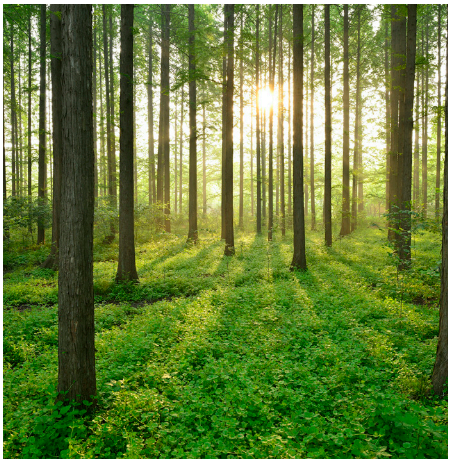
POWER PRICE DISTORTIONS OF SUBSIDY SCHEMES IN NORTHEN EUROPE

REPORT 2026:1169



NEPP

Energiforsk

Power price distortions of subsidy schemes in Northen Europe

EA ENERGIANALYSE

ISBN 978-91-89917-12-5| © Energiforsk February 2021

Energiforsk AB | Phone: 08-677 25 30 | E-mail: kontakt@energiforsk.se | www.energiforsk.se

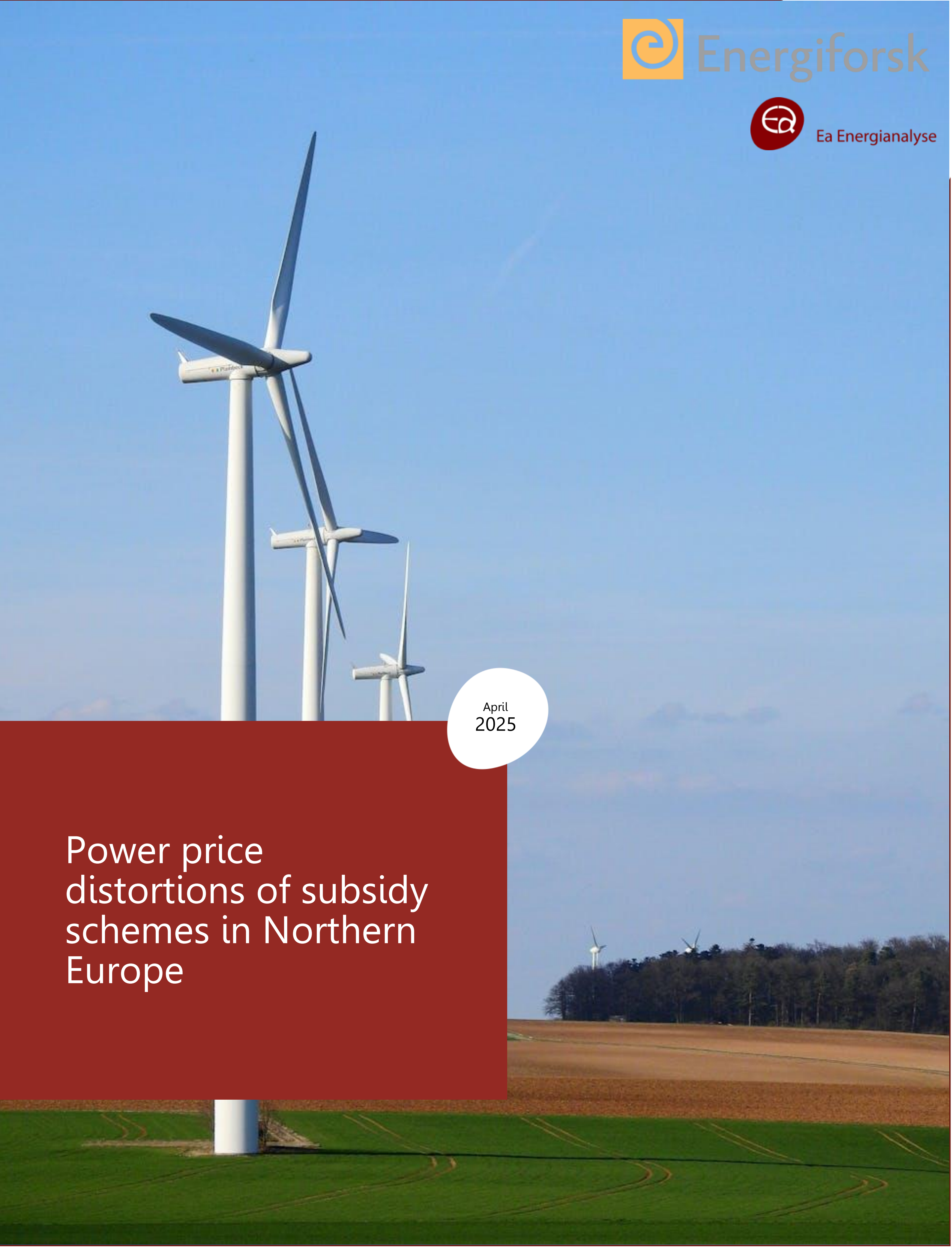
Foreword

This report analyses how different electricity generation support schemes may affect future electricity prices and power generation in Northern Europe, with a particular focus on Sweden. The analysis has been conducted within the framework of the Nepp research project (North European Energy Perspectives) as input to the 2035 projects within Nepp.

The results show that support schemes for fossil-free electricity generation have only a limited impact on power system dispatch and on average electricity prices but may lead to certain shifts between generation technologies as well as moderate changes in so-called capture prices. The study thus contributes new knowledge on how support schemes can influence the functioning of the electricity market in a future Nordic and European energy system.

Energiforsk would like to extend its special thanks to the authors of the report. These are the results and conclusions of a project, which is part of a research programme run by Energiforsk. The author/authors are responsible for the content.

Energiforsk



Energiforsk

Ea Energianalyse

April
2025

Power price distortions of subsidy schemes in Northern Europe

Part of the North European Energy Perspectives Project (NEPP)

Prepared for:

Energiforsk AB
Phone: 08-677 25 30
E-mail: kontakt@energiforsk.se
www.energiforsk.se

Developed by:

Ea Energianalyse
Gammeltorv 8, 6 tv.
1457 København K
www.eaea.dk

Contents

Executive summary

The aim of this study is to analyse how different subsidy schemes can impact future electricity prices and generation in Northern Europe with a focus on Sweden. The analysis has been prepared by Ea Energy Analyses for Energiforsk as part of the multidisciplinary research project North European Energy Perspective Project (NEPP) which examines the development of Sweden's energy system in a Nordic and European context. The Balmorel model is applied, which is a fundamental partial-equilibrium model finding least-cost solutions based on assumptions such as the development of fuel prices, demand development, technology costs and characteristics, renewable resources, and other essential parameters. For this project information about European subsidy schemes have been collected, allowing the model to successfully replicate the magnitude of negative power prices, observed historically in the European energy system.

Scenarios with different power generation subsidies for solar PV, onshore & offshore wind power, nuclear power, and hydro power are modelled and applied to a European capacity development towards 2040. The development reflects high electrification and build out with renewable energy pursuing long term net zero emission. Sweden sees a strong market driven development with onshore wind along with 2.5 GW of new nuclear capacity by 2040 facilitated by the Swedish government through a CfD scheme.

The analysis examines the extent to which different subsidy schemes may influence the dispatch of the energy system and the power prices in the day-ahead market. The study does not analyze how subsidy schemes may impact investments in power generation technologies.

The model results show that subsidies to fossil free generators do not significantly change the dispatch of the power system; implying only marginal effects on fuel use and CO_2 emissions. However, some shifts are observed between different low OPEX technologies reflecting differences in both the structure of subsidy schemes and the variable operating costs associated with each technology. Guaranteeing new Swedish nuclear generators a fixed electricity price through a conventional CfD lead to a 9% increase in their generation compared to a situation where the nuclear generators attain a financial CfD and bid in the market according to their variable operating costs (this corresponds to an increase of approx. 3 % in total Swedish nuclear power generation). Additionally, the modelled subsidy schemes lead to modest increases in onshore wind power and solar PV based electricity generation in Sweden, due to reduced curtailment.

Including the effects from subsidy schemes to some extent distort power prices in the modelled European countries but the power price formation is not fundamentally altered. Thus, the subsidies only lead to moderate reductions in power prices in the various European bidding zones, and the price reduction mainly occur in periods where solar PV, wind power, or nuclear power are the marginal power producers. Compared to a scenario without subsidies, the modelled subsidy schemes lead to reductions of approx. 2-3 €/MWh in 2040 average wholesale power prices.

The subsidy schemes lead to capture price reductions in Sweden of approximately 1-2 €/MWh for wind power and solar PV, approximately 2-3 €/MWh for nuclear power, and approximately 1 €/MWh for hydro power by 2040; overall corresponding to capture price reductions of 3-6 %. As such, the revenue from electricity sales for these non-fossil technologies is only reduced to a modest extent.

The total number of negative power prices in the modelled European countries, is more than doubled from 2025 to 2040. This reflects the increasing shares of wind power and solar PV in the European power mix. However, in Sweden the picture is more nuanced. The number of negative power price events increases somewhat towards 2040 in SE3 and SE4, whereas they are reduced in SE1 and SE2. The fact that formation of negative power prices is increased in some (most) power regions while reduced in other regions likely reflect the impact of two overall factors influence the result in opposite ways: The increasing share of wind power and solar PV in the power mix facilitates more negative power prices, while the increasing share of flexible electricity demand, e.g. from power-to-x for example in Northern Sweden, limits number of negative power prices. Depending on the power region, this can lead to an overall future increase or reduction in the number of negative power prices.

The subsidy schemes result in less pronounced negative power prices in Sweden in 2040 compared to some Central/Southern European countries. This is likely caused by the significant amounts of reservoir hydro power in Sweden and Norway, which contributes to power balancing.

1. Scope & methodology

This report has been produced by Ea Energy Analyses A/S for Energiforsk as part of the multidisciplinary research project North European Energy Perspective Project (NEPP), which examines the development of Sweden's energy system in a Nordic and European context. The research in NEPP is conducted by researchers and analysts in close collaboration with stakeholders in the energy market.

In a separate part of the NEPP project, carried out in 2024, it has been investigated how the Swedish electricity system could develop up towards 2035 and 2045 given different scenarios for electricity demand and considering whether investments are made new nuclear power or not.[1] The analysis in this study builds on one of the scenarios developed in 2024.

This study centres around future subsidy schemes for non-fossil fuel generators in a European context. The Paris Agreement, the EU's Green Deal, and Sweden's national decarbonization pathway are collectively shifting the focus toward non-fossil fuel generators as the fundamental pillars of the energy system. However, renewable energy generators and nuclear power plants demonstrate high investment costs (and low variable costs) which expose them to revenue risks in the electricity market. To provide long-term support and de-risk the investment in clean energy resources, different tools are available, such as Feed-in

[1] Ea Energy analyses (2024): "European Power System Scenarios with a focus on Sweden". Prepared for Energiforsk as part of the NEPP project (slide report).

Tariffs (FITs), feed-in premiums (FIPs), Guarantee of Origin (GOs), Power Purchase Agreements (PPAs), and Contracts for Difference (CfDs). Contracts for Difference will most likely become the main tool for direct government price support and derisking schemes for new investments in renewables and nuclear power within the EU.[2]

The NEPP project functions as a research cluster and the activities aim to:

- Increase knowledge of the short-term and long-term development of the energy system at national, regional and local level.
- Contribute to underpinning energy policy decisions nationally and internationally.
- Contribute to knowledge that can be used as a basis for decisions and long-term investments in the energy sector.
- Contribute to strengthening research collaboration and knowledge transfer between researchers in Sweden, the Nordic region, and Europe.1

In March 2023, the European Union (EU) proposed a reform of the electricity market design. This reform includes rules for support for non-fossil fuel power generation based on two-way *Contracts for Differences* (CfDs). Two-way CfDs are contracts signed between a public entity and a power generating facility operator that provide at the same time a minimum remuneration protection for the electricity company, when the market price is below a strike price, and a limit to excess remuneration, when the market price is above the strike price. The aim of CfDs is accelerate the deployment of renewables and nuclear energy while at the same time reducing price volatility and shielding consumers from price spikes.

The EU market design proposal allows some flexibility to each member state in terms of the design of the CfDs, provided that CfDs are designed to maintain incentives for power generation facilities to operate efficiently and participate actively in the electricity markets. Conventional CfDs provide a revenue guarantee for low carbon generators, enhancing long-term stability for both producers and consumers. However, this might disrupt market dynamics by reducing market incentives. To address this issue, ENTSO-E and other entities propose decoupling CfD remuneration from power generation by instead applying e.g. financial CfDs or capability-based CfDs, where the support is independent of the actual plant output.

In a previous analysis within the NEPP project, CfDs and alternative support schemes have been analysed from a theoretical perspective.[3] As such, the previous analysis discussed different design choices of subsidy schemes in the form of CfDs, such as strike price, technology neutrality, and location specifications. The previous analysis also provided overall guidance on how a technological neutral CfD tender could be designed.

[2] Ea Energy analyses (2024): "Contracts for Difference (CfD) in the Swedish Electricity Market". Prepared for Energiforsk as part of the NEPP project. https://energiforsk.se/media/33171/2024-991-contracts-for-difference-cfd-in-the-swedish-electricity-market.pdf

[3] Ea Energy analyses (2024): "Contracts for Difference (CfD) in the Swedish Electricity Market". Prepared for Energiforsk as part of the NEPP project. https://energiforsk.se/media/33171/2024-991-contracts-for-difference-cfd-in-the-swedish-electricity-market.pdf

The current analysis takes things a step further than theory and models different potential subsidy schemes in the European energy system. The aim of the study is to:

- *Analyse how different subsidy schemes can impact the future power prices and the power generation in Northern Europe with a focus on Sweden.*

The text box on the next page provides background information for the study, by explaining different underlying factors and market implications that can lead to negative power prices[4].

[4] Under market evolution and structural dynamics, factors that can dampen the formation of negative power prices are also outlined

Negative Electricity Prices: Underlying factors and market implications
Negative electricity prices typically arise when inflexible generation coincides with low demand, causing supply to exceed demand in the spot market. Negative prices only occur if all zero or positive-price bidders are curtailed. While this is a signal of market functioning, a range of factors beyond the spot price contribute to the occurrence of negative prices.

Remuneration outside the spot market

- **Contracts for Difference (CfDs):** Provide a guaranteed price for the electricity produced: If the market price for electricity is lower than the agreed-upon price, the government pays the difference to the generator. Conversely, if the market price is higher, the generator pays the difference back to the government. Depending on the design of the CfD this may decouple producer revenues from spot prices
- **Feed-in Tariffs (FiTs):** Guarantee a fixed price per MWh regardless of market conditions, fully decoupling producer revenues from spot price.
- **Feed-in Premiums (FiPs):** Provide a fixed subsidy per MWh on top of the market price; if the premium is large, it may incentivize occurrence of negative prices.
- **Power Purchase Agreements (PPAs):** Some PPAs, often "pay-as-generated," may incentivize generators to produce, irrespective of spot prices.
- **Guarantees of Origin (GOs):** Create an additional revenue stream, often functioning as a FiP. GO prices can reach €5–8/MWh.
- **Net metering:** Common for small-scale PV, allows producers to offset consumption with generation, ignoring hourly price signals fully or partially.
- **Ancillary Services:** Some generators receive remuneration from the system operator to remain online to provide ancillary services, regardless of the price signals in day-ahead market

Technical and economic constraints
Some generators lack the flexibility to reduce output even when prices are negative:

- **RE Technologies:** Many small-scale PV and older wind turbines are not equipped for automated curtailment.
- **Thermal Plants:** High start-up costs and ramping limitations make thermal generation economically irrational to shut down for short periods.

While persistent or prolonged negative price periods can justify flexibility investments, short-term events often do not.

Market evolution and structural dynamics

- **Growing renewable penetration:** More RE capacity increases the risk of surplus generation during low demand periods, potentially raising the frequency of negative prices.
- **Electrification and flexible demand*:** Expansion of electric heating, transport, and power-to-X (PtX) introduces more flexible load into the system. Over time, this should reduce price volatility and absorb excess generation.
- **Consumer response to price signals*:** Persistently negative prices can incentivize flexible consumption technologies (e.g., electric boilers), which may act as a natural cap on the frequency and depth of negative pricing events. However, consumer responsiveness to price signals is often limited by electricity tariffs and taxes (often non-dynamic), reducing demand-side flexibility.

*These factors can dampen the formation of negative power prices.

1.1. Modelling tool

The Balmorel model is applied, which is a fundamental partial-equilibrium model finding least-cost solutions based on assumptions such as the development of fuel prices, demand development, technology costs and characteristics, renewable resources, and other essential parameters (see Figure 1).

Figure 1. The Balmorel energy system model.

The model version applied covers the majority of Europe including the Nordic countries, the Baltic countries, Germany, Poland, The Czech Republic, Austria, Luxembourg, Italy, Switzerland, France, Belgium, The Netherlands, Great Britain, Spain and Portugal.

The Balmorel model is based on perfect foresight and simulates the European day-ahead market. As such, the model does not reflect the intra-day market or the regulating power markets, responding to imperfect forecasts of power generation from variable renewable energy sources (wind & solar PV etc.), and unforeseen outages of power and transmission units etc,

A more detailed description of the Balmorel model can be found at: https://www.ea-energianalyse.dk/wp-content/uploads/2020/06/Balmorel_UserGuide.pdf

All economic data in the report are given in price index 2024 (EUR24).

1.2. Modelling of European subsidy schemes

Subsidy schemes for the various RES & nuclear electricity generation technologies (onshore wind, offshore wind, solar PV, hydro, and nuclear etc.) exist in many different forms and vary across the European countries. Modelling all the specific subsidy schemes in each of the individual countries would thus require a comprehensive data research, which is beyond the scope of this project. Against this background, the subsidy schemes in Europe are modelled based on central sources and own assumptions, where generic subsidy levels are applied see Table 1).

Table 1. Subsidy levels implemented in the model.

	Description	The category represents...	Subsidy level (€/MWh-e)
MaxSub	Max subsidy level	Generation units receiving high feed-in-tariffs (FITs) or under conventional contracts for difference (CfD), which will produce regardless of the power price in the market. The subsidy level is equal to the current price floor in European markets.	500
HSub	High subsidy level	Units receiving high feed-in premium, i.e. subsidy on top of the given power price in the market.	75
MSub	Medium subsidy level	Units receiving medium feed-in premium, i.e. subsidy on top of the given power price in the market.	25
LSub	Low subsidy level	Units receiving only guarantees of origin (GO).	7*
NoSub	No subsidy	Units receiving no subsidies or GOs.	0

*The assumed GO-subsidy level is based on a forecasted average of GO prices for solar and wind in the range 5-8 €/MWh towards 2030 (https://futureenergygo.com/the-rise-of-guarantees-of-origin/).

The focus of the study is to analyse how different subsidy schemes can impact power prices, and particularly the formation of negative prices. In this perspective, it is most important to model subsidies on generation technologies that are typically dispatched even when power prices are very low or negative. This comprises i.e. technologies with very low marginal operation costs: wind power, solar PV, hydro power, and nuclear power; and not biomass/biogas fired generation technologies. Moreover, model run times become prohibitively long if including different subsidy levels for biomass/biogas fired generation technologies in Europe. Therefore, the subsidies levels shown in Table 1 have only been implemented for wind power, solar PV, hydro power, and nuclear power technologies.

The maximum subsidy level is included to represent units receiving high *feed-in-tariffs or conventional CfDs*, i.e. a guaranteed, above-market price for the electricity they supply to the grid.[5] The units will therefore produce regardless of the electricity price in the market. In the model, all power price subsidies are represented as *price premiums*, i.e. subsidies given on top of the market price. To simulate that these units will produce regardless of the market price, an arbitrary very high subsidy is applied for these units (500 €/MWh).

[5] https://www.investopedia.com/terms/f/feed-in-tariff.asp

The distribution of existing electricity generation capacities on different subsidy levels is based on CEER (2023)[6], EU Commission (2023)[7], and Wind Energy Europe (2024)[8], supplemented with own assumptions:

- The share of existing capacities in each country receiving maximum subsidy are based on the share of existing capacities receiving feed-in tariffs.
- The shares of existing capacities receiving a high subsidy and a medium subsidy, respectively, are based on the existing capacities in the given countries that receive feed-in premiums. The capacities receiving feed-in premiums are assumed to be distributed evenly (50 % split) on high subsidy (75 €/MWh) and medium subsidy (25 €/MWh).
- The shares of existing capacities receiving a low subsidy (7 €/MWh) are based on the amount of RES capacities on Power Purchase Agreements (PPAs) in the given countries, according to Wind Energy Europe (2024). The idea behind this assumption is that the PPAs are constructed intelligently, i.e. in a way that they do not affect the bids of the given production unit at the electricity market yet the value of guarantee of origins will still incite generators to bit slightly below zero in the day-ahead market.

For the countries where subsidy data in CEER (2023) and EU Commission (2023) are missing, the distribution of existing capacities on different subsidy schemes is generally assumed to be around the same level as typically identified for other countries. However, in some cases, the capacity distribution is adjusted based on Ea's knowledge on subsidy schemes for the individual country. For instance, for Sweden it assumed that most of the existing onshore wind capacity does not receive direct subsidies, but are eligible to receive guarantees of origin (GOs), which can be sold separately from the electricity to provide an additional income stream for the producer.

For all countries, it is assumed that all existing renewable energy sources (RES) and nuclear generation units receive some degree of subsidy, i.e. that they as a minimum can receive guarantees of origin. The assumed distribution of existing capacities on the different subsidy levels is given in Appendix.

Table 1 provides an overview of how the existing RES & nuclear electricity generation capacities are assumed distributed on the different subsidy levels applied in the model.

The subsidy level in Sweden for existing installations is around the same level as for most of the other countries European countries analysed; when it comes to solar PV and offshore wind power (see Table 8 and Table 10 in Appendix). Meanwhile, for onshore wind, the subsidy level in Sweden is very low compared to most of the other countries[9] (see Table 9 in Appendix).

[6] https://www.ceer.eu/wp-content/uploads/2024/04/RES_Status_Review_in_Europe_for_2020-2021.pdf

[7] https://economy-finance.ec.europa.eu/system/files/2023-06/dp187_en_energy%20markets.pdf

[8] https://windeurope.€org/intelligence-platform/product/the-corporate-ppa-tool/#interactive-data

[9] 95 % of existing onshore wind capacities in Sweden are assumed to receive the low subsidy level, while this share is only 18 % on average for all the European countries analysed.

Table 2. Assumed distribution of existing electricity generation capacities on different subsidy levels. Intervals illustrate the variation across countries. The country specific capacity distributions are given in Appendix.

	MaxSub	HSub	MSub	LSub	NoSub
Solar PV	14% - 39%	10% - 34%	10% - 31%	0% - 64%	0%
Wind, Onshore	0% - 100%	0%	0% - 25%	0% - 95%	0%
Wind, Offshore	45% - 65%	18% - 18%	18% - 18%	0% - 20%	0%
Hydro	0%	0%	0%	100%	0%
Nuclear	0%	0%	35%	65%	0%

The modelling of the existing European subsidy schemes has been validated by investigating to which extent electricity prices extracted from the model can replicate actual electricity prices in the market. More specifically, it has been investigated whether a model simulation of the year 2025 with the assumed subsidy levels can generate negative electricity prices of the same magnitude as observed in the power market recently (year 2023-2024). For countries with larger deviations, the capacity distribution on the different subsidy levels has been adjusted within reasonable limits. After a few calibrations, it is found that the model can replicate negative electricity prices of a magnitude comparable to the historical negative electricity prices (see Table 3).

Table 3. Comparison of model and historical data on the occurrence of negative power prices

	Modelled no. of power prices < 1 €/MWh	Modelled no. of power prices < 0 €/MWh	Modelled no. of power prices < -0.4 €/MWh	Modelled no. of power prices < -1 €/MWh	Historical no. of negative power prices (2023-2024)
SE1	1298	1010	483	150	440
SE2	1249	966	371	140	428
SE3	371	357	34	29	415
SE4	369	355	27	23	428
NO1	210	195	11	11	288
NO2	200	187	9	9	190
NO3	770	597	99	64	238
NO4	1210	878	338	125	238
NO5	326	310	42	22	238
DK1	430	402	125	113	290
DK2	362	337	0	0	250
Finland	1117	1048	420	232	470
Germany	504	496	315	276	338
France	192	187	56	38	230
Poland	643	633	427	399	130
UK	203	196	70	70	n/r
The Netherlands	396	392	222	199	375
Luxembourg	192	180	70	55	338
Austria	135	135	48	38	30
Belgium	190	172	57	38	288
Switzerland	163	161	57	43	163
Czech Republic	145	144	46	37	203
Estonia	147	128	19	14	123
Latvia	129	111	14	10	113
Lithuania	152	131	20	15	113
Italy	133	132	67	57	n/r
Spain	570	569	320	267	163
Portugal	563	563	289	256	200

As shown in Table 3, the modelled number of power prices below the vicinity of 0 is very sensitive to whether the threshold level is set to exactly 0, or e,g. -0.4 , -1 or +1 €/MWh. This shows that a large amount of the modelled negative power prices are only just below 0 or just above 0. The power price will in these instances typically be set by wind power/solar PV technologies receiving the low subsidy level, and the power price will correspond to the marginal operation costs of these units: variable O&M costs minus the subsidy.

The exact level of these power prices will be sensitive to the variable O&M cost assumed for the different RES units; and the low subsidy level assumed. Considering the uncertainty on both of these factors, Table 3 shows a satisfactory validation of the models' ability to represent negative power prices.

Finally, it should be noted that weather conditions for the given year can influence the occurrence of negative power prices, e.g. wet/dry year affecting hydro power; and wind conditions affecting wind power generation. The model applied is based on a consistent weather data set for a representative year (2014), while the historical data are extracted for 2023-2024. Therefore, deviations in the formation of negative power prices are expected in this comparison.

1.3. Scenarios

To analyse the potential power price effects of different subsidy schemes, four scenarios have been set up. The scenarios vary in terms of how new RES & nuclear capacities are assumed subsidised. In this regard, new capacities are defined as capacities built after 2025. The scenarios analysed are described in Table 4.

Table 4. Scenarios analysed.

<table>
<tr><th>Scenario</th><th>Rest of Europe (other than Sweden)</th><th>Nuclear in Sweden (NUC)</th></tr>
<tr><td>No_Subsidy</td><td colspan="2">A reference scenario where no subsidies on power generation are assumed.</td></tr>
<tr><td>High_Subsidies</td><td rowspan="2">New RES & nuclear capacities in the rest of Europe receive same subsidy schemes as existing installation.</td><td>New Swedish nuclear capacities receive the maximum subsidy level.</td></tr>
<tr><td>High_Subsidies_Low_for_NUC</td><td>New Swedish nuclear capacities are covered by an intelligent subsidy scheme with a minimal power generation subsidy.*</td></tr>
<tr><td>Low_Subsidies</td><td rowspan="2">For new RES & nuclear technologies in the rest of Europe: 50 % reduction in the capacity share receiving significant power generation subsidies (max/high/medium subsidy level); compared to existing units. The remaining units receive are covered by an intelligent subsidy scheme with a minimal power generation subsidy.*</td><td>New Swedish nuclear capacities receive intelligent subsidy schemes with no or minimal price distortion, for example through a financial or capability based CfD *</td></tr>
<tr><td>Low_Subsidies_High_for_NUC</td><td>New Swedish nuclear capacities receive the maximum subsidy level, for example a conventional CfD.</td></tr>
</table>

*In the model, the intelligent subsidy is modelled as a low electricity price subsidy corresponding to the guarantees of origin (7 €/MWh assumed). The main economic incentive for the technologies is instead assumed given in other forms than on power generation (e.g. as subsidies on technology investments).
**35 % on medium subsidy, 65 % on low subsidy (see also the Appendix).
New RES & nuclear capacities are defined as installations built after 2025.

1.4. The modelled energy system

The Swedish energy system is modelled in integration with the interconnected European energy system[10]. The different subsidy scenarios are applied to a given capacity development, which has been modelled based on economic optimization of investments and operation, using inputs such as policies, development in demand and fuel prices, technology costs and characteristics, renewable energy resources, and other essential parameters.

An overall assumption is that Europe pursues a net zero energy system (or close to net zero) in 2050, which drives energy demand and supply. A significant electrification is assumed in Europe both directly with electric vehicles in the transport sector, heat pumps/electric boilers in district heating and individual heating, and indirectly in the form of power-to-X to supply green fuels to end-use applications that are difficult to electrify directly (e.g. aviation & shipping). The total European electricity demand is thus assumed to increase significantly, from 2025 to 2045 (see Figure 2).

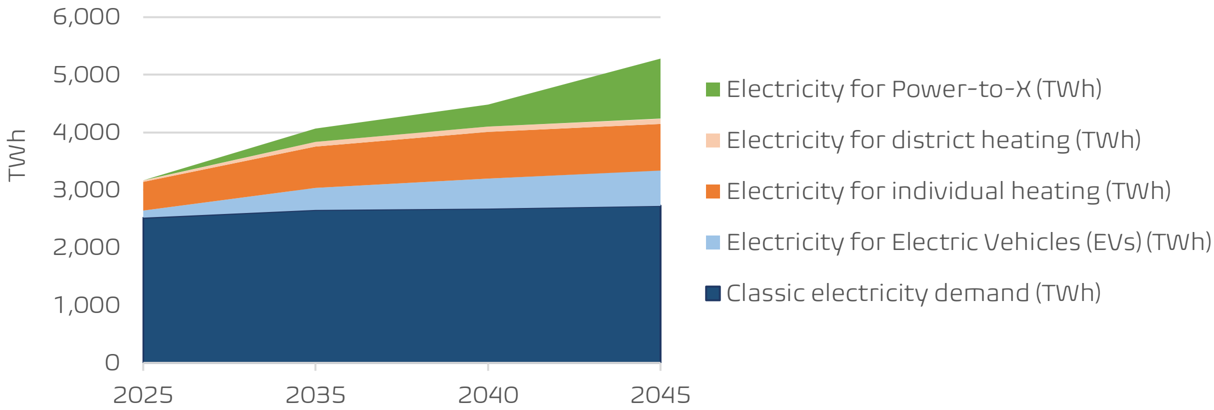


Figure 2. Total electricity demand in the modelled European countries towards 2045[11].

Both electricity for power-to-x, electric vehicles, individual heating, district heating, and part of the classic electricity demand - is to some extent modelled as being flexible (see Table 5). Hereof, power-to-x, comprises a significant electricity demand and is at the same time particularly flexible, through the use of modelled hydrogen storage investments. The total European hydrogen storage capacity investment in 2040 in the modelled scenario thus corresponds to around 250 hours of average hydrogen demand.

[10] The model covers the majority of Europe including the Nordic countries, the Baltic countries, Germany, Poland, The Czech Republic, Austria, Luxembourg, Italy, Switzerland, France, Belgium, The Netherlands, Great Britain, Spain and Portugal.

[11] Regarding, power-to-x, a part of the European demand for liquid green fuels is in the scenarios covered by fuel import on the global market; and part of the hydrogen demand is also comprised by import (approx. 55 % in 2040 in the scenarios). In the model, hydrogen import via pipelines from Africa is allowed to a certain extent, as well as a more costly option of import through shipping. As such, the assumed development in the European demand for power-to-X-fuels is higher than indicated on Figure 2.

Table 5. The applied modelling of different electricity demand categories.

Demand category	Description	Flexibility	Associated cost
Classic	Classic electricity demand mainly for households, the industry and service sector. Contains demand types not explicitly covered under the other categories.	The share of the classic demand that is flexible is assumed to increase gradually from 0% in 2020 to 3% in 2030 and 10% in 2050 (pct. of average hourly demand). The flexible demand can be moved in time with up to 2 hours by paying an activation price. This demand includes industry that also have flexibility to move production to low price hours.	Two main cost levels. 50% of flexibility activated at a cost of 15 €/MWh, 50% of flexibility activated at a cost of 30 €/MWh. This means that flexibility will be activated at this price difference.
Electric vehicles	Demand includes all electricity for road transport. Initial profile is based on charging patterns matching transport demand (Estimated for individual countries based on empirical data from Norway)	The share of vehicles participating in flexible charging is assumed to increase gradually from 20% in 2020 to 35% in 2030 and 65% in 2050. This demand can move the planned charging by up to 4 hours. Thus, the modelling accounts for smart charging but not Vehicle-to-grid solutions. The EV flexibility considers driving patterns and ready-to-drive constraints.	Flexibility activated at a cost of 15 €/MWh.
Individual heating	Includes electricity consumption for space heating in buildings, which is modelled as heat demand. The demand is supplied by heat pumps, direct heating, and electric boilers.	Flexible heat generation by adjustments to initial demand profile. Approximately 35 % of the heat demand in 2030 increasing is considered flexible; increasing gradually to 60 % in 2050. The flexible demand can be moved 2 hours.	Flexibility activated at a cost of 10 €/MWh.
District heating	Electricity for district heating is based on model optimization. Heat pumps, storage and electric boilers are among the options to supply the district heating demand. Other options are fuel-based district heating generation from heat only boilers or CHP.	Flexibility consists of the option to fulfill the heat demand by electricity or other heat generation, depending on the power prices	Investment and operational cost for electric boilers or heat pumps included. Using alternative options for heat generation yields additional cost.
Power-to-X	Electricity for PtX is included based on the demand for e-gasses, e-liquids and hydrogen. Modelled as electricity consuming generation facilities (electrolysers).	Model optimised hydrogen storages can be installed to enable flexible use of electrolysers, while demand is modelled constant.	Investment and operational cost for electrolysers and hydrogen storages included. If profitable, storages can be installed to move portions of the demand, hence providing further flexibility to the system.

To meet the demand increase, the power generation in Europe is also increasing considerably towards 2045 (see Figure 3). As shown, the generation increase is mainly met by wind power and solar PV.

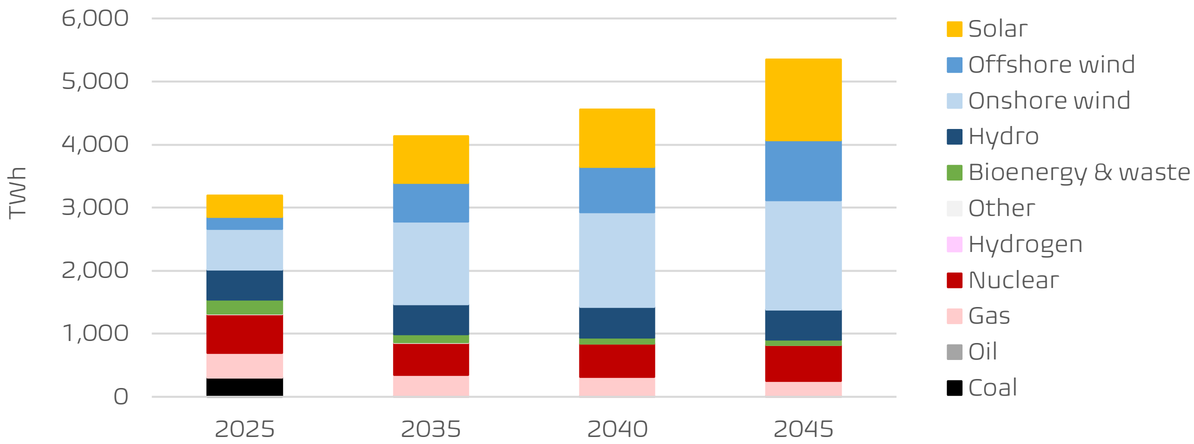


Figure 3. Total power generation in the modelled European countries towards 2045.

As such, the share of variable renewable energy sources (mainly wind & solar) in the power mix is increased to around 70-75 % in 2040-2045. This development can be expected to imply larger occurrence of situations where technologies with low marginal operation costs - wind power, solar PV, and nuclear power - will be setting the power price, as marginal suppliers. If subsidies on power generation are put on these non-fossil generators, it could potentially result in more outspoken formation of negative power prices.

Across the scenarios, all capacities are identical and are based on a scenario from the NEPP project with high electricity demand[12] and an assumed expansion with nuclear power of 2.5 GW by 2040 and 6.0 GW by 2045. (the scenario HighDemand_NUC). The Swedish power capacity development in the scenario is shown on Figure 4.

[12] High classic electricity demand and high electricity demand for individual heating, electric vehicles, and power-to-X-production.

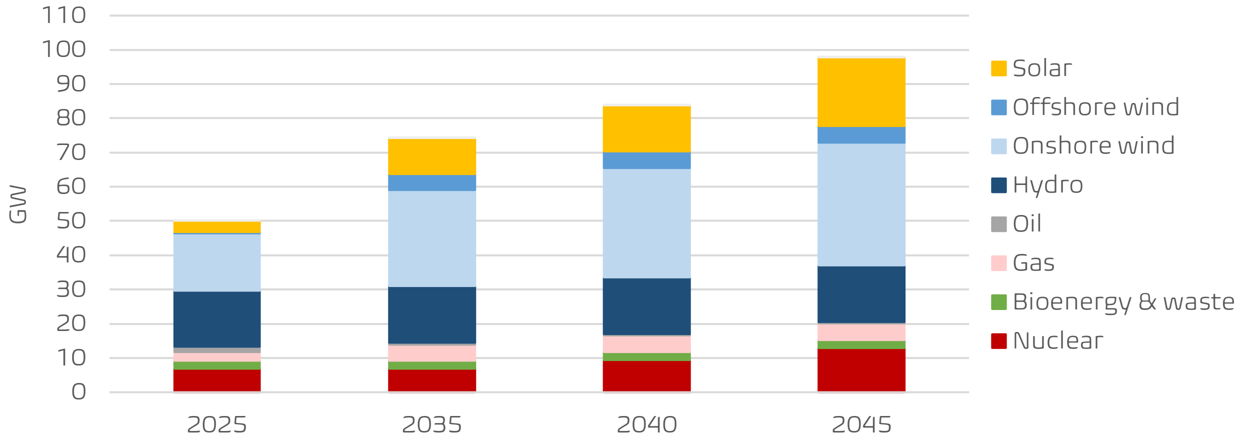


Figure 4. Swedish power capacity development for the scenario HighDemand_NUC, which is used as basis for the scenarios with different subsidy schemes.

As such, the applied modelling approach does not investigate to which extent subsidy schemes can impact investments in power generation, e.g. potentially facilitate higher investments in RES and nuclear. The analyses focus on how different subsidy schemes can impact the operation of the energy system, i.e. the unit commitment and economic dispatch. The dispatch of the energy system is modelled with hourly time resolution.

2. Results

This chapter examines how future subsidy schemes could affect power generation and power prices in Northern Europe, focusing primarily on Sweden.

2.1. Impacts on power generation

Figure 5 show the power generation in 2040 in the modelled European system for the scenarios, No_Subsidy, Low_subsidies and High_subsidies. The same type of illustration is shown for Sweden on Figure 6. It can be seen that **the power generation subsidies on wind power, solar PV, nuclear power, and hydro power only marginally change the dispatch of the power system**; both for the European system as a whole, and for the case of Sweden**.** The reason is that the subsidized technologies have low marginal operation costs and are thus generally dispatched among the first options in the merit-order; also without power generation subsidies. This also means that e.g. fuel consumption and CO_2 emissions are only marginally affected by the subsidy schemes[13].

[13] The subsidies reduce the modelled European CO_2 emissions in 2040 with less than 0.1 %.

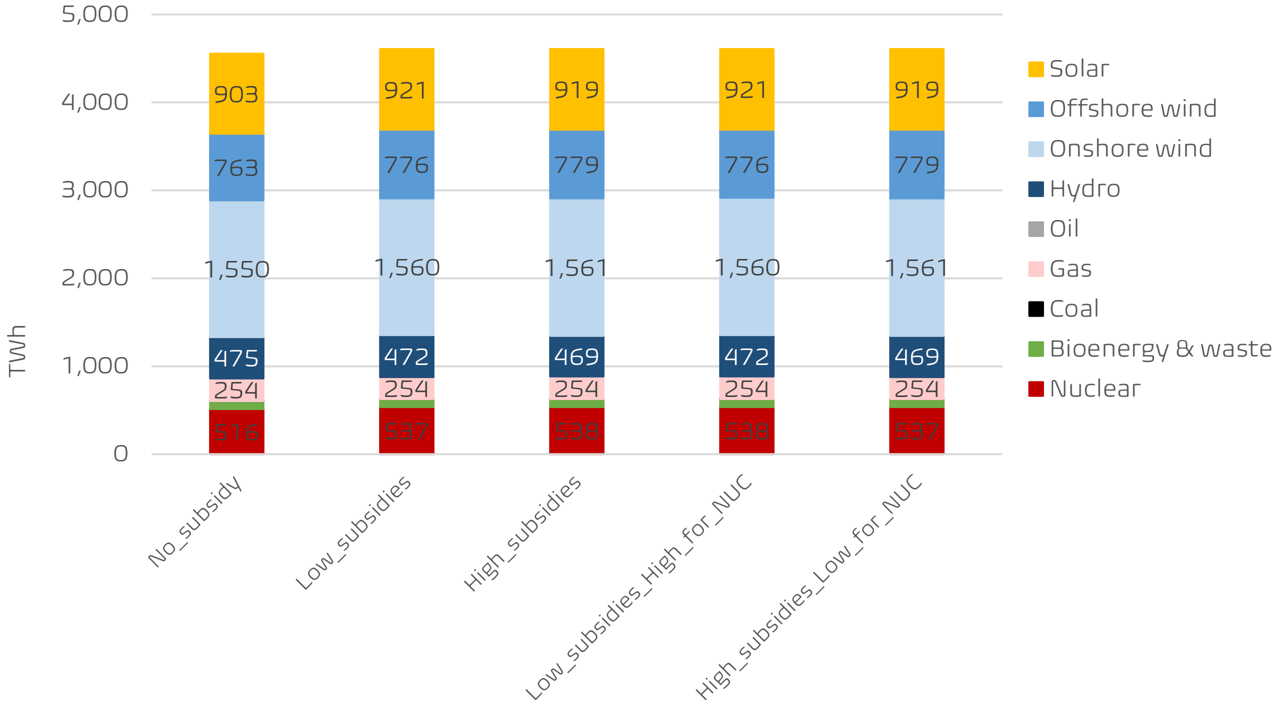


Figure 5. Power generation in 2040 in the modelled European energy system for the scenarios No_Subsidy, Low_subsidies and High_subsidies (numbers are rounded).

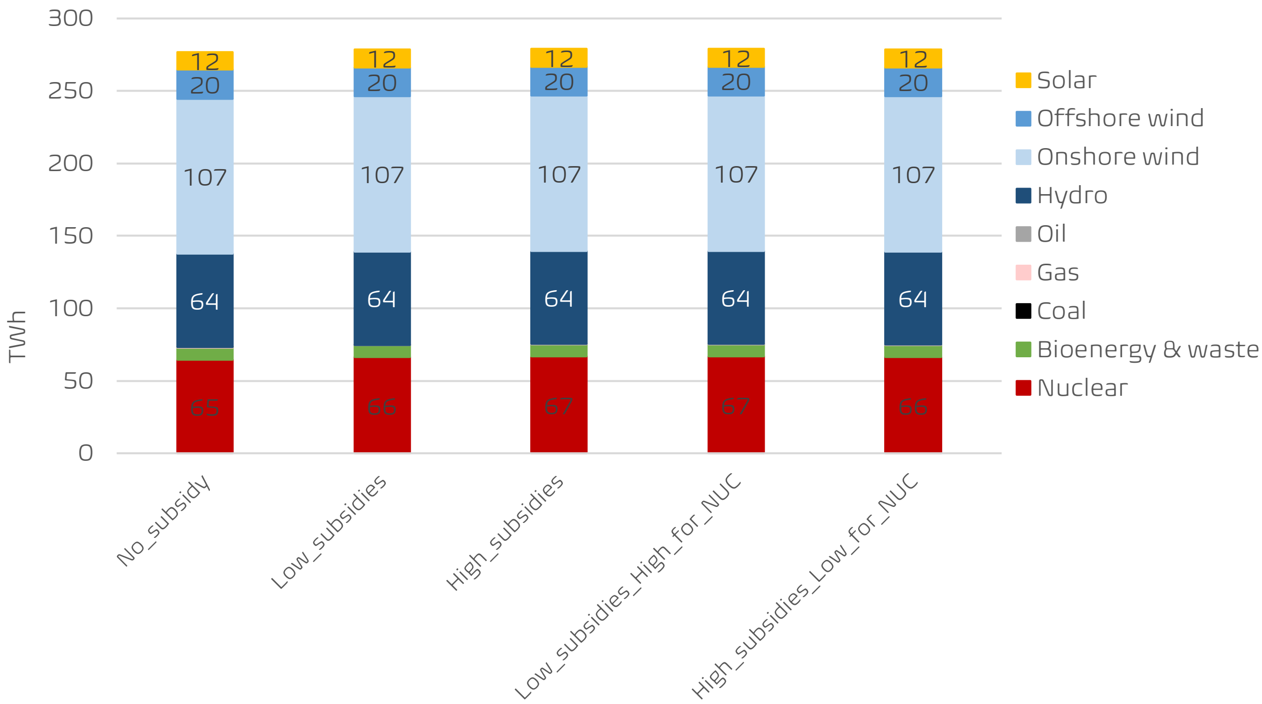


Figure 6. Power generation in 2040 in Sweden for the scenarios No_Subsidy, Low_subsidies and High_subsidies (numbers are rounded).

For the further investigation of the marginal effects, Figure 7 zooms in on the changes in the Swedish electricity generation due the subsidies. As shown, **the Swedish nuclear power generation in 2040 is increased by 1.7-2.1 TWh because of the subsidy schemes. This corresponds to an increase of approx. 9 % on the new nuclear power unit** (the assumed 2.5 GW unit) and an increase of approx. 3 % compared to the total Swedish nuclear power generation in 2040. This illustrates that the subsidies can lead to some shifts between different low OPEX-based technologies. This reflects differences in both the structure of subsidy schemes and the variable operating costs associated with each technology.

The increase is highest for the two scenarios with high subsidy levels for new nuclear in Sweden (in 2040 this comprises the buildout of 2.5 GW new nuclear capacity).

Additionally, **the subsidy schemes lead to modest increases (up to 0.1 TWh) in onshore wind power and solar PV based electricity generation in Sweden**. This is due to reduced curtailment and illustrates that the applied subsidy levels are higher than the modelled variable O&M costs for wind and solar PV.[14] Therefore, in a situation where the solar/wind-based electricity generation would be curtailed in the No_subsidy scenario, it is still attractive for solar/wind power units to produce power in the subsidy scenarios; to the extent that the extra power generation can be absorbed in the system. In the scenarios, there is a modest increase in the electricity consumption in response to the negative power prices.

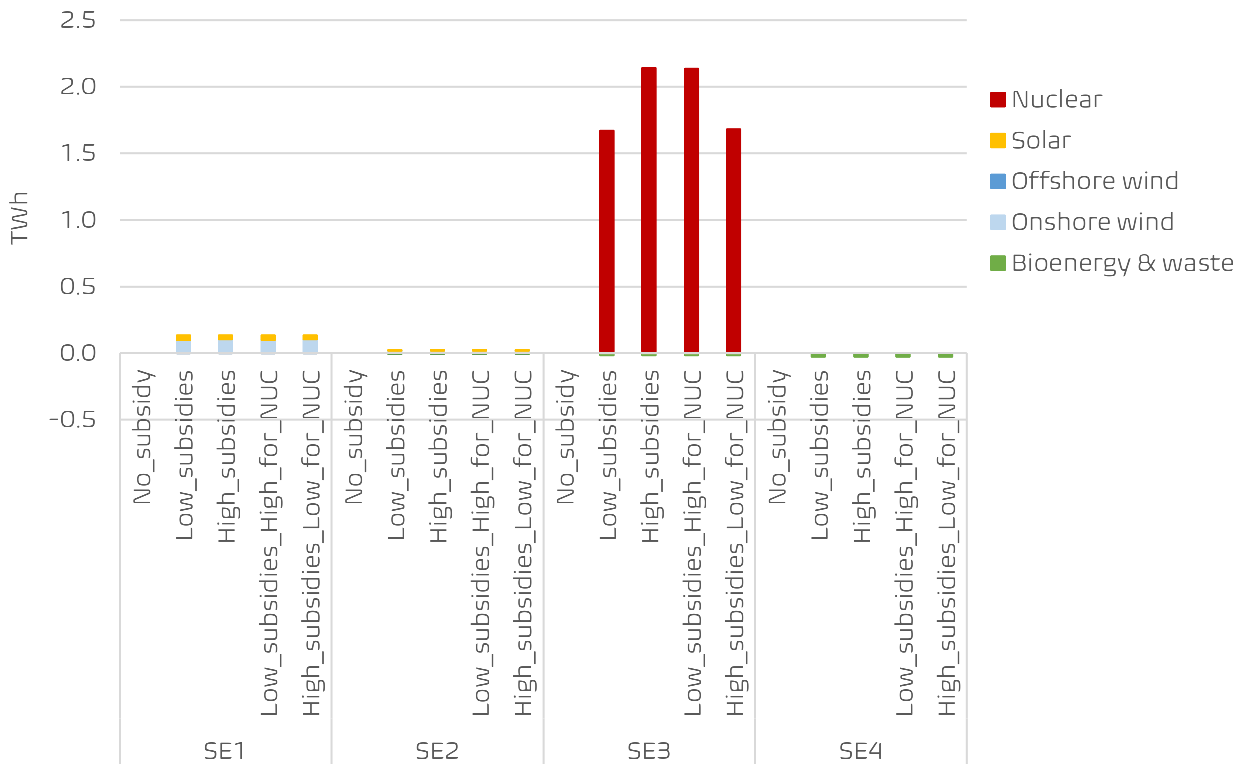


Figure 7. Changes in electricity generation in Sweden in 2040 for scenarios with subsidy schemes compared to the No_subsidy scenario.

[14] 7-500 €/MWh compared to the variable O&M costs of approx. 0-4.5 €/MWh for wind power & solar PV in the model.

2.2. Impacts on power price duration curves

Sweden is currently divided into four electricity price areas: Luleå (SE1), Sundsvall (SE2), Stockholm (SE3) and Malmö (SE4), see Figure 8. Impacts on power prices in Sweden are shown for two of the Swedish power regions, namely:

- SE3, which comprises the largest part of Sweden's electricity demand, and where the nuclear power capacity is concentrated.
- SE1, which has a significant amount of hydro power generation.

The price effects found in SE2 and SE4, are very similar, thus they are provided in the Appendix.

Where relevant, the price impacts are also shown for other European countries.

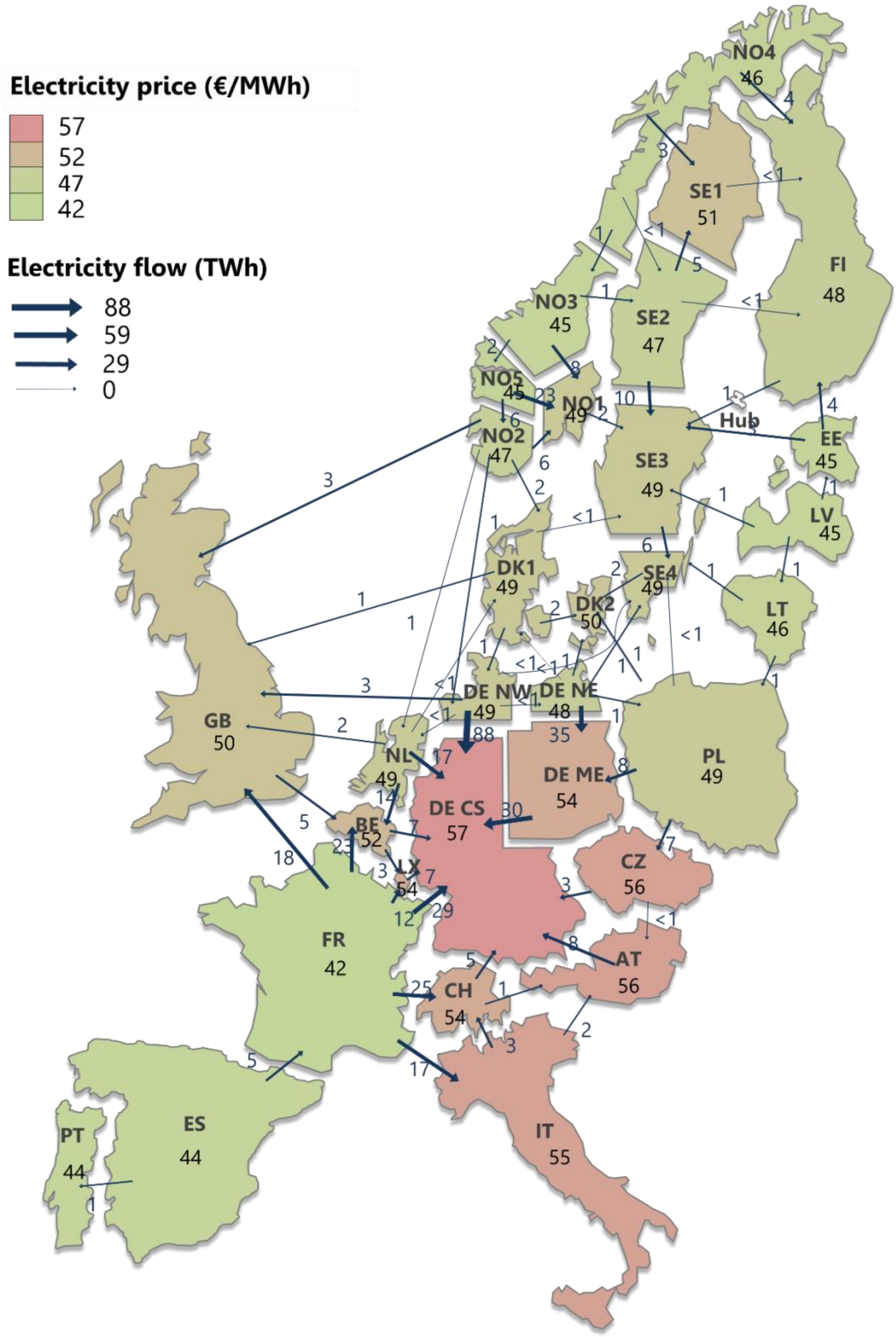


Figure 8. Illustration of the different Swedish power regions, and the modelled transmission connections within Europe. The scenario High_subsidies in 2040 is illustrated as an example. Numbers within the bidding zones represent average whole-sale power prices in the model simulation.

The potential impact that different subsidy schemes can have on future power prices is investigated by observing duration curves as this gives an overview of the aggregated impacts.

The power price duration curves[15] of the scenario High_Subsidies_Low_for_NUC scenario are practically identical to the duration curves for the High_Subsidies scenario. Similarly, the duration curve of the Low_Subsidies_High_for_NUC scenario is practically identical to those of the Low_Subsidies scenario. As such, a **high/low subsidy level for new nuclear power plants in Sweden in 2040 apparently has a negligible effect on the power prices**. The reason is that the amount of new nuclear capacity in Sweden by 2040 is moderate (2.5 GW assumed). Against this background, the duration curves for the scenarios High_Subsidies_Low_for_NUC and Low_Subsidies_High_for_NUC are left out of the figures. The price distorting effect of subsidies on new Swedish nuclear might be larger when observing 2045, where the new nuclear capacity is expected to be larger (potentially approx. 6 GW)

The impact in 2040 on the power price duration curves for the Swedish regions SE3 and SE1 are shown on Figure 9 and Figure 10, respectively.

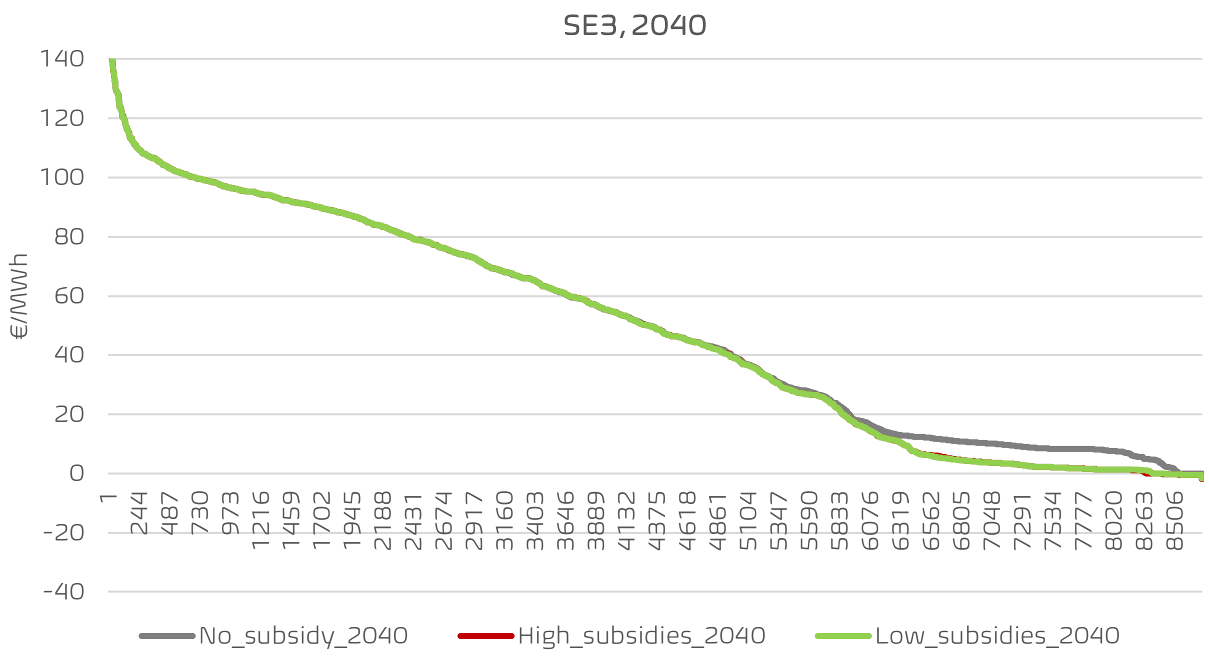


Figure 9. Power price duration curve for SE3 in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

[15] Note: A **power price duration curve** is a graph that shows electricity prices sorted from highest to lowest over a specific period, typically a year. It illustrates how often certain price levels occur and helps assess price volatility and revenue potential for power producers.

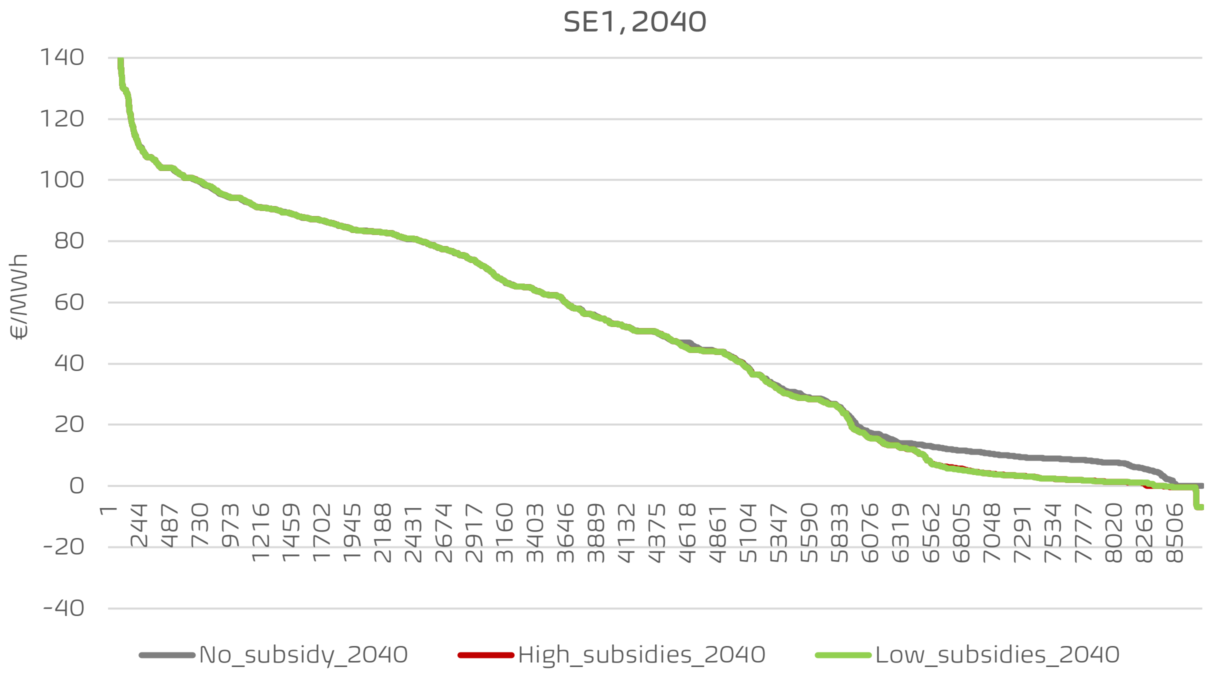


Figure 10. Power price duration curve for SE1 in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

The figures show that for SE1 and SE3 in 2040, for the lower part of the duration curve, the power prices in the subsidy scenarios are some-what lower compared to the scenario without power generation subsidies (No_subsidy scenario). This shows that **the analyzed subsidy schemes will have a moderate distorting effect on the power prices in Sweden**. The results suggest that for Sweden in 2040, the power prices under the high subsidy scheme are practically identical to the power prices under the low subsidy scheme. The results thus suggest that towards 2040, **the high subsidy scheme does not distort prices in Sweden further than the low subsidy scheme**.

Due to the project focus on distortions that can lead to negative prices, the subsidy scenarios only represent subsidies on technologies with very low marginal operation costs: wind power, solar PV, nuclear power (and hydro power) [16]. It is therefore as expected that the price distortion practically only occurs in the low end of the duration curve, where these technologies are marginal and thus the ones setting the power price. In other words, **the subsidies on variable RES and nuclear mainly reduces power prices in periods when demand is low and/or power production from variable RES is high**.

[16] A significant share of the Nordic hydro power capacity is connected to large reservoirs allowing that hydro power generation may to be some extent be shifted in time. Account for the opportunity cost of water, i.e., using water now vs. saving it for potentially higher prices in the future. Though the short run marginal cost is zero or close to zero, the bidding strategy takes into account the opportunity cost of water, i.e., using water now vs. saving it for potentially higher prices in the future

Figure 11 and Figure 12 zoom in on the lower part of the power price duration curve for SE3 and SE1, respectively. The graphs illustrate that the power price is reduced from around 2.5-14 €/MWh in the No_subsidy scenario to around 0-12 €/MWh in the subsidy scenarios:

- The high to medium end of this price section likely represents hours where nuclear power is the marginal production technology, since it corresponds to the modelled marginal operation costs of these production units (11-14.5 €/MWh in fuel cost & variable O&M cost, excl. subsidies).
- The medium to low end of the price section likely represents hours where offshore and onshore wind sets the power price (modelled variable O&M costs of approx. 3-6 €/MWh for offshore wind and 0-4.5 €/MWh for onshore wind[17]).

In this lower part of the duration curves for Sweden, the price reduction from the No_subsidy case to the subsidy scenarios is around 7 €/MWh. As such, this price distortion illustrates the effect of the low subsidy level on nuclear power and a given share of variable renewable energy sources (7 €/MWh representing the assumed future level of guarantees of origin).

The negative power prices observed in the subsidy scenarios in Sweden in 2040, e.g. down to -7 €/MWh e.g. in SE1 and down to -2 €/MWh in SE3 likely represent situations where solar PV and wind power units receiving the low subsidy levels (LSub) are setting the power price:

- Solar PV units are modelled with zero marginal operation costs (zero variable O&M cost[18]) meaning that solar PV units will place bids in on the power market corresponding to the subsidy received, i.e. -7 €/MWh for units receiving the low subsidy level.
- Correspondingly, wind power units will place bids on power market to cover their variable O&M costs (0-6 €/MWh), minus the low subsidy level received (7 €/MWh). As such, they will place bids on the power market of approx. -7 €/MWh to 1 €/MWh, in the high subsidy scenario (with the modelled assumptions).

[17] Based on technology data in Danish Energy Agency (2025): "Generation of Electricity and District heating – Technology descriptions and projections for long-term energy system planning" (https://ens.dk/analyser-og-statistik/teknologikatalog-produktion-af-el-og-fjernvarme).

[18] Based on technology data in Danish Energy Agency (2025): "Generation of Electricity and District heating – Technology descriptions and projections for long-term energy system planning" (https://ens.dk/analyser-og-statistik/teknologikatalog-produktion-af-el-og-fjernvarme).

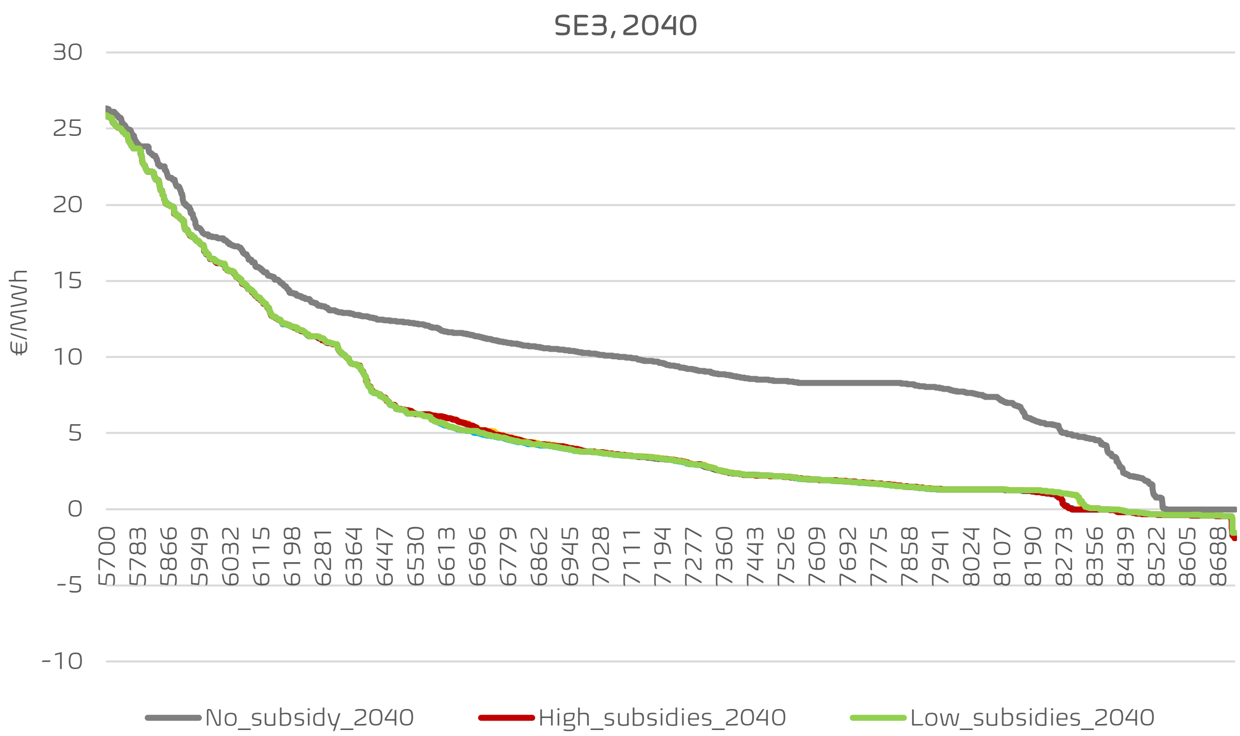


Figure 11. Zooming in on the lower part of the power price duration curve for SE3 in 2040 for different scenarios of future subsidy schemes.

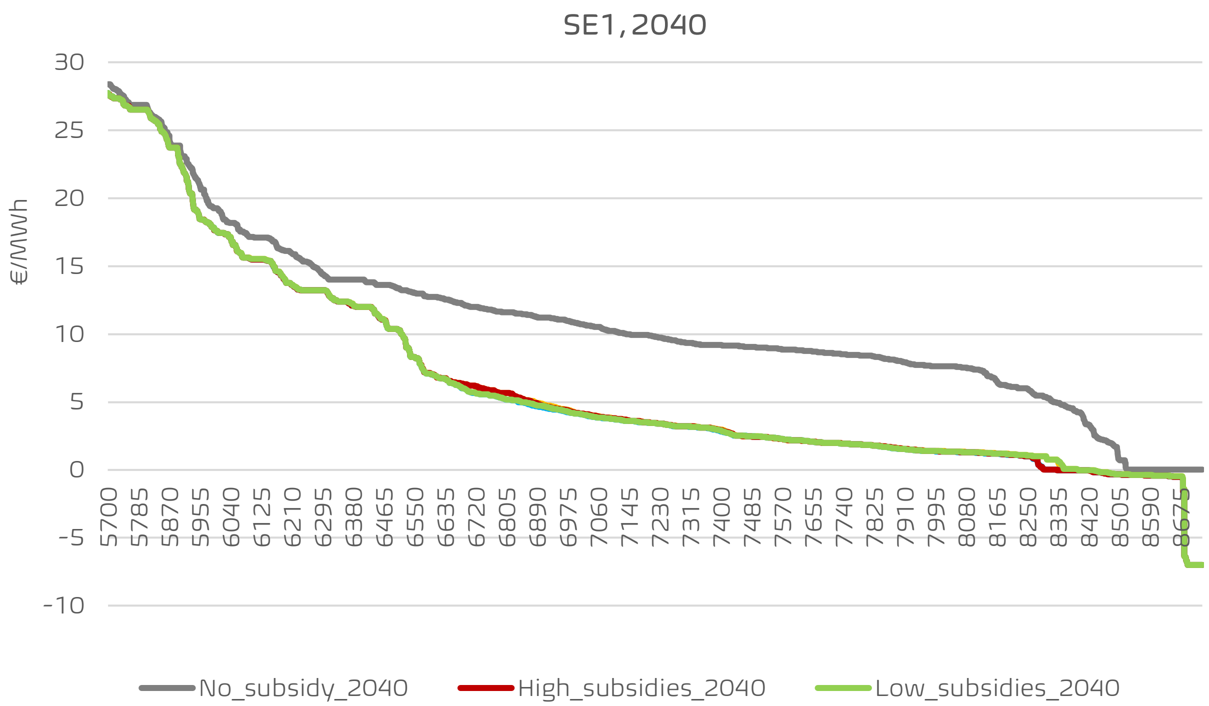


Figure 12. Zooming in on the lower part of the power price duration curve for SE1 in 2040 for different scenarios of future subsidy schemes.

The **results do not suggest a significant occurrence of negative power prices in Sweden in 2040 even in the high subsidy case**. As such, only in very few hours of the year, the modelled results show negative power prices in Sweden in 2040, and in these hours, the power prices are only moderately negative (down to -7 €/MWh in SE1 and down to -2 €/MWh in SE3).

Sweden's significant amounts of reservoir hydro power (see Figure 13) and interconnections with the Norwegian hydro power reservoirs (see also Figure 8) likely contributes to power balancing thereby limiting the occurrence of negative power prices.

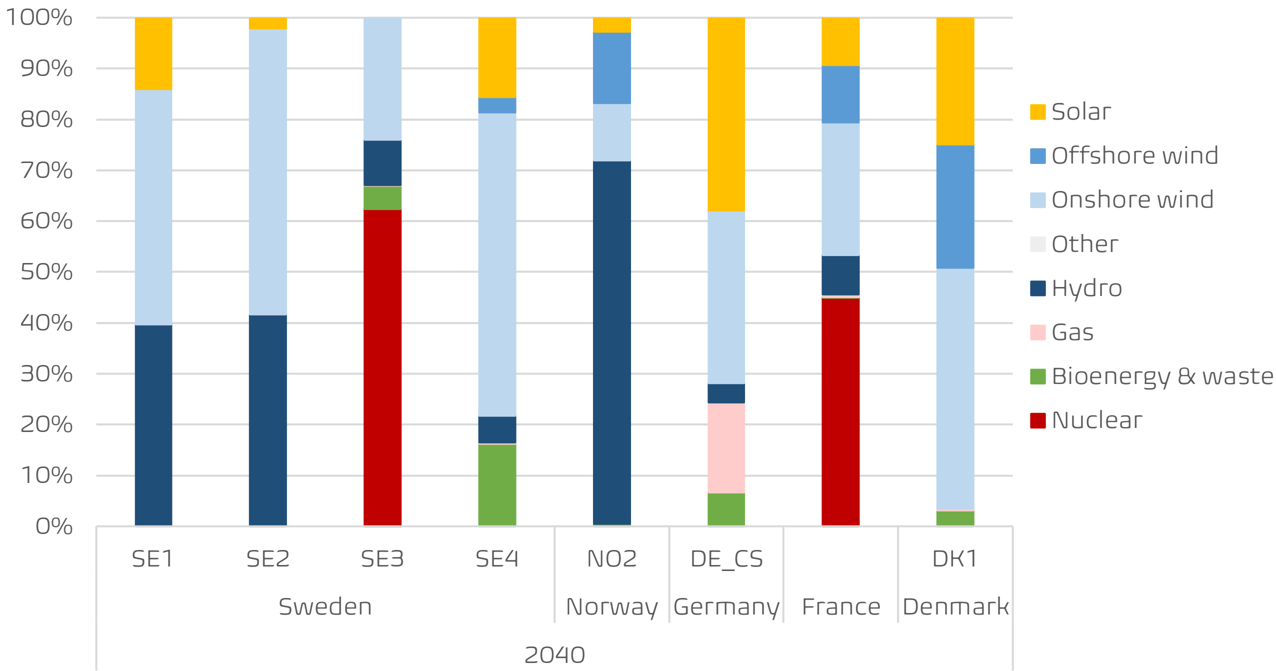


Figure 13. Power generation in 2040 for selected power regions distributed on sources for the High_subsidy scenario. In the model, Germany is divided in four bidding zones. The figures in the graph represent Central and Southern Germany, where most of the German power demand is located.

Similar effects on power prices are identified for other countries in Northern Europe, as illustrated for Finland, NO2 in Norway, and DK1 in Denmark (see Figure 14, Figure 15, and Figure 16).

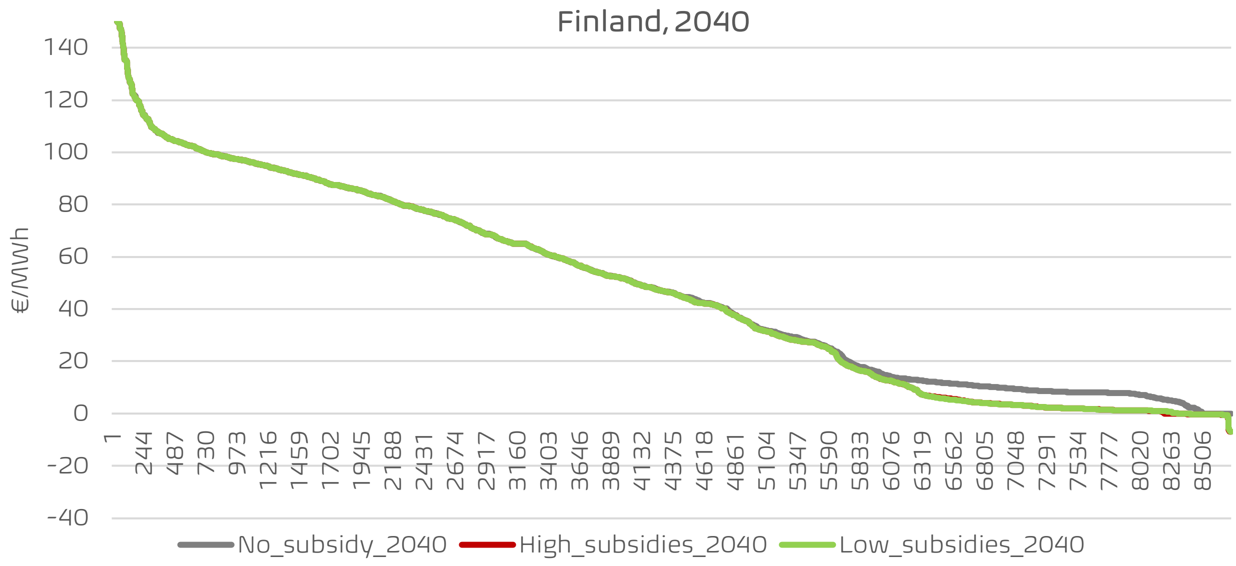


Figure 14. Power price duration curve for Finland in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

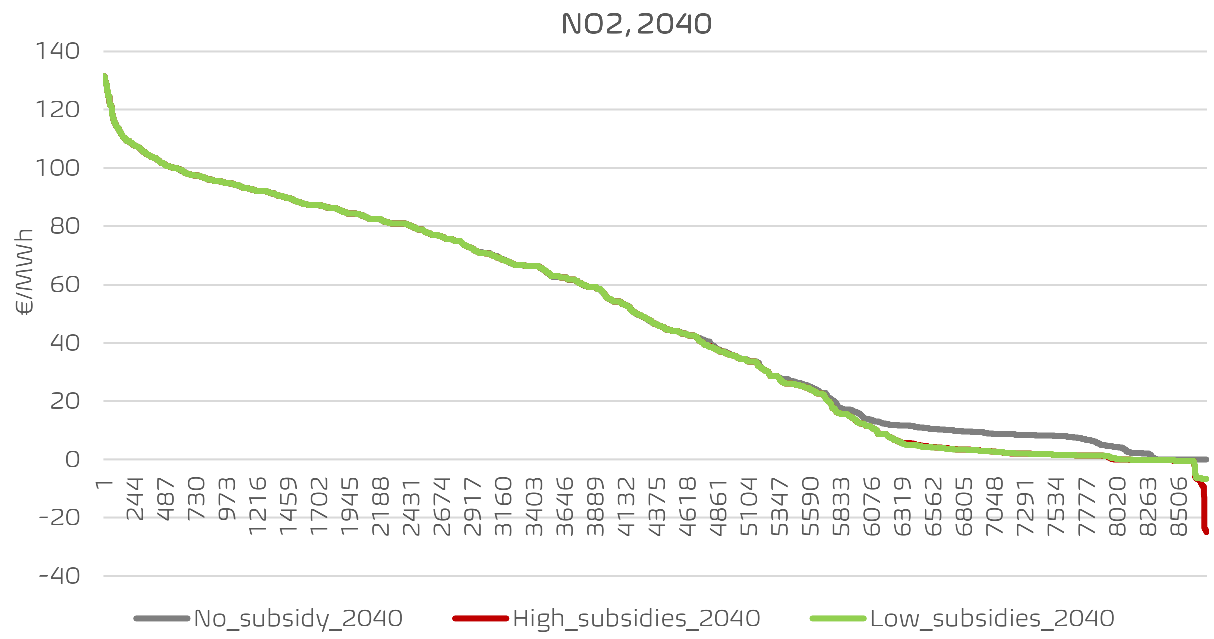


Figure 15. Power price duration curve for NO2 in Norway in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

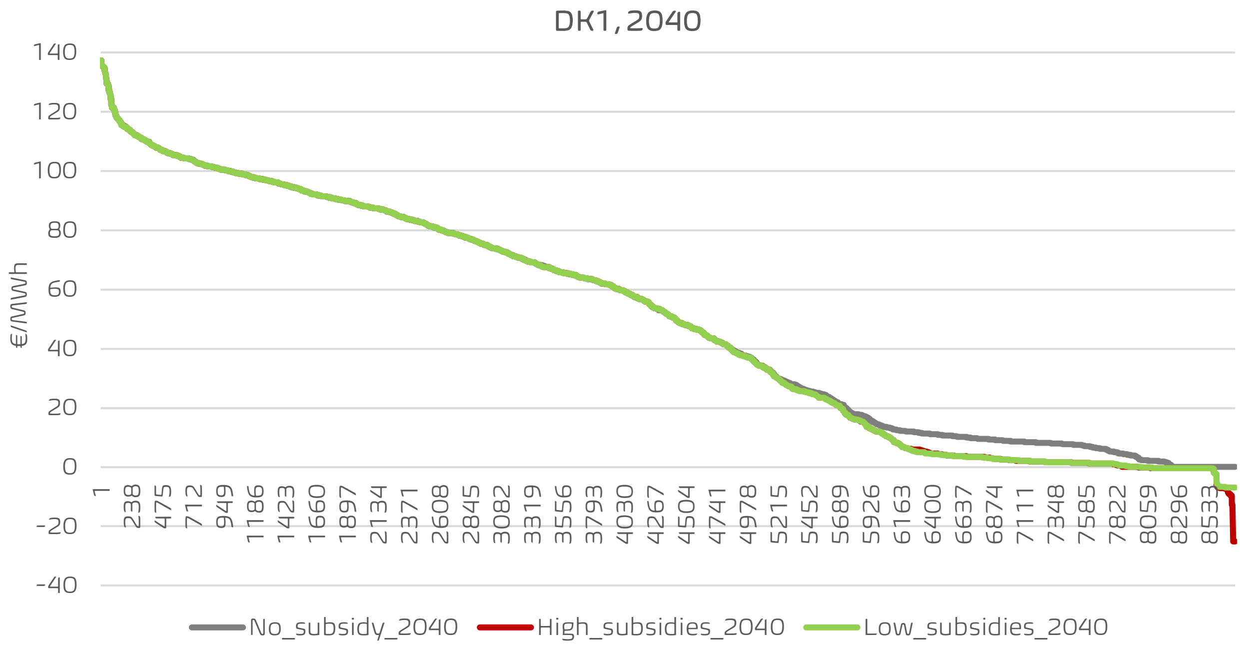


Figure 16. Power price duration curve for DK1 in Denmark in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

For some of the Central/Southern European countries, more outspoken negative power prices are found in the high subsidy scenario. For instance, negative power prices down to -65 €/MWh are identified for Central and Southern Germany[19] (DE_CS) (Figure 17). Part of the reason for the larger impact on power prices in Germany compared to Sweden is likely that onshore wind and solar PV in Germany receive a relatively high level of subsidies, according to the data and assumptions applied[20] (see Table 8 and Table 9 in Appendix). In addition, Germany does not to the same extent as Sweden have access to power balancing provided by hydro power with reservoir capacity.

[19] In the model, Germany is divided into four bidding zones. Most of the German power demand is located in the region Central and Southern Germany (DE_CS).

[20] E.g. 94 % of existing onshore wind in Germany is estimated to receive the maximum subsidy level defined, while in Sweden, this share is 0 % (see Table 9 in Appendix).

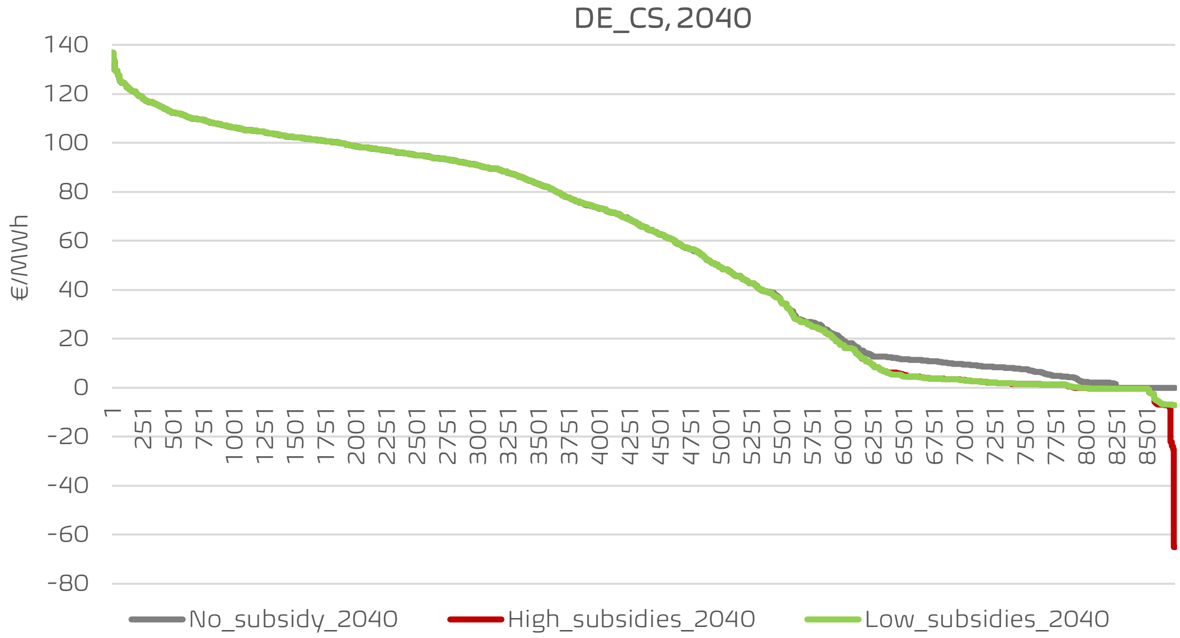


Figure 17. Power price duration curves 2040 for the German power region DE_CS, where the largest part of the electricity demand is concentrated. The scenarios No_subsidy, High_subsidies, and Low_subsidies are shown.

Similarly, for France negative power prices down to -75 €/MWh are identified in the model results for 2040 (see Figure 18). Negative power prices at this level presumably represent situations where the marginal power units are comprised by variable RES units with zero marginal operation costs (solar PV), receiving the assumed medium subsidy level of 75 €/MWh.

The price distortion in hours where nuclear power is the marginal producer (at power prices around 11-14.5 €/MWh) is larger for France compared to the duration curves illustrated for other power regions. This is most likely due to the significant share of nuclear power capacity in France, which is relatively inflexible, combined with the fact that France compared to e.g. Sweden do not have the same access to large hydro power reservoirs for power balancing.

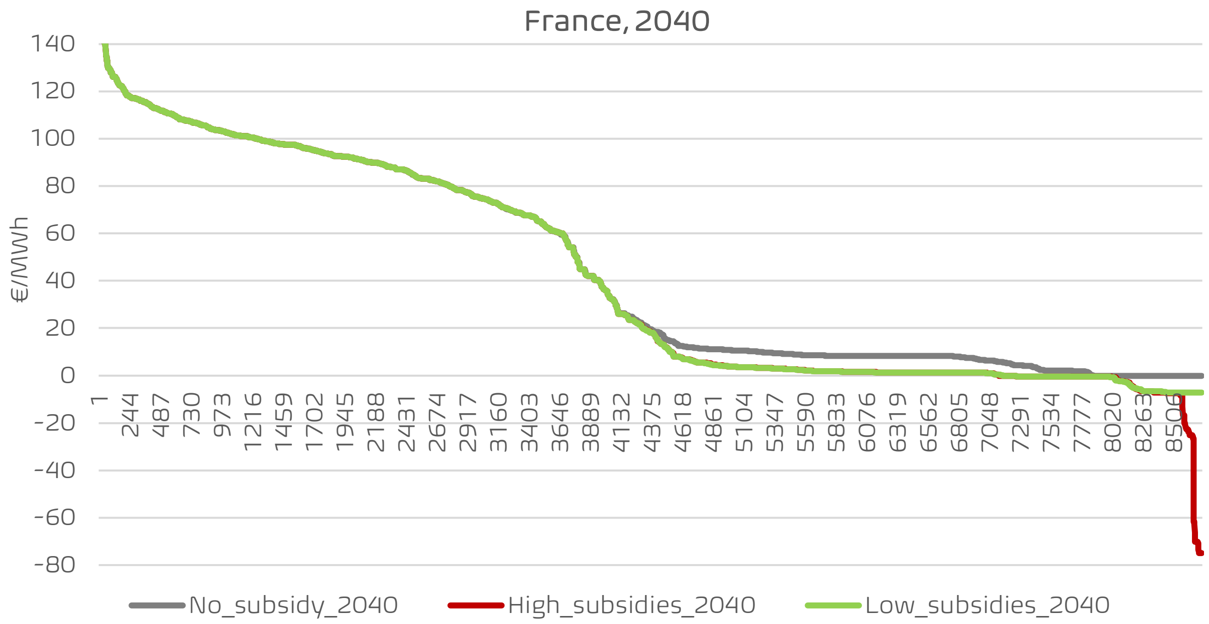


Figure 18. Power price duration curve for France (FR_R) in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

Looking across the different European countries, the model analysis suggests that subsidies on power generation from non-fossil generators reduce power prices. The **power price reduction typically occurs for the lowest part of the power prices over the year, where solar PV, wind power, and nuclear power are setting the price as marginal suppliers**.

For most countries including the North European countries, the price reduction occurs in approximately the lowest 25-30 % part of the price duration curve. For countries such as France, Spain, and Portugal, the price reduction affects the lower 50 % of the power prices over the year.

2.3. Development in occurrence of negative power prices

The number of negative power prices in the different European countries/bidding zones occurring in the modelling of 2025 and the Low_subsidies and High_subsidies scenario in 2040 is illustrated on Figure 19.

As previously illustrated, the number of modelled negative power prices in 2025 is sensitive to factors such as assumed variable O&M costs and subsidy levels. Therefore, the model's ability to reflect historical negative power prices has been validated based on a broader perspective, where different thresholds levels are applied (see section 1.2). Figure 19 is thus only intended used for indicating general trends in the development of negative power prices.

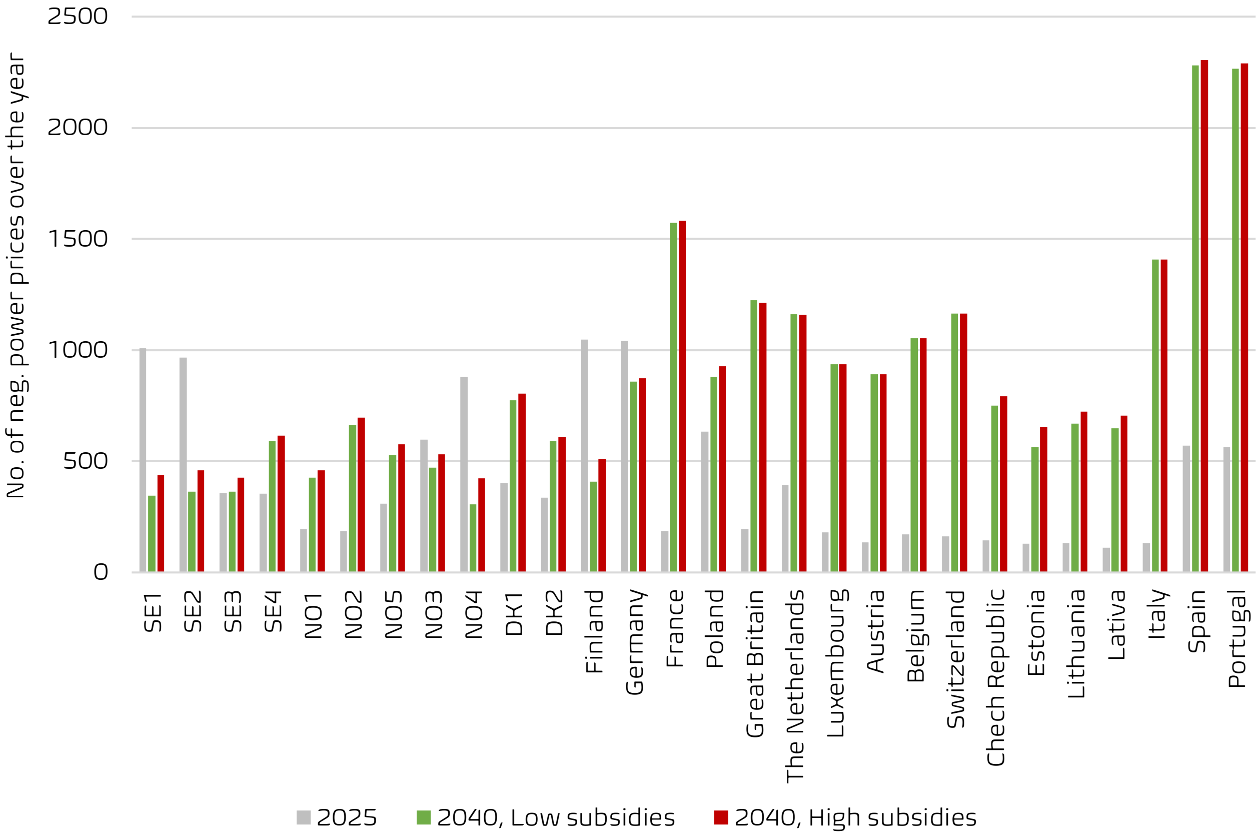


Figure 19. Number of negative power prices (prices below 0 €/MWh) over the year occurring in the modelling of 2025 and the Low_subsidies and High_subsidies scenario in 2040,[21].

The modelled scenarios suggest that **the total number of negative power prices in the European countries covered, is more than doubled from 2025 to 2040.**

The increase in the number of negative power prices towards 2040 is only moderately higher in the High_subsidies scenario compared to in the Low_subsidies scenario (approx 120 % vs. 110 %).

The increasing number of negative power prices toward 2040 reflects the impact of the higher amounts of wind power and solar PV) n the European power mix. This results in more events where wind power and solar PV are the marginal power producers, and where subsidies on these technologies can thus result in negative power prices.

For the case of Sweden, the number of negative power price events is significantly reduced towards 2040 in two of the power regions, SE1 and SE2, while they are increased in SE3 and SE4. A reduction in the formation of negative power prices is also observed in some of the other countries, e.g. in Finland, Germany and some of the Norwegian power regions (NO3 and NO4). This likely illustrates that two key trends have opposite effects on the occurrence of negative power prices:

[21] Germany is modelled as four different power regions to reflect the major bottlenecks in the power system. Since Germany only comprises one bidding zone, a weighted average of the four power regions is made to resemble the number of negative power prices in Germany as a whole.

- On one hand, the share of wind power and solar PV in Europe is increasing in the future, which facilitates more negative power prices, all other things equal.
- On the other hand, the share of flexible electricity demand, e.g. from power-to-x, is also increasing which can contribute to balancing supply and demand and thus limit the number of negative power prices.

The model results likely shows that in some power regions, the increase in power system flexibility has a higher impact than the increased amount of wind power and solar PV in the power mix.

2.4. Impacts on average power prices & capture prices

As illustrated on Figure 22, **the modelled subsidy schemes lead to modest reductions of approx. 2-3 €/MWh on the average whole-sale power prices in Europe**.

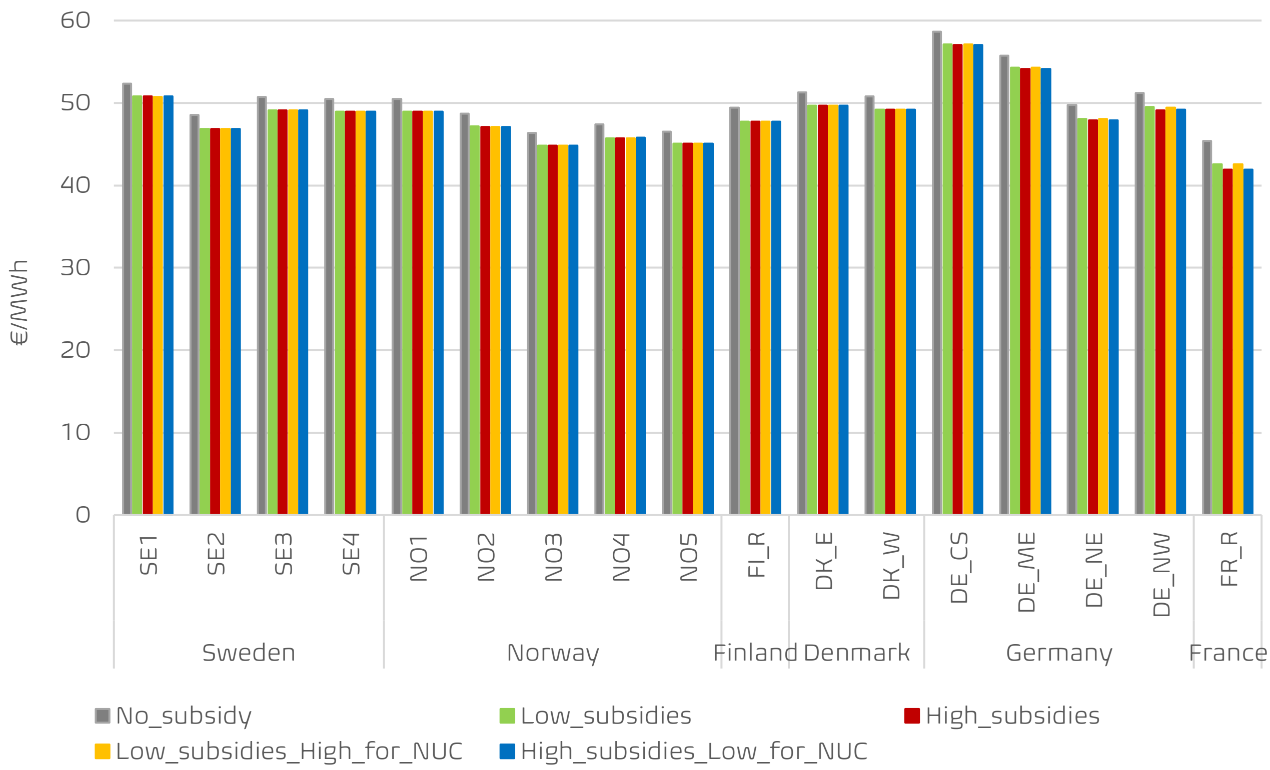


Figure 20. Average whole-sale power prices in 2040 in different bidding zones in Northern and Central Europe for different scenarios of future subsidy schemes.

The impact of the different subsidy schemes on capture prices in Sweden in 2040 for nuclear power and the variable RES technologies is illustrated on Figure 23.

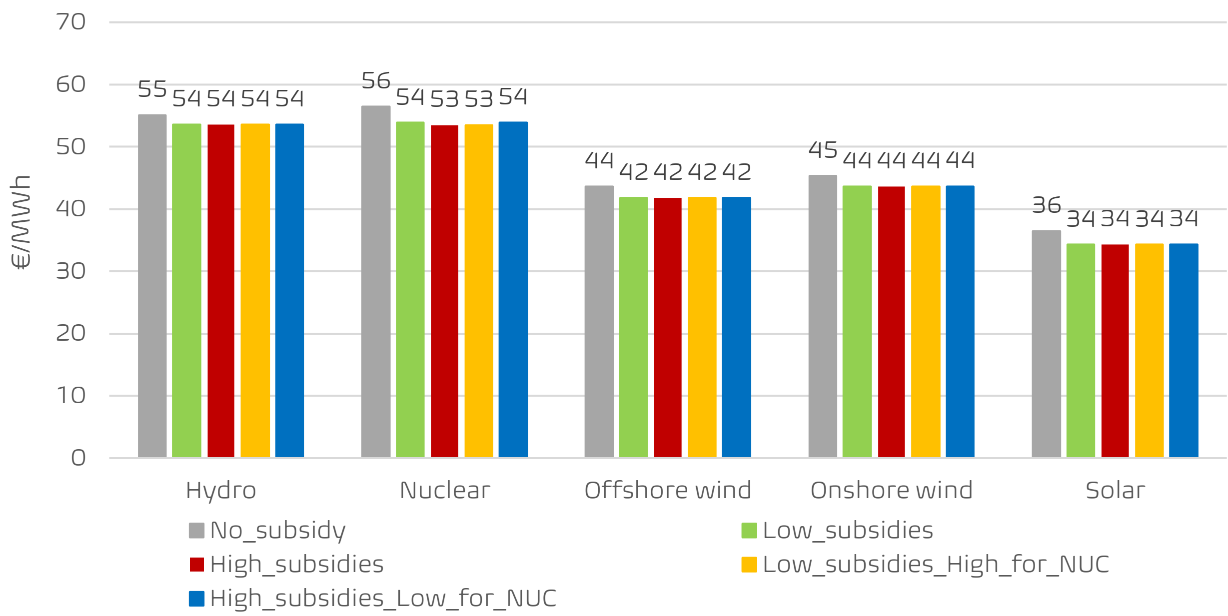


Figure 21. Average capture prices in Sweden in 2040 for nuclear power and different RES technologies for different scenarios of future subsidy schemes.

As shown in Figure 14, compared to the No_subsidy scenario, the different subsidy schemes lead to capture prices reductions in Sweden in 2040 of approx. 1-2 €/MWh for wind power and solar PV, approx. 2-3€/MWh for nuclear power, and approx. 1 €/MWh for hydro power. This corresponds to 3-6 % reduction in revenue from electricity sales[22].

The model results thus suggest that **the price distortion of the analysed subsidy schemes only lead to modest reduction in the revenue from electricity sales for nuclear power and variable RES technologies in Sweden**.

If the illustrated revenue loss due to the price distortions where to be compensated, it would imply an addition subsidy need of approx. €36-54 mill. per year for the 2.5 GW new nuclear in 2040.[23]

[22] 3 % reduction for hydro power, 4 % reduction for wind power, 5 % reduction for nuclear power, and 6 % reduction for solar PV.

[23] Estimated based on the capture price reduction of approx.. 2-3 €/MWh between the No_subsidy scenario and subsidy scenarios) and a power generation of around 18 TWh for this nuclear capacity in 2040 in the optimisation.

3. Discussion & conclusion

It is found that the Balmorel model version developed can replicate the magnitude of negative power prices, observed historically in the European energy system. The model has been used to analyse the potential impact of different subsidy schemes on day-ahead power prices, capture prices, and power generation in different countries. Effects on operation of the energy system have been examined, while potential effects on capacity investments are not investigated. Due to the project focus on distortions that can lead to negative prices, the scenarios only represent subsidies on non-fossil technologies with very low marginal operation costs: wind power, solar PV, hydro power, and nuclear power[24]. The key messages of the model results are summarized and shortly discussed below:

Key findings for the European power system

- The total number of negative power prices in the European countries covered, is more than doubled from 2025 to 2040. This reflects the increasing shares of wind power and solar PV in the European power mix.
- The subsidy schemes only marginally impact the dispatch of the power system. The reason is that the susidized technologies have low marginal operation costs and are thus generally dispatched among the first options in the merit-order; also without power generation subsidies.

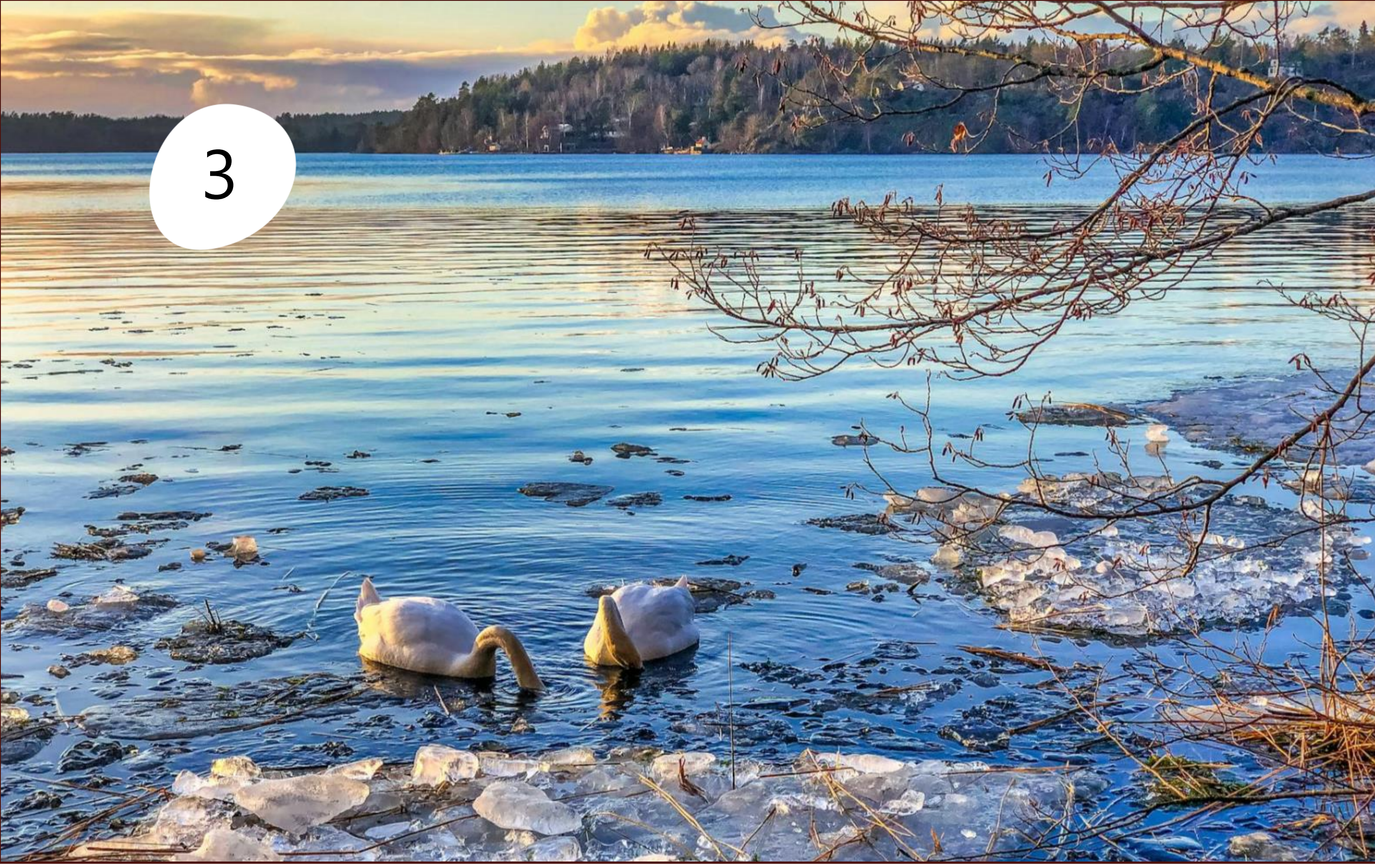
[24] Subsidies on biomass/bioenergy based technologies are thus not covered.

- Subsides on power generation to some extent distort power prices in all the modelled European countries, illustrated by changes in the power price duration curve. However, even in the high subsidy scenario, the power price formation is not fundamentally altered. As such, the defined high/low levels of subsidies on power generation have only modest impacts on average whole-sale prices towards 2040 in the modelled European countries (reductions of 2-3 € /MWh).

Considering the large share of wind, solar, hydro, and nuclear in the future European energy system (approx. 90 % in 2040), one could expect more substantial power price reductions in the high subsidies schemes analyzed. The main explanation for the limited price distortion is likely that a significant part of the future electricity demand is expected to be flexible, particularly electricity for power-to-X applications. To some extent, this counterbalances the effect of increasing shares of variable RES in the power mix. If the roll out of power-to-X technologies and infrastructure in Europe is delayed or lower than currently expected, the future energy system would be less flexible; implying potentially larger power price distortions from the subsidy schemes than indicated in this study.

Key findings for Sweden

- The subsidy schemes have only limited impact on the dispacth of the Swedish power system. For instance high subisdies on the new nuclear power unit in Sweden (2.5 GW assumed in 2040) leads to a production increase of approx. 9 % (corresponding to approx. 3 % in the total Swedish nuclear power generation). The subsidy schemes lead to modest increases (up to 0.1 TWh) in onshore wind power and solar PV based electricity generation in Sweden, which reflects reduced curtailment.
- The number of negative power prices in Sweden is reduced towards 2040 in SE1 and SE2, while they are increased in SE3 and SE4.
- The subsidy schemes result in limited occurrence of negative power prices in Sweden in 2040 compared to some Central/Southern European countries. This is likely due to the significant amounts of reservoir hydro power in Sweden and the interconnections with the Norwegian hydro power reservoirs, which contributes to power balancing.
- The high subsidy scheme does not distort power prices in 2040 further than the low subsidy scheme.
- The modelled subsidies only have modest impacts on the revenue from electricity sales for wind power, solar PV, nuclear power, and hydro power technologies in Sweden (capture prices reduced with approx. 1-2 € /MWh, corresponding to 3-6 % reductions). As such, the subsidy schemes only to a modest extent counterbalance the desired outcome of incentivising the subsidised technologies.
- Supporting the new nuclear power capacity (2.5 GW) in Sweden in 2040 with a conventional CfD has a negligible effect on power prices in Sweden.



4. Appendix

This Appendix provides the more detailed data and assumptions applied in the analysis.

4.1. Estimated capacities on different subsidy schemes

Table 5, Table 6, and Table 7 show the estimated capacities of solar PV and wind power on different subsidy schemes, for the countries where sufficient data is identified in central sources.

Table 6. Estimated existing solar PV capacities on different subsidy schemes (per 2020/2019).
The data is used for estimating how existing solar PV capacities are distributed percentagewise on different subsidy levels.

Solar (MW)	Feed-in tariff*	Feed-in premium*	PPA**
Austria	443	706	-
Belgium	-	-	50
Czech	-	-	-
Denmark	n/a	n/a	1,367
Estonia	81	129	-
Finland	n/a	n/a	24
France	4,281	6,824	2,177
Germany	20,712	33,009	2,730
Great Britain	4,242	6,761	1,493
Italy	6,789	10,821	735
Latvia	-	-	-
Lithuania	27	43	-
Luxembourg	61	96	-
The Netherlands	1,813	2,889	414
Norway	n/a	n/a	-
Poland	237	378	1,110
Portugal	114	182	-
Spain	-	-	6,876
Sweden	n/a	n/a	438
Switzerland	-	-	-

*Estimated based on 1) Type of subsidy schemes applied in the given country in 2020 (source: CEER (2023)[25] and 2) Average split for all countries of solar PV generation on different subsidy schemes (feed-in tariffs and feed-in premiums) in 2019 (source: EU Commission (2023)[26].
**Based on PPA's Wind Energy Europe (2024)[27].
n/a: no available data in the central sources identified. "-": Zero value according to the source.

[25] https://www.ceer.eu/wp-content/uploads/2024/04/RES_Status_Review_in_Europe_for_2020-2021.pdf

[26] https://economy-finance.ec.europa.eu/system/files/2023-06/dp187_en_energy%20markets.pdf

[27] https://windeurope.org/intelligence-platform/product/the-corporate-ppa-tool/#interactive-data

Table 7. Estimated existing onshore wind on different subsidy schemes (per 2020/2019).
The data is used for estimating how existing onshore wind capacities are distributed percentagewise on different subsidy levels.

Onshore wind (MW)	Feed-in tariff*	Feed-in premium*	PPA**
Austria	2,495	-	-
Belgium	-	-	855
Czech	-	-	-
Denmark	n/a	n/a	278
Estonia	320	-	-
Finland	n/a	n/a	2,094
France	16,580	-	407
Germany	54,414	-	3,457
Great Britain	13,668	-	2,221
Italy	8,746	-	431
Latvia	64	-	-
Lithuania	410	-	-
Luxembourg	129	-	-
The Netherlands	2,419	-	2,438
Norway	n/a	n/a	2,491
Poland	89	-	716
Portugal	5,718	-	-
Spain	-	-	2,645
Sweden	n/a	n/a	3,933
Switzerland	-	-	-

*Estimated based on 1) Type of subsidy schemes applied in the given country in 2020 (source: CEER (2023)[28] and 2) Average split for all countries of onshore wind generation on different subsidy schemes (feed-in tariffs and feed-in premiums) in 2019 (source: EU Commission (2023)[29].
**Based on PPA's Wind Energy Europe (2024)[30].
n/a: no available data in the central sources identified. "-": Zero value according to the source.

[28] https://www.ceer.eu/wp-content/uploads/2024/04/RES_Status_Review_in_Europe_for_2020-2021.pdf

[29] https://economy-finance.ec.europa.eu/system/files/2023-06/dp187_en_energy%20markets.pdf

[30] https://windeurope.org/intelligence-platform/product/the-corporate-ppa-tool/#interactive-data

Table 8. Estimated existing offshore wind on different subsidy schemes (per 2020/2019).
The data is used for estimating how existing offshore wind capacities are distributed percentagewise on different subsidy levels.

Offshore wind (MW)	Feed-in tariff*	Feed-in premium*	PPA**
Austria	-	-	-
Belgium	1,470	796	-
Czech	-	-	-
Denmark	n/a	n/a	-
Estonia	-	-	-
Finland	n/a	n/a	-
France	-	-	-
Germany	5,051	2,736	-
Great Britain	6,468	3,503	-
Italy	-	-	-
Latvia	-	-	-
Lithuania	-	-	-
Luxembourg	-	-	-
The Netherlands	1,355	734	-
Norway	n/a	n/a	-
Poland	-	-	-
Portugal	16	9	-
Spain	-	-	-
Sweden	n/a	n/a	-
Switzerland	-	-	-

*Estimated based on 1) Type of subsidy schemes applied in the given country in 2020 (source: CEER (2023)[31] and 2) Average split for all countries of offshore wind generation on different subsidy schemes (feed-in tariffs and feed-in premiums) in 2019 (source: EU Commission (2023)[32].
**Based on PPA's Wind Energy Europe (2024)[33].
n/a: no available data in the central sources identified. "-": Zero value according to the source.

[31] https://www.ceer.eu/wp-content/uploads/2024/04/RES_Status_Review_in_Europe_for_2020-2021.pdf

[32] https://economy-finance.ec.europa.eu/system/files/2023-06/dp187_en_energy%20markets.pdf

[33] https://windeurope.org/intelligence-platform/product/the-corporate-ppa-tool/#interactive-data

4.2. Estimated percentagewise distribution on different subsidy levels

Table 8, Table 9, and Table 10 show the estimated distribution of existing solar PV and wind power capacities based on different subsidy levels. For the countries with available data, the percentagewise distributions are estimated based on the capacity splits in Table 5, Table 6, and Table 7 (in a few cases after manual adjustment). For countries without available data, the percentagewise distributions are based on the distributions for other countries.

It is assumed that hydro reservoir power and run-of-river power generation units receive only low subsidy levels. For simplicity and to avoid heavy model runs, it is generally assumed that all hydro power units receive the low subsidy level (guarantees of origin, so in this case support from private stakeholders).

For nuclear power, 35 % of existing capacities are for all countries assumed to receive the medium subsidy level, and 65 % the low subsidy level.

Table 9. Assumed distribution of existing solar PV capacities on different subsidy levels.

Pct.	MaxSub	HSub	MSub	LSub
Austria	39%	31%	31%	0%
Belgium	30%	25%	25%	20%
Czech	30%	25%	25%	20%
Denmark	30%	25%	25%	20%
Estonia	39%	31%	31%	0%
Finland	30%	25%	25%	20%
France	35%	34%	30%	1%
Germany	37%	29%	29%	5%
Great Britain	34%	27%	27%	12%
Italy	37%	29%	29%	4%
Latvia	30%	25%	25%	20%
Lithuania	39%	31%	31%	0%
Luxembourg	39%	31%	31%	0%
The Netherlands	35%	28%	28%	8%
Norway	30%	25%	25%	20%
Poland	14%	11%	11%	64%
Portugal	39%	31%	31%	0%
Spain	30%	10%	10%	50%
Sweden	30%	25%	25%	20%
Switzerland	30%	25%	25%	20%

Table 10. Assumed distribution of existing onshore wind capacities on different subsidy levels.

Pct.	MaxSub	HSub	MSub	LSub
Austria	100%	0%	0%	0%
Belgium	75%	0%	20%	5%
Czech	75%	0%	20%	5%
Denmark	0%	0%	25%	75%
Estonia	100%	0%	0%	0%
Finland	75%	0%	20%	5%
France	98%	0%	0%	2%
Germany	94%	0%	0%	6%
Great Britain	86%	0%	0%	14%
Italy	95%	0%	0%	5%
Latvia	100%	0%	0%	0%
Lithuania	100%	0%	0%	0%
Luxembourg	100%	0%	0%	0%
The Netherlands	50%	0%	0%	50%
Norway	75%	0%	20%	5%
Poland	11%	0%	0%	89%
Portugal	100%	0%	0%	0%
Spain	75%	0%	20%	5%
Sweden	0%	0%	5%	95%
Switzerland	75%	0%	20%	5%

Table 11. Assumed distribution of existing offshore wind capacities on different subsidy levels.

Pct.	MaxSub	HSub	MSub	LSub
Austria	65%	18%	18%	0%
Belgium	65%	18%	18%	0%
Czech	65%	18%	18%	0%
Denmark	45%	18%	18%	20%
Estonia	65%	18%	18%	0%
Finland	65%	18%	18%	0%
France	65%	18%	18%	0%
Germany	65%	18%	18%	0%
Great Britain	65%	18%	18%	0%
Italy	65%	18%	18%	0%
Latvia	65%	18%	18%	0%
Lithuania	65%	18%	18%	0%
Luxembourg	65%	18%	18%	0%
The Netherlands	65%	18%	18%	0%
Norway	65%	18%	18%	0%
Poland	65%	18%	18%	0%
Portugal	65%	18%	18%	0%
Spain	65%	18%	18%	0%
Sweden	65%	18%	18%	0%
Switzerland	65%	18%	18%	0%

4.3. Power price duration curves for SE2 and SE4

Power price duration curves in 2040 for the Swedish bidding zones, SE2 and SE4, for the modelled scenarios with different subsidy schemes is illustrated in Figure 22 and Figure 23.

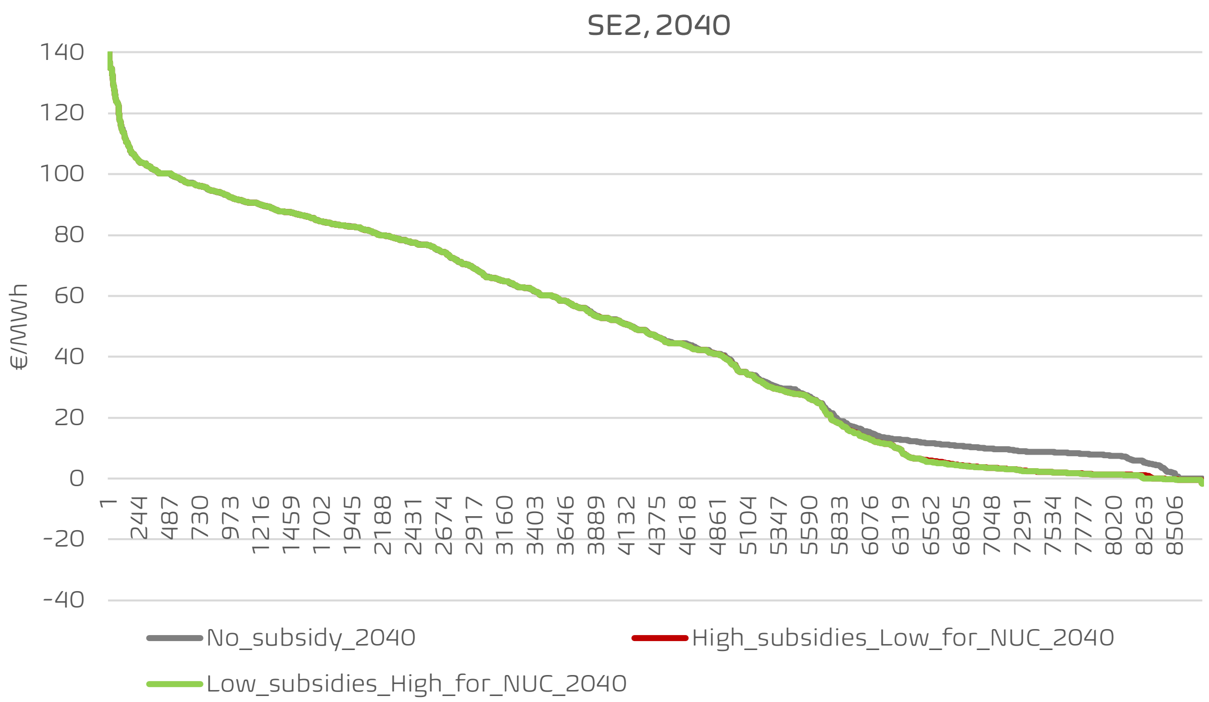


Figure 22. Power price duration curve for SE2 in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

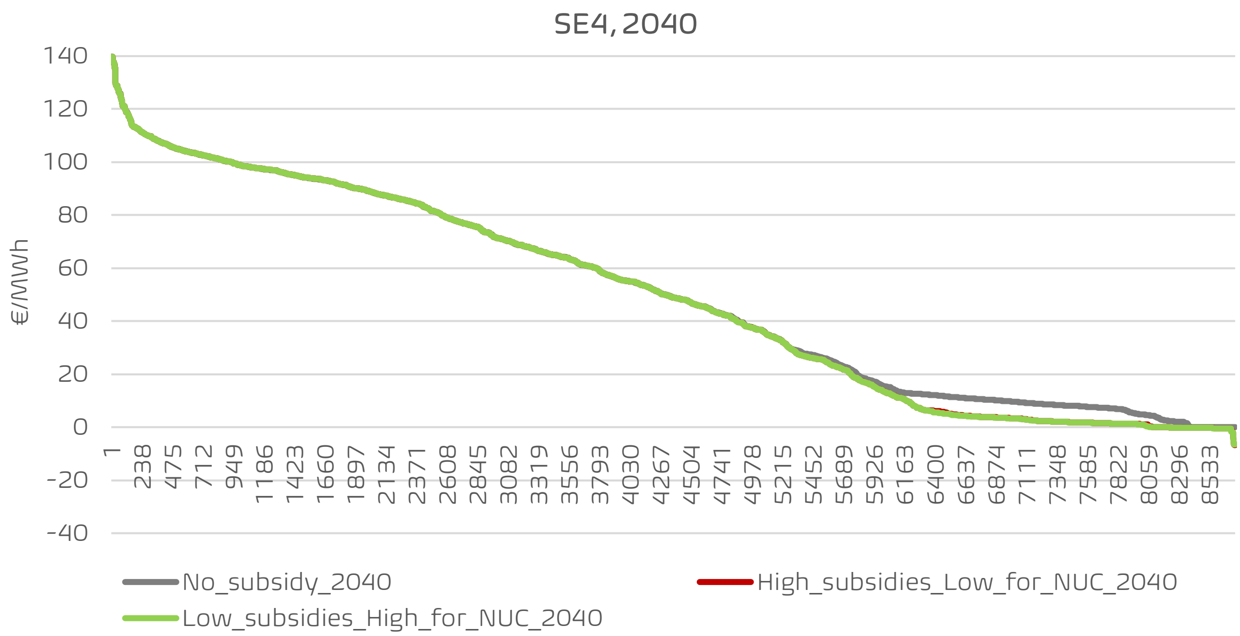


Figure 23. Power price duration curve for SE4 in 2040 for the scenarios No_subsidy, High_subsidies, and Low_subsidies.

POWER PRICE DISTORTIONS OF SUBSIDY SCHEMES IN NORTHEN EUROPE

This report analyses how different electricity generation support schemes may affect future electricity prices and power generation in Northern Europe, with a particular focus on Sweden. The analysis has been conducted within the framework of the Nepp research project (North European Energy Perspectives) as input to the 2035 projects within Nepp.

The results show that support schemes for fossil-free electricity generation have only a limited impact on power system dispatch and on average electricity prices but may lead to certain shifts between generation technologies as well as moderate changes in so-called capture prices. The study thus contributes new knowledge on how support schemes can influence the functioning of the electricity market in a future Nordic and European energy system.