will follow the Commission and apply such temporary options accordingly.

Where the purpose is to relieve industry of high prices as an input factor, according to Mathisen (2023) it is difficult to see any other exception to the prohibition on state aid than where there is a crisis in the economy. The exemption cannot be utilised in cases where the challenges only consist of high electricity prices in certain parts of the country. However, it can be investigated whether there is room for manoeuvre for price-equalising measures that do not involve state subsidies.

State aid aimed at ensuring that an important project of common European interest can be realised may in some cases be compatible with the EEA Agreement. An example of such a project is the green transition, where the state aid rules largely allow for support to finance climate measures such as energy efficiency and the development of clean energy production. These are measures that can help to strengthen the Norwegian power balance, and energy efficiency will also be a good preventive measure that can put consumers in a better position to meet increases in electricity prices or new electricity prices in the future. What is defined as an important project of common European interest will depend on the EU's political agenda, and this is another example of how state aid rules can be dynamic.

For Norway, the agricultural sector is excluded from the scope of the EEA Agreement. This provides a special opening for state aid to a number of industries. For example, Norwegian authorities have relied on the "agricultural exemption" in the electricity subsidy to agricultural enterprises, greenhouses and irrigation teams (Mathisen 2023). During the next electricity price crisis, or for that matter on a more permanent basis, Norwegian authorities can provide support to agriculture in the form of compensation for high electricity prices without violating the EEA Agreement's state aid rules.

In its communication to the Member States when energy prices began to rise in autumn 2021, the Commission writes: "*Measures of a general nature, equally helping all energy consumers, do not constitute State aid. Such non-selective measures can e.g., take the form of reductions in taxes or levies, a reduced rate to the supply of natural gas, electricity or district heating.*"[63]

Against this background, it may be asked whether it is possible to introduce a general, non-selective support programme that covers all businesses without it being considered state aid. For example, lowering corporation tax for everyone would be a general non-discriminatory scheme. More targeted schemes, which in isolation may be permitted in relation to one industry, may involve indirect support for another. In this context, it is important to remember that the EU's regulations and assessment of legal measures are also under development, including in this field, which means that the scope for supporting Norwegian businesses may also increase.

[63] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021DC0660 (page 9)

Support to households and consumers that are not defined as industries (e.g. in the voluntary sector) is not covered by the state aid rules.

If the state is to assume a role in the market, for example in the sale of electricity, this should be assessed against the market participant principle, which generally requires that public acquisition activities must be carried out in a manner that would also be relevant for a rational private operator. If the public enterprise sells electricity at a lower price in the market, this may still be considered state aid. However, there is some room for manoeuvre if the sale is due to commercial assessments made by the enterprise itself (for example, that it is necessary to lower prices during periods to retain customers, or to help customers through financial challenges because it will be rational in the long term). This will involve market-conforming behaviour - it is only if sales at below cost are made through political control that support will be attributed to the public sector. In practice, the possibility of establishing a state-owned electricity supplier is therefore limited, but not impossible. They will have little opportunity to offer a lower price than other electricity suppliers (see chapter 16).

17.4 Choice of measures and analytical approach

The measures assessed in this chapter are derived from the public debate and input received by the Committee. Furthermore, AFRY and Menon Economics submitted a report to the Ministry of Petroleum and Energy in September 2022, in which several of the measures considered by the committee are discussed (AFRY og Menon 2022). Measures are also discussed in Prop. 1 S (2022-2023). The measures assessed in this chapter have in common that they involve elements of support and aim to reduce the price of electricity for consumers. The assessments can be used to shed light on other forms of support measures that have not been assessed in this chapter, as the effects of such measures will in most cases be similar. If you envisage proposals that combine different measures, you can see the effects by combining the assessments of the different measures.

The measures are divided into three main categories, where the first contains measures that set a politically determined *limit on* the retail price, the second contains measures that set a politically determined *discount* on the retail price, and the third a *direct revenue transfer* to the consumer.

Politically determined caps on retail prices
A price cap, or maximum price, sets a politically determined upper limit for all or part of the retail price. In this chapter, it is assumed that the organisation of the wholesale market remains unchanged, which means that a price cap can only be achieved through the use of public support to cover the difference between the spot price and the subsidised retail price. The level of a price cap can be defined on different bases, and the scheme can be organised to reflect changes in the spot price to different degrees.

Politically determined discount on the retail price
Measures can be designed to provide a discount on the retail price, without setting a price cap. In such schemes, a percentage discount will be given based on consumption. Compared to schemes with various forms of price caps, the consumer will have a greater incentive to save electricity in situations of scarcity, as the spot price is always reflected as a percentage of the retail price. The government's electricity subsidy scheme for households was an example of a politically determined discount, but when the discount approaches 100 per cent, the effect approaches the maximum price. Other examples of discount schemes include variable VAT, where it is decided that VAT will be reduced in relation to a rising electricity price, or different variants of electricity subsidy schemes.

Politically determined income transfer to the consumer
A direct income transfer to the consumer from the state differs from electricity subsidy and discount schemes because it is not directed directly at the electricity bill, but allows the consumer to choose whether the increase in income should be used to pay a higher electricity bill or for other purposes. One of the advantages of the scheme is that the price signal and incentive to save electricity is retained to a greater extent, and that it can therefore have fewer negative effects on the market than electricity subsidies and rebate schemes. The housing subsidy is an example of a similar scheme.

17.5 Assessment of measures

17.5.1 Politically determined caps on retail prices

Schemes involving price limits can be designed in many different ways. Common to all variants is that they will require some form of subsidisation, typically via the national budget, as it is assumed that the organisation of the wholesale market remains unchanged and the difference between the spot price and the mitigated retail price must be covered. All forms of price limits could provide the covered consumers with more predictable electricity prices and mitigated costs, where the degree of predictability and mitigation will depend on the price level set or the extent to which the scheme allows the spot price to be reflected in the retail price. If the scheme provides broad coverage, those who consume the most will also benefit the most. Financing via the national budget will always have an opportunity cost, even in schemes where the subsidies are financed through a levy on power producers' revenues, as the same resources could alternatively be used for other welfare purposes.

As discussed above, a key disadvantage of measures that set price limits is that consumers are less incentivised to respond to signals of scarcity in the market. In chapter 16 we discuss various measures that can facilitate increased uptake of price hedging agreements, including fixed price agreements. With the right design of fixed price agreements, marginal pricing can be retained. The introduction of politically determined price limits will reduce incentives to enter into fixed price agreements in the private market, even in cases where the price limit is to apply over existing fixed price contracts, as the price limit increases predictability for the consumer.

17.5.1.1 Authorised maximum price

A maximum price means that the authorities set a maximum price in the retail market, so that the consumer's cost of purchasing electricity hour by hour never exceeds a certain amount. Electricity must still be purchased from the wholesale market, where the price may be higher than the maximum price. The difference between the wholesale price and the retail price means that government support is required to provide end users with a maximum price. In this case, it is assumed that the state pays electricity suppliers to offer an electricity price that is below their purchase price in the wholesale market, and that all electricity suppliers have equal opportunities to offer the maximum price.

The measure can be designed with varying duration and scope. A permanent scheme will have a greater impact on end users, but may also have a greater impact on the power system. The scope of the measure amplifies the effects; the more consumer groups that are included, the greater the effects on the power system will be. AFRY and Menon Economics have assessed the possible effects of a maximum price in the retail market in their report to the Ministry of Petroleum and Energy (AFRY og Menon 2022).

What is the price impact of the measure?
A maximum price could give consumers a more predictable electricity price and reduced electricity costs. The degree of price reduction and predictability will depend on the level of the maximum price and the duration of the measure.

How did the initiative affect the behaviour of actors along the value chain?
Consumers facing a maximum price will be less incentivised to respond to price signals of energy scarcity. The maximum price may also reduce the consumer's incentives to invest in energy efficiency.

A maximum price that is set low will have a negative impact on the market for fixed-price contracts, as the need for price hedging among consumers will be reduced. If customers with fixed-price contracts receive the same subsidies when electricity prices are high, the incentives to enter into fixed-price contracts could be maintained, but then consumers who have entered into fixed-price contracts will also be compensated for costs they do not have.

What consequences will behavioural changes have for the power system?
A maximum price could lead to higher consumption in the short and long term. If end users do not respond in situations of scarcity, security of supply could be negatively affected because consumption is not reduced. This will be negative for the power balance in the short term, and also for security of supply. Producers will be able to compensate for these effects by holding back production and storing more water in reservoirs. This in turn drives up prices in the wholesale market and will result in higher spot prices than would otherwise be the case, which in turn increases the level of subsidies that must be covered by the state. Prices in the wholesale market will increase. These price signals could provide incentives for investments in new power, but direct subsidies for investments will be more efficient and accurate for achieving new power development than a price signal driven by subsidies in the retail market, as the state can then directly finance the development. An end-user subsidy could also lead to higher consumption of goods other than electricity. Increased consumption will lead to a need for more power. This could mean greater dependence on neighbouring countries and increased net imports unless new power production corresponding to the increase in consumption is realised in Norway. The extent of these consequences will depend on the maximum price level and the duration of the measure.

What consequences will the change in the power system have for society as a whole?
A maximum price provides incentives for increased electricity consumption and electrification of fossil energy use, which in isolation can be positive for the energy transition. A maximum price for all consumers means that those who consume the most also receive the most support. To the extent that higher consumption is linked to higher income, the measure is poorly targeted at vulnerable groups. Tax and levy financing has a cost, although it is conceivable that a direct levy from power producers could help to cover this. This results in a generally higher tax and duty burden to maintain welfare.

What barriers exist to implementing the initiative
The scheme is relatively easy to administer, as the subsidy can be provided in the same way as the current electricity subsidy. Legally speaking, a permanent electricity subsidy scheme for households would be relatively unproblematic. For businesses, which are subject to state aid rules, a permanent support scheme will be challenged on the basis of state aid rules. In future crisis situations, it is likely that the state aid rules will open up for temporary support schemes, and in such a situation, a maximum price that covers businesses in addition to households and other actors may be a conceivable alternative to the electricity support scheme we have had. In that case, it should be assessed against the Commission's guidelines for state aid in the next crisis.

17.5.1.2 Authorisation regulated fixed price
The authorities set the price in the retail market so that consumers have predictability for a given price level. As with a maximum price, this means that there is a difference between the price in the retail market and the wholesale price, but the price difference in this measure can go both ways - the

price in the wholesale market can be higher or lower than the fixed price set by the authorities. This differs from a maximum price, where the price can vary below the price cap. It is assumed that the price in the wholesale market over time is higher than the regulated retail price, which results in the need for government subsidies. It is also assumed that the state covers the electricity suppliers' costs when the regulated price is below their purchase price in the wholesale market and collects any revenue when the regulated price is above the purchase price. All electricity suppliers have equal opportunities to offer the government-regulated fixed price. The measure can be designed with different duration and scope of consumers. The price can also be set for a shorter or longer period at a time. A similar measure that is only aimed at price equalisation and does not contain an element of support is assessed in Chapter 15.

What is the price impact of the measure?
A regulated price gives consumers a more predictable electricity price and, in this example, will also result in a lower price level. In periods of very low prices, consumers will have to pay more than the wholesale price.

How did the initiative affect the behaviour of actors along the value chain?
With a given price level, consumers will react less to price signals and have less incentive to rationalise energy use. A regulated price will most likely remove the market for other fixed-price contracts, as predictability is safeguarded in the government-regulated price and the support element will outcompete other forms of contract. This means that the electricity supplier segment will change to a large extent, as a result of all or parts of the market being regulated and the range of contracts being limited. There may still be a market for additional services.

What consequences will behavioural changes have for the power system?
Higher consumption and less flexibility can have a negative impact on security of supply because consumption is not reduced in situations of scarcity, and this can drive up prices in the wholesale market.

In periods when the wholesale price is lower than the regulated price, consumers will not have an incentive to increase consumption. This means that consumption and prices in the wholesale market are kept lower than they would otherwise have been, and entails a risk that power producers with regulated reservoirs will not be able to utilise water resources if they are unable to export power.

The extent of these effects will depend on the scope and duration of the programme.

What consequences will the change in the power system have for society as a whole?
Predictability for consumers can incentivise increased consumption, as uncertainty about future market development is mitigated. This can contribute to increased restructuring and electrification. Regulated prices as a support measure for all consumers are not accurate according to need and, as with a maximum price, will mean that customers with the highest consumption will also receive the most support.

What barriers exist to implementing the initiative
The scheme is relatively easy to administer and can be granted in the same way as the current electricity subsidy scheme. As with a maximum price, the business sector is subject to state aid rules. In future crisis situations, it is likely that the state aid regulations will allow for temporary support schemes, and in such a situation, a government-regulated fixed price could be a conceivable alternative to the current electricity subsidy.

Legally speaking, electricity subsidies for households will be relatively unproblematic.

17.5.1.3 Top price system for households - normal consumption and more expensive luxury consumption

A two-price system for households is a variant where households receive a certain volume, defined as normal consumption, at a politically regulated price. Consumption above normal consumption is defined as luxury consumption and must be paid at the spot price. The system can be designed in different ways, but the aim will be to reduce household expenses, or to respond to an expectation of a guaranteed supply of electricity at a low, predictable price, while at the same time exposing households to a certain degree to signals of scarcity in luxury consumption.[64] The Swedish Social Democrats' outline of a scheme for "Folkhemsel" resembles a two-price system for households, where the state buys a certain volume of electricity in the wholesale market and can offer a share of household consumption at a politically determined price. In this example, it is assumed that the state enters the retail market as a provider of a certain normal consumption at a politically regulated price that is below the wholesale market price. It is assumed that the state incurs a financial loss, i.e. the difference between the state's higher purchase price in the wholesale market and the lower price for normal consumption offered to consumers is covered by funds from the state budget.

The previous two-price system in Norway was more closely linked to power pricing. This was before we had market-based electricity sales in Norway, but even then the prices to households were designed to ensure that users covered the total costs of the power supply. The purpose of a single price for consumption below a certain power limit and a higher price for so-called overconsumption was to stimulate more even consumption over the course of the day and year. This system is therefore not entirely comparable to the two-price schemes that have been discussed in recent years.

What is the price impact of the measure?

A government-regulated fixed price for parts of consumption gives consumers a more predictable electricity price and reduces their expenses, but the degree of reduction and predictability will depend on the level of the price. A fixed price will provide the greatest predictability, but will also mean that in cases where the wholesale price is very low, the downside is not realised. The greater the proportion of consumption covered, the greater the extent to which predictability and lower prices are addressed. A lower price for parts of the consumption could result in higher demand and therefore drive up the wholesale price. This means a higher price for luxury consumption. Overall, the price may be lower on average, but the effect will vary from customer to customer depending on the size of the consumption.

How did the initiative affect the behaviour of actors along the value chain?

All consumption where the price signal does not reach the consumer may result in higher consumption, but given that the limit for basic consumption is set to only what is necessary, the effect is reduced. The effect in the short and long term will be less than with a maximum price or fixed price for all consumption. Since consumers are still faced with parts of their consumption at the current price level, they will still have incentives to improve energy efficiency, but this again depends on how much of their consumption is defined as basic consumption.

It will still be relevant for consumers to enter into fixed-price contracts for luxury consumption, but the measure overall could have a negative effect on the demand for fixed-price contracts since part of the consumption will already be secured. In this example, electricity suppliers other than the

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[64] In periods of low power prices, some have advocated the opposite approach - normal consumption can be purchased at market price, while luxury consumption is taxed or sold at an extra high price.

state-owned company can compete to offer contracts for the remaining "luxury consumption" and any additional services.

What consequences will behavioural changes have for the power system?
The fact that only parts of consumption have a maximum price or fixed price will result in a smaller increase in consumption than when all consumption is included. This will have a smaller effect on security of supply, power balance and reservoir utilisation than with a maximum price or regulated price for the entire consumption.

What consequences will the change in the power system have for society as a whole?
The top price system addresses the need to cover the minimum electricity requirement at a lower price and avoids those with the highest consumption getting the most. This is achieved as long as the base consumption is not set too high. This also reduces the cost of the scheme and provides an incentive to reduce other consumption when prices become too high. The fact that the subsidy is limited to a minimum consumption reduces the negative effect of a lack of price signals from the subsidy.

What barriers exist to implementing the initiative
The scheme can be administered as a new offer in the retail market, where households have the opportunity to choose to buy a certain volume of electricity at a politically determined price from a state-owned electricity sales company or a scheme administered like the current electricity subsidy. A key challenge will be to define what volume should constitute normal consumption and what price it should come at, given differences in household size and other factors that affect consumption. A similar scheme for businesses would be difficult to implement, as it would not be possible to define how consumption should be divided into two categories, and it would also challenge the state aid regulations.

17.5.1.4 Redistribution from government support programmes (two-sided CfD scheme)
The EU's forthcoming power market reform will provide new guidelines for support schemes for power generation, cf. chapter 11, with two-sided contracts for difference as the preferred scheme. The difference contracts will initially be aimed at investments in well-developed, non-fossil fuels technologies with low and stable operating costs. The EU points to wind power, solar power, geothermal power, nuclear power and hydropower without reservoirs. These are technologies that *can* receive high resource rent revenues if more expensive technologies set the price in a marginal pricing system, and which do not contribute flexibility to the power system. A government-guaranteed price is set for the producer to ensure that the investment project is profitable, and the government covers the difference between this price level and the wholesale price when the latter is lowest. Furthermore, a revenue cap is set so that the government receives the revenue from the price difference if the wholesale price is higher than the contract price for shorter or longer periods. In the EU's proposed regulations, it is envisaged that these revenues during high price periods will be distributed back to all consumers of electricity, relative to consumption and regardless of consumer group.

Norway has not yet utilised differential contracts as a support system, but the Ministry of Petroleum and Energy has invited tenders for two-sided differential contracts for Southern North Sea II.

Assessment of the measure
The proposal for this new use of two-sided CfDs has been controversial in the EU because it could open up new opportunities to support consumers, including businesses, in normal times. Furthermore, this raises concerns that different CfD schemes in different EU countries could lead to distortion of competition in the single market. Whether such room for manoeuvre is opened

depends on the final rules for the design of such CfD schemes, which have not yet been agreed upon in the EU.

In order for the scheme to become a permanent measure with steady support for consumers, the rules must be designed so that over time the state receives net revenue from the two-sided CfDs, which can then be redistributed to consumers so that they receive a retail price that is below the wholesale market price. For most producers, it will not be rational to participate voluntarily in such a scheme, so the state must be able to require producers to participate and also to set a politically determined contract price. The scheme will have the greatest effect if existing power plants can also be covered, which is why this has also been a key discussion between EU countries. Such a scheme would resemble a basic rate tax, where the producers' income is redistributed by the state to consumers. However, the scheme will differ from the basic rate of return tax if the regulations allow for exemptions from the state aid rules that allow businesses to benefit from a lower retail price through a state CfD scheme. It is then possible that countries that have a high proportion of relevant technologies in the national power mix and a willingness to tax producers and subsidise industry end up with a competitive advantage they would not otherwise have had. The relationship between the proposed two-sided CfD scheme and the state aid rules is currently unclear, and is one of the topics still being discussed between EU countries in connection with the reform.

If the rules for the scheme are designed so that participation is voluntary, the contract price is based on competition and no exemptions from the state aid rules are granted for commercial electricity customers, the state will probably not be able to receive net revenues and the scope for government redistribution will be narrower. The scheme can nevertheless help to mitigate price peaks and provide greater predictability for consumers, particularly households and other actors not covered by the state aid rules, especially during peak price hours or periods. The effects of state redistribution where the level of support is determined by the contract price in a CfD will in all cases be similar to the effects of a maximum price, but the extent depends entirely on how the scheme is designed and how revenues are redistributed.

17.5.2 **Politically determined discount on the retail price**

Discount schemes involve a subsidised, percentage discount in the retail price in relation to the spot price, but do not set a definitive price limit that the retail price cannot exceed. The government's electricity subsidy scheme for households is an example of a scheme with a high discount, where 80-90 per cent of the price difference between 70 øre and the spot price is covered by the state. If the discount had been set at 100 per cent of the price difference between NOK 0.70 and the spot price, it would in practice constitute a price ceiling. Discount schemes can mitigate the consumer's expenses and provide greater predictability. The degree of mitigation and predictability will depend on the price level at which the measure takes effect and the size of the percentage discount. To the extent that the percentage discount approaches 100 per cent, the effects will resemble the effects of a price cap where the consumer is not exposed to scarcity signals. The discount will have to be financed from the national budget, with the opportunity costs this entails.

The effects that discount schemes can have on the power system are largely similar to the effects of price limits, but as long as the discount is set at less than 100 per cent, the consumer will still have a certain degree of exposure to scarcity signals. This can help to reduce the negative effects of the measure on the rest of the power system, compared with a specific price limit that exposes the consumer to scarcity signals to a lesser extent. Total electricity consumption may nevertheless increase, with the consequences this may have for energy efficiency and security of supply, and incentives to enter into fixed price agreements will be reduced.

17.5.2.1 Percentage reduction on price

The electricity price to consumers is set at a percentage reduction from the wholesale price. The scheme can also be designed so that this discount has a "floor", i.e. it kicks in at a specific price level.

What is the price impact of the measure?

The reduction will dampen price fluctuations and give the consumer a lower price. How much will depend on the level at which the measure takes effect and the size of the percentage discount. To the extent that the percentage discount approaches 100 per cent, the effects are almost equal to a maximum price, and the price signals from the Wholesale Market will not be visible to the consumer.

How did the initiative affect the behaviour of actors along the value chain?

As long as the percentage discount is not too high, consumers will recognise the price signal and reduce demand, but to a lesser extent than if they are fully exposed to the wholesale price.

The incentives to invest in energy efficiency are reduced since the price the consumer faces is lower. This could affect the demand for fixed price contracts as the scheme will reduce the risk of being exposed to high prices and it will not be necessary to enter into a fixed price contract to manage the risk of high electricity prices.

What consequences will behavioural changes have for the power system?

With a lower price, you will see higher consumption and less response to price. This will have the same effects as the maximum price. Lack of response from end users in situations of scarcity has a negative impact on security of supply because consumption is not reduced in situations of scarcity. This will be negative for the power balance in the short term, as people will not respond to the high prices to the same extent. Security of supply will be affected as the price will not signal scarcity, so consumers will reduce their consumption. Producers will initially compensate for this by holding back production and storing more water in reservoirs. This in turn drives up prices in the wholesale market and will result in higher prices there than would otherwise be the case. This can in turn increase subsidies. Prices in the wholesale market will increase, and the price signals will provide incentives for investments, but direct subsidies for investments will, in isolation, be more effective than an end-user subsidy.

Consumption will increase and more power will be needed. This will mean greater dependence on neighbouring countries and increased net imports.

What consequences will the change in the power system have for society as a whole?

The higher the consumption, the more support you receive, and with a correlation to high income, high-income groups will receive more than others.

What barriers exist to implementing the initiative

The scheme is relatively easy to administer, as the support can be provided in the same way as current electricity subsidies. In relation to the state aid regulations, a percentage reduction in the electricity price to households is unproblematic.

For businesses, a permanent support scheme will be challenged on the basis of state aid rules. In future crisis situations, it is likely that the state aid rules will open up for temporary support schemes, and in such a situation, a percentage reduction in the electricity price that covers businesses in addition to households and other actors may be a conceivable alternative to the electricity support scheme we have had.

17.5.2.2 Variable value added tax

Reduced VAT rate on electricity when prices are high is a measure that is a version of the equal percentage reduction price with effect from the first krone.

Assessment
This measure has the same effects as a percentage reduction in the price. Since it has the same effect as a percentage reduction from the first krone, it is better to use this measure and leave VAT unchanged. Value added tax is a general tax on domestic consumption of goods and services. Its purpose is to raise revenue for the state. Reduced rates, exemptions and exemptions reduce government revenue and increase administrative costs for both businesses and the Norwegian Tax Administration. Measurements have shown that the administrative costs for businesses increase significantly when they have to deal with multiple rates. This will apply in particular if the VAT rate is to vary over time, depending on the price of electricity. It follows from the practice of the European Commission that reduced VAT rates are not considered as possible state aid, provided that the rates are imposed in accordance with the VAT Directive. As this directive is not part of the EEA Agreement, Norway is in principle free to impose other rates as well. However, if they do so, it is considered indirect state aid that must be notified to and authorised by ESA. Businesses usually have the right to deduct VAT, so such a support measure will not apply to most businesses.

17.5.2.3 Price equalisation between bidding areas
The spot price can vary over shorter and longer periods in the different bidding areas in Norway. The prices faced by households and businesses therefore differ depending on the region. The measure is to introduce a scheme in the retail market so that all households and businesses face the same price regardless of region, or the scheme may be limited to some consumers. Note that we do not equalise the wholesale price, but that we are looking at a transfer from end users in low-price areas to end users in high-price areas. This is also assessed as a wholesale market measure in chapter 14.4.7. There is some overlap, but as a pure retail market measure, it is conceivable that not all consumer groups are included and that there is more flexibility in how schemes are organised. We envisage the scheme being implemented as a budget-neutral transfer through a tax in low-price areas and a subsidy in high-price areas, so that everyone has the same price. The measure is granted regardless of which contract you have. One could envisage an additional transfer via the national budget to bring the price down further, but we do not consider this further here. The effects of this can be seen in the sections on maximum price. Here we wish to clarify the effects of price equalisation.

What is the price impact of the measure?
The measure will result in lower prices for consumers in high price areas, but higher prices for those in a low wholesale price area. The effect will depend on consumption in each bidding area, in some cases the price may be significantly higher in the low price area, while it will not be correspondingly lower in the high price area due to the budget neutrality of the scheme. If some types of consumers are excluded from the measure and they buy directly in the wholesale market, the price may be higher for these consumers, as the price signal for some consumers in the area will be weaker, while in areas with a low wholesale price, the consequence may be an even lower price due to consumers facing a different higher price. The price equalisations may stabilise the price somewhat across seasons and days, but the measure will not result in an average lower price for end users without an additional transfer from the state. Without a transfer, a weighted average price will increase due to the supply and demand effects described below.

How did the initiative affect the behaviour of actors along the value chain.
Electricity suppliers will be able to continue as they do today. For spot price contracts, the change will not be so great, but the price for consumers will be slightly less transparent. If the subsidy or tax is conceivably granted regardless of the contract, this means that the total price you pay for electricity with a fixed price contract will be more unpredictable since you do not know what you will pay in tax or receive in subsidy. However, the incentive to hedge is less affected. Fixed-price

contracts may become more expensive in high-price areas, since the measure drives up the wholesale price in high-price areas. The effect will be the opposite in other areas.

What consequences will behavioural changes have for the power system?
The wholesale price will be higher in areas with high prices and lower in areas with low prices. One consequence will be that there is a risk that many new businesses will be established in areas with shortages and not in areas with surpluses and low prices. This could have consequences for security of supply in the short and long term. More water is retained in reservoirs in high-price areas, and less in low-price areas. Low-price areas will increase net exports, while high-price areas will have lower net exports. Due to the changes in the wholesale price, the investment signals will be stronger in high-price areas and lower in low-price areas, so you can achieve a faster equalisation of capacity between bidding areas, but it may also mean that you have to make unnecessarily expensive investments in high-price areas when it would be better for the economy to have established businesses and demand for electricity in low-price areas.

What consequences will the change in the power system have for society as a whole?
The measure will mean that all consumers will face the same price. This is favourable for companies that will have equal terms of competition for electricity and can establish themselves regardless of the electricity price.

Since the scheme results in higher prices in areas with already high wholesale prices and lower prices in areas with low wholesale prices, this could steer investment in a less cost-effective way. This can trigger very expensive investments in the grid and production that could have been solved in a cheaper way for society.

What barriers exist to implementing the initiative
The scheme may have negative effects on security of supply and may result in a higher average price over time. Generally a costly scheme for society, even if it is assumed to be budget-neutral. In practice, it could be implemented in a similar way to the current electricity subsidy, but will mean that some people will receive a surcharge on their bill instead of a subsidy. The scheme means that someone with a low price today will have to accept a higher price.

The scope for introducing price equalisation should be assessed against the market rules in the EU's energy market packages, both those currently in force and those that may become applicable. Should Germany be divided into different bidding zones, this will probably be discussed there. For industry, which is covered by state aid rules, there is also a risk that the scheme could be challenged on the basis of state aid rules. In this case, however, a budget-neutral scheme is described that does not require a contribution of own funds from the state. The question can be examined in the light of schemes in other EU countries, such as Italy's Prezzo Unico Nazionale (PUN), which equalises prices between six Italian bidding zones (see also Chapter 15) and which has not been problematised as state aid. If the scheme is organised as an electricity subsidy only for the most expensive areas, this would be legally feasible for households, but probably more problematic for businesses, with the possible exception of the scheme if it is defined as non-selective. In future crisis situations, it is likely that the state aid regulations will allow for temporary support schemes, and in such a situation, an electricity subsidy for price equalisation may be legally feasible.

17.5.3 Politically determined revenue transfer to the consumer.

Any measure that changes the price signal is accurate in that it gives the consumer a lower price, but it is problematic as described in the chapter on demand response since the efficiency of the system decreases. The price signal can result in investment on the supply side, while it could be cheaper to reduce demand. In this section, we look at measures that do not affect the price directly.

17.5.3.1 Cash transfers to all households

All households receive support in the form of cash transfers in situations with high electricity prices. A normal price level for electricity is defined, and the scheme kicks in if the spot price increases beyond this level. Each household is then paid a subsidy amount corresponding to a percentage of the spot price above the normal level, based on a typical household's average consumption. The subsidy does not vary with the household's own consumption, and differs from the government's electricity subsidy schemes as the consumer can choose to reduce consumption in response to the price increase, but still receive the subsidy and possibly use the cash transfer for purposes other than paying the electricity bill.

What is the price impact of the measure?
The measure will not result in either low or more stable prices, but will give the average consumer the ability to pay to handle high prices.

How did the initiative affect the behaviour of actors along the value chain?
The measure means that all consumers still face the wholesale price and can act in the short and long term at the correct price in the market. The demand response may be somewhat smaller than without a transfer, since there will be an increase in income when the price goes up, but we assume that this effect will be small. The incentives for energy efficiency will be present, and you can also choose to use a cash transfer for this.

The cash transfer will remove the risk for the average consumer, so the incentives to sign a fixed price contract will be lower as the risk will be managed by a cash transfer, but for consumers with higher consumption, the incentives will still be in place. If the normal price level is set higher, the risk will also increase and the need for a fixed price will be less affected.

What consequences will behavioural changes have for the power system?
Storage capacity utilisation, security of supply, and the power balance, net exports will be almost unchanged, but the cash transfer provides increased income and may be somewhat price-driving and result in some increased demand, but less than the maximum price or fixed price, so the effects are also much weaker.

What consequences will the change in the power system have for society as a whole?
This scheme gives everyone an equal "ownership share" of what many consider to be extraordinary profits from power generation. In principle, this is not the way we have organised the distribution of this type of income in Norway, such as oil revenues. However, it can be defended on the basis that the value of retaining the current market design in the wholesale market will directly benefit consumers.

The measure will still provide good incentives to reduce own consumption or invest in own production since the same price is still faced. Like all other measures that require a transfer, there is a tax financing cost associated with this.

What barriers exist to implementing the initiative
There are various practical solutions for what could be defined as a normal price and average consumption per adult and child. In the current system, it is not possible to make an immediate cash payment to residents, so a scheme for this must be established. However, this is something that can be solved.

Legally speaking, electricity subsidies for households will be relatively unproblematic. This support programme will only cover households. The administrative costs for a type of scheme for business and industry would not be possible in practice, as it would be difficult to define what would be an average consumption for a company and receive a cash transfer on that basis. It would also challenge the regulations for state aid.

The current system does not immediately allow for a cash payment to households, which would have to be established.

17.5.4 Cash transfer for certain groups

One version of a cash transfer to all is a transfer only to vulnerable groups or low-income households. In the Norwegian debate, high electricity prices have often been referred to as a distributional problem, and the government's increased tax revenues have helped to finance the costs of, for example, the electricity subsidy, which was aimed directly at consumers' electricity bills. Increased housing subsidy is another measure that has been implemented, and this has fewer negative effects on the market than the general electricity subsidy for everyone. However, the housing subsidy only supports the most vulnerable. If an electricity subsidy is only introduced when the price is at a certain level, a more comprehensive income transfer or cash transfer to the consumer has other effects. One of the advantages of the scheme is that the price signal is retained.

An increase in the housing subsidy and electricity supplement for students is an example of such a measure. Housing benefit is a relatively accurate measure for the most vulnerable groups. In principle, this is a good way to provide support, but there may be vulnerable groups without housing subsidy that will fall by the wayside. It is difficult to identify the vulnerable groups, but this does not mean that we should not look at measures that go beyond regular housing benefit. In situations with very high prices, the group of vulnerable people will increase. Better insight into this would be a good preparation for facing new crises in the future. Whether the vulnerability of these groups should be addressed through measures in the electricity market is a question for decision-makers to consider. Parts of the fourth energy market package recommend support that is not aimed directly at electricity bills, but that schemes such as housing subsidies should be prioritised, although there is scope for temporary interventions in retail prices for vulnerable households.

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