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Flexible use of Electricity in Heat-only District Heating Plants

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ABSTRACT

European energy systems are in a period of significant transition, with the increasing shares of variable renewable energy (VRE) and less flexible fossil-based generation units as predominant factors. The supply-side changes are expected to cause large short-term electricity price volatility. More frequent periods of low electricity prices may mean that electric use in flexible heating systems will become more profitable, and such flexible heating systems may, in turn, improve the integration of increasing shares of VRE.

The objective of this study is to analyze the likely future of Nordic electricity price levels and variations and how the expected prices might affect the use of electricity and thermal storage in heat-only district heating plants. We apply the North European energy market model Balmorel to provide scenarios for future hourly electricity prices in years with normal, high, and low inflow levels to the hydro power system. The simulation tool energy PRO is subsequently applied to quantify how these electricity price scenarios affect the hourly use of thermal storage and individual boilers in heat-only district heating plants located in Norway. The two studied example plants use wood chips or heat pump as base load representing common technologies for district heating in Norway.

The Balmorel results show that annual differences in inflow is still a decisive factor for Norwegian and Nordic electricity prices in year 2030 and that short-term (daily) price variability is expected to increase. In the plant-level simulations, we find that tank storage, which is currently installed in only a few district heating plants in Norway, is a profitable flexibility option that will significantly reduce the use of fossil peak load in both biomass and heat-pump-based systems. Installation of an electric boiler in addition to tank storage is profitable in the heat pump system due to the limited capacity of the heat pump. Electricity will hence, to a large extent, replace gas when heat demand exceeds the capacity of the heat pump. For the bio-based plant, we find that an electric boiler in addition to tank storage is not profitable in the normal electricity price scenario. The electric boiler investments are only profitable when electricity prices are as low as in the high inflow scenario. In that case the electric boiler will provide 17% of the heat supply in the example plant. Fuel prices for peak load and electricity grid tariffs are found to be decisive factors for the electricity use – and therefore flexibility options – provided by heat-only district heating plants.

Keywords:

Flexible operation;
Electricity prices;
Renewable energy integration;
Energy storages;

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1. Introduction

Climate change mitigation, increasing energy demand, and uncertainty related to costs of future fossil energy supply are major driving forces for increasing shares of renewable energy generation. The share of energy from renewable sources in EU-28 energy consumption was 16% in 2014 [1]. It is well known that maintaining the momentary balance between supply and demand in energy systems with large shares of variable renewable

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energy (VRE) is a major technical and economic challenge for the future of energy systems in most countries (e.g., [2], [3], [4]). A flexible energy system will be more capable of handling the variable supply of VRE and will reduce the challenges related to balancing supply and demand. [5] found that the flexibility in Denmark's normal electricity demand was too small to assist the integration of VRE. [6] found that the demand-side flexibility improved the integration of VRE, but needed policy stimulation and had limited reduction in GHG emissions.

District heating systems can provide flexible electricity consumption and efficient energy storage, both of which are desirable in power markets increasingly dominated by VRE supply. In contrast to consumer-orientated flexible demand-side technologies, proper transfer of price signals to the electricity consumer is likely to be easier in district heating systems. In a review of nearly 400 studies of flexibility options, [3] conclude that increased interaction between the electric system and the heating sector (power-to-thermal, P2T) is a promising option that does not require large investments or technological development. Flexible heating systems as district heating will play an important role in future renewable energy systems [7], [8].

There are three main driving forces that will likely lead to increased use of electricity in district heating systems in future energy systems: 1) increasing VRE shares – causing more frequent periods with excess power supply and thus low electricity prices, 2) the need to reduce fossil fuels usage, and 3) increased competition for biomass resources from the transport sector and green chemicals. From the heating business viewpoint, increased use of electricity when electricity prices are low represents an opportunity for reduced costs and reduced carbon footprint. Heat is relatively easy to store, and increased use of thermal storage capacity, in combination with electric boilers, may reduce the need for peak-load capacity based on fossil fuel. Furthermore, by electricity/heat market integration, excess VRE supply may be stored as heat, and later provide heat in periods with low VRE supply and high heat demand. In total, such flexible use of fuels can reduce the overall costs of the energy system through reduced balancing costs, reduced price volatility, and reduced emissions, and can give a more cost-effective integration of VRE ([3], [9]).

Increased population, enhanced building services and comfort levels, and increased time spent inside buildings have raised buildings' energy consumption levels up to the levels of transport and industry [10]. The European Commission [11] states that buildings are responsible for 40% of energy consumption and 36% of CO_2 emissions in the European Union. At the same time, this sector is also regarded among the most challenging to decarbonize and the large volumes of fossil fuel energy directly delivered to the buildings create local safety and emission issues [12]. The share of renewable energy in heating and cooling is slowly increasing in the European Union, but it is still low compared to renewable shares in electricity generation. In 2014, renewable energy accounted for 17.7% of total energy use for heating and cooling in the EU-28, compared to 27.5% in electricity generation [1].

In Norway, district heating is growing but is still low compared to direct space heating. District heating accounted for about 8% of the heat demand in the residential and service sectors in 2015 [37]; 62% was delivered to the service sector and 21% to households. Refuse incineration plants produced 49% of the delivered heat, wood and biofuel boilers 21%, electric boilers 12%, heat pumps 10%, and oil and gas boilers 5%. Generally, an electric boiler is more suited for flexibility purposes than heat pumps, since the heat pumps have the economic characteristics of a base-load technology – high investment costs with low operational costs [3]. So-called "un-prioritized" electric boilers in flexible district heating systems that can be discharged immediately or with two hours' notice usually have a special and low grid tariff. Interest in the use of electric boilers in Norway is growing due to periodically low electricity prices, but the share of district heat delivered by electric boilers or heat pump is currently not increasing [13].

A few previous studies have addressed benefits and challenges related to electricity use in district heating systems. [14] and [2] studied the benefits of a flexible interaction between heat and power markets. [15] studied the impact of reduced heat demand and electricity price variations for district heating systems in Sweden, finding that low seasonal variations in electricity price levels, in combination with relatively low winter prices, promote the use of electric heat pumps. High winter prices, on the other hand, promote co-generation of heat and electricity in CHP plants. [7] analyzed the role of district heating in Denmark's future energy system and found that in a 100% RES system, electricity-consuming options (electric heating and heat pumps) increase, while electricity-producing options (CHP) decrease. According to [16], heat pumps can contribute significantly to facilitating larger wind power investments and reducing system costs, fuel consumption, and CO_2 emissions, even without flexible operation. [17] found that an electric boiler provides consistent improvements in the intermittency-friendliness of distributed cogeneration but that heat pump concepts are more cost-effective than electric boilers. Furthermore, heat pumps in combination with intermediate thermal storages represented a superior opportunity to combine an intermittency-friendly pattern of operation with the efficient use of electricity in heating and cooling production. The plant-level analyses referred to above generally assume persistence of the current price structure of electricity, or are based on rough assumptions regarding the future energy system's price structure.

Thermal storage in accumulator tanks exist in only a few plants in Norway but is attracting increased interest among district heating companies. Ambitions to reduce the use of fossil peak load and periods with low electricity prices seem to be the cause for the interest. Storage options in a system perspective is analyzed by [18]. Thermal storage related to CHP plants is studied by [19], [20], [21], [22], [16,23]. Thermal storage is analyzed in relation to solar heating and seasonal storage in several papers (see, e.g., [24]) as well as in relation to combined solar and biomass district heating systems [25].

In our study, the objective is to analyze how short-term storage affects electricity use and profitability in a flexibility context. The paper highlights how the likely development of hourly electricity prices will affect the opportunities for increased use of flexible electric boilers in the district heating sector, as well as the profitability and use of storage. The analyses are done by applying a two-step procedure: In the first step, we develop scenarios for future electricity price levels and for short-term electricity price variation, based on different assumptions for the future power system. We use the Nordic power market and the Norwegian heating system as a case, and apply a detailed North European energy market model – Balmorel – to provide scenarios for future electricity prices at an hourly resolution. In the second step, we apply these model results to analyze how different electricity price scenarios affect the economic feasibility of electric boilers in heat-only district heating plants. The analyses are made for two small-to-medium scale district heating systems (23 MW) based on biomass and heat pumps, respectively – these technologies are common in heat plants in Norway. We have used the plant-level operational model energyPRO to analyze both the use of individual boilers on an hourly basis and the profitability of installing electric boilers in this plant. As the use of thermal storage will influence the use of electric boilers, we also analyze the impacts of thermal storage in the system. Finally, we analyze the impacts of the level of electricity grid tariffs for electricity consumption. The novelty of this study is the linkage between an energy market model that covers the relevant power market developments on an hourly basis and a plant-level operational model. This linkage makes it possible to analyze how changes in the power market and possible change in inflow will affect daily operation and future fuel use on an hourly basis. Figure 1 shows the linkage between assumptions, models, and outputs in the study.

Chapter 2 gives a description of the applied models and assumptions regarding the modeling of future electricity prices and the costs and operation of the analyzed heating system. Chapter 3 shows future electricity prices under different weather scenarios. Chapter 4 shows first the use and profitability of tank storage and then how installation of electric boilers influence boiler use and profitability in the analyzed district heating systems under different electricity price scenarios. Results and implications are discussed in chapter 5.

2. Methods, data and assumptions

2.1. Balmorel

The power and heat market model applied for the analysis is based on the Balmorel model structure, which is a convex and linear partial equilibrium model simulating the generation, transmission, and consumption of electricity and heat under the assumption of competitive markets [26]. The model version applied is formulated as a linear optimization problem in GAMS. The model optimizes the operation of the system by minimizing total costs in the energy system over a given year, covering operation and maintenance costs, as well as fuel and CO_2 quota costs. The optimization is performed subject to a number of constraints including satisfaction of demands for electricity and heat in each period and technical restrictions on units in the system. The optimization is performed with a yearly time horizon where the year is divided into 52 weeks of 168 hours each. The applied model version is updated with 2012 data, and covers the Nordic countries, Germany, the Netherlands, and the United Kingdom. The Nordic countries are modeled as 22 regions, providing a detailed representation of their respective electricity systems. The modeling of district

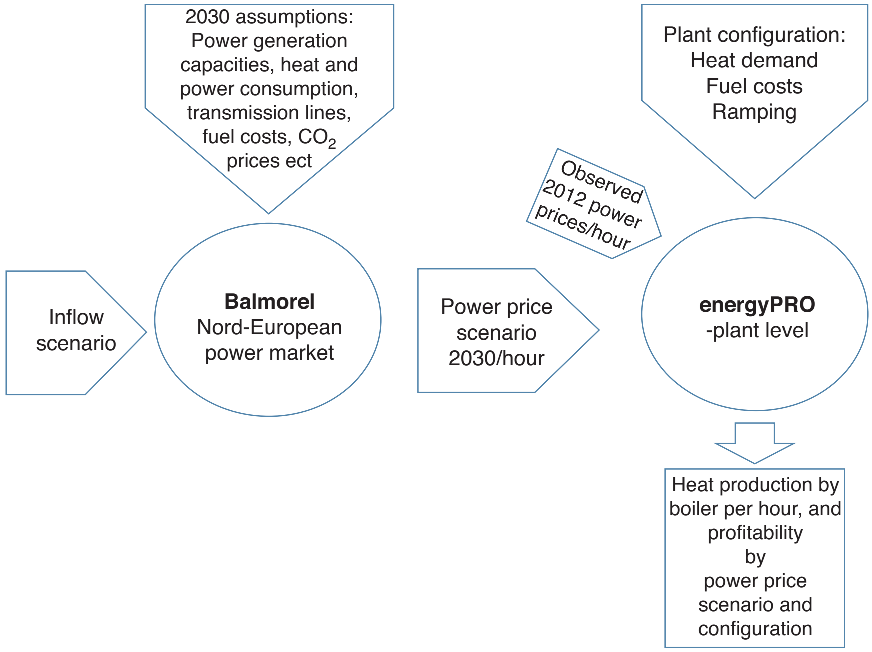


Figure 1: Flow diagram of applied modeling in the study

heating requires finer spatial resolution and is represented by 14 areas in Norway, 13 areas in Sweden, 8 areas in Denmark, and 7 areas in Finland. Most exogenous parameters like demand, capacities of the different generation technologies, transmission capacity, and availability of VRE are specified individually for each region. The model calculates the electricity production per technology, time unit, and region, minimizing total system costs for a given electricity and heat demand. A more thorough description of the model is given in Appendix 1.

2.2. energyPRO

energyPRO [27] is a modeling software package used for the combined techno-economic design, analysis, and optimization of plants. Co-generation and tri-generation, as well as other types of complex energy projects involving energy storage, can be modeled in energyPRO. In an energyPRO market optimization, the market prices of an entire year are divided into market price intervals, with each interval containing a number of hours. energyPRO allows the daily optimization of the operation to be made against fixed tariffs for electricity or against hourly spot market prices. The optimization takes into account the limited sizes of thermal and fuel storages. In the operation strategy, a matrix shows priority numbers that determine in which order production units shall produce; the order is determined by defined prices for each interval. The mathematical solver in energyPRO will test all available possibilities for a production unit to produce at certain hours and within a certain price interval, taking into account all restrictions in demand and energy storage. The optimization procedures of energyPRO are further described in [28] and [29].

energyPRO has previously been used in different scientific studies of thermal power systems. [30] analyzed the financial feasibility of integrating large-scale heat pumps with existing combined heat and power plants. [20] used energyPRO to analyze the optimal size of a CHP plant with thermal storage under German spot market conditions. [28] studied use of compressed air energy storage (CAES) for load leveling of electricity supply. [31] used energyPRO to analyze the integration of large-scale energy system into the domestic district heating system by calculating the effects of various local fuels. [32] applied energyPRO for an all-inclusive 100% renewable energy scenario developed for the Danish city Aalborg. [33] used energyPRO to evaluate the influence of an accumulator tank in a CHP plant by using real input data on the operation of a district heating system, whereas [34] applied energyPRO in a study of how domestic hot water should be supplied in a low-temperature district heating system.

2.3. Power market assumptions

In this study, the assumed installed net capacities for the different production technologies were determined exogenously based on the assumed installed net capacities used by [35], as specified in Table 1.

Based on studies by [36–37] and [38], we assume 2030 prices of hard coal, natural gas, and fuel oil at 9.3 €/MWh, 27.3 €/MWh, and 59 €/MWh, respectively. Prices for biomass and straw range from 20.1 €/MWh to 30.2 €/MWh, depending on quality. The CO_2 price is set to expected 2030 levels of 35 €/t.

The assumed annual consumption of electricity and heat is in Table 2. Electricity consumption is given as net consumption (gross consumption minus network losses minus energy used for pumped hydro), while consumption for district heat is given as gross consumption. The yearly growth rates correspond to the growth rates in the EU Commission's *Roadmap to 2050* [35]. For the electricity consumption, we apply the observed hourly consumption profile of 2012 to distribute the annual consumption over the modeled 8,760 hours.

Towards 2030, the electrical grid will be strengthened by both national and international grid projects. The study assumes that the currently planned interconnections are realized, and a list of new interconnectors can be found in Appendix 2.

The annual inflow level to the hydro reservoirs can vary approximately 30% from the normal level, and the precipitation levels is thus a major price driver in the Norwegian power market. In order to illustrate the electricity price impacts of variability in annual perception, we have forecasted the electricity prices in Norway under "normal," "wet," and "dry" hydrological conditions, resulting in the corresponding Nordic hydropower production assumptions shown in Table 3. The prices for price region NO_3 (Central Norway) were used because the modeled plant is assumed to be located there. The variation in solar and wind production is captured in the hourly resolution of the model, but is assumed not to vary between years. 2012 is applied as the base year for the hourly profile of wind and solar power. The hourly profile of VRE is based on observed regional production data in the base year.

2.4. Techno-economic assumptions for heat plants

2.4.1. Plant specification

Annual heat delivered to customers is assumed to be 63.7 GWh/229TJ in all years and annual heat loss is assumed to be 15%. The profitability of an (supplementary) electric boiler with 5 MW capacity is analyzed in a heat-only district heating plant using wood biomass as base load. Table 4 shows the plant configuration analyzed in this study.

2.4.2. Heat prices and fuel costs

The consumer price for district heating typically consists of an initial connection fee, an annual fee, and the price for heat consumption, which can be divided into load

Table 2: Assumed annual consumption of district heat and electricity for the year 2030 (TWh)

	Consumption of district heat	Consumption of electricity
Norway	8	117
Sweden	50	138
Denmark	34	31
Finland	36	83
Germany	–	549
Netherlands	–	120
UK	–	339

Table 3: Assumed annual hydropower production in the Nordic countries (TWh)

Observed 2012	Normal 2030	Wet 2030	Dry 2030
236.4	215.4	249.6	175.0

Table 1: Assumed installed net capacity per fuel in the 2030 scenario (GW)[1]

	Nuclear	Natural Gas	Hard Coal	Lignite	Oil-fired	CHP (and biomass)	Wind	Solar	Hydro
Norway	–	–	–	–	–	–	4.1	–	36.1
Sweden	6.7	–	–	–	1.2	5.2	9.4	–	16.9
Denmark	–	–	–	–	0.6	4.2	6.7	1.4	–
Finland	4.5	0.0	–	–	1.1	7.3	3.9	–	3.4
Germany	–	20.0	18.0	14.6	1.0	31.2	67.1	68.0	11.0
Netherlands	0.6	8.4	5.0	–	0.7	14.1	12.7	1.5	0.0
UK	8.4	35.0	6.1	–	1.7	11.4	51.3	23.3	4.5

1) Based on [35]

and energy costs. In Norway, for customers that have to connect to a district heating system (new buildings within the concession area of a district heating system), the heat price is regulated to be within the cost of electric heating within that area (The Energy Act §5-5). District heating prices in Norway are usually set according to the same regulations for all customers. Historic district heating prices in Norway are published by Statistics Norway [13].

In the analysis, the hourly price of district heating is assumed to be 95% of the hourly price of electricity (including grid cost and taxes as specified in Table 5, except for VAT); thus, the revenue will vary in the scenarios due to differences in electricity prices, even if the amount of heat delivered is the same.

2.4.3. Fuel costs

Table 6 shows the assumed fuel costs applied in the scenarios. The electricity grid tariff reflects the relatively low tariffs for flexible electric boiler applied by most district grid operators in Norway. Note also the low electricity tax for district heating producers compared to common electricity consumers.

2.4.4 Investment costs

The applied investment cost for an electric boiler with 5 MW capacity is shown in Table 7.

2.4.5 Thermal storage

The storage enables district heating plants to store heat from periods of low heat demand and to use it during periods with higher heat demand, thus reducing the use of peak load. The plant can also take advantage of low fuel cost by producing heat for storage for later heat deliveries when fuel costs are higher or heat demand is below that necessary for efficient use of a bio boiler.

We have assumed a heat accumulator for short-time storage of water-based energy (1–3 days), with a 10% heat loss in the thermal storage, a 40K temperature difference between the incoming and outgoing water, and a temperature below 100˚C; hence, the heat accumulator tank can be designed as an atmospheric pressure tank. The size of the storage was varied from 500 m^3 to 5000 m^3. Based on comparison of reduced fuel costs in the base year 2012 and annual capital costs with 12% interest rate and 15 years' depreciation time, a storage of 2000 m^3 was found to be optimal, as increased storage size gave very limited increase in use and therefore lower profitability. The cost for the investment in thermal storage is in line with the results from a spring 2015 survey among Norwegian district heating companies regarding plans and cost for thermal storage. The investment costs for a 2000 m^3 thermal storage in Norway is specified in Table 8.

Table 4: Plant specifications

Factor	Biomass plant	Heat pump plant
Biomass boiler 1 minimum-maximum load	2–10 MW	n.a.
Biomass boiler 2 minimum-maximum load	1–5 MW	n.a.
Biomass boilers' efficiency	85%	n.a.
Gas boiler 1 minimum-maximum load	0–10 MW	0–10 MW
Gas boiler 2 minimum-maximum load	0–10 MW	0–10 MW
Gas boilers' efficiency	92%	92%
Heat pump minimum-maximum load	n.a.	1–10 MW
Heat pump COP[1]	n.a.	2.85
Electric boiler minimum-maximum load	0–5 MW	0–5 MW

[1)] Coefficient of Performance

Table 5: Prices of electricity for heat, excluding VAT

Factor	Rate	Comment
Grid	Households: 20.8 €/MWH Service: 19.9 €/MWH	TSO TrønderEnergiNett 2012
Electricity tax	13.6 €/MWH	Households and services 2012

Table 6: Fuel costs, heat production in district heating plant

Factor	Rate	Comment
Electricity prices	By scenario	Based on results from Balmorel
Electricity grid tariff	6.0 € /MWh for flexible electric boilers	Grid tariffs for use of electricity in district heating is assumed to be "energy-only" payment
Electricity tax	0.5 € /MWh	District heating producers pay a low electricity tax on all electricity used for heat production and supply.
Wood chips	20.4 € /MWh	Delivered plant
LPG (liquefied petroleum gas)	0.89 € /kg + 0.12 € CO_2 /kg in tax	Delivered plant

Table 7: Investment costs for electric boiler. Based on [39]

Technology	Capacity	Investment costs (mill. €)	Duration	Annual capital costs (1000 €)
Electric boiler	5 MW	0.71	20 years	57

2.4.6. Operation strategy

The overall operation strategies in the simulations are 1) fulfillment of the customers' heat requirements and 2) minimization of operational costs. When thermal storage is installed, storage is allowed for all units except for the peak-load boilers. All units are allowed to operate at partial load.

2.4.7. Structure of heat demand

Operation of a district heating plant depends on the structure of the heat demand. We have assumed that 80% of the heat deliveries are in the service sector and 20% are in the household sector (multi-dwellings). The heat demand is specified based on the hourly heat consumption of district heating customers in Trondheim in 2012. In 2015, 20.8% of the district heating in Norway was delivered to households, 61.6% to the service sector and 17.5% to industrial consumers [13]. Figure 2 shows the structure of heat demand in 2012.

3. Change in future level and structure of power and heat prices

Figure 3 shows the observed 2012 electricity prices and modeled prices for normal, wet, and dry inflow to the hydropower system specified in Table 3. The observed average prices and standard deviations are shown in Table 9. 2012 was a relatively wet and mild year, with relatively high price variability over the year. The daily variability is expected to increase and the modelled prices have a higher average daily standard deviation in the normal and dry inflow scenario compared to 2012.

4. Use of storage and electric boilers

4.1. Use of storage

Revenues and heat supply of boilers in a system without and with tank storage are shown in Table 10. In the bio-based system, storage increases EBITDA (earnings before interest, taxes, depreciation and amortization) by 14% with 2012 district heating prices, and the LPG boiler would produce only 0.7% of the heat. The heat supply of the individual boilers in January is shown in Figure 4. In the bio-based system the storage supplies heat in both peak-load and low-load periods, thereby enabling better utilization of the bio boiler.

In the heat pump system, storage increases EBITDA only by about 5% because the heat pump has a relatively low capacity to produce heat for storage and the storage for peak load must therefore be supplied by the LPG boiler.

Table 8: Investment costs for thermal storage. Based on [39]

Technology	Capacity	Investment costs (mill. €)	Duration	Annual capital costs (1000 €)
Thermal storage	2000 m^3	0.96	20 years	77

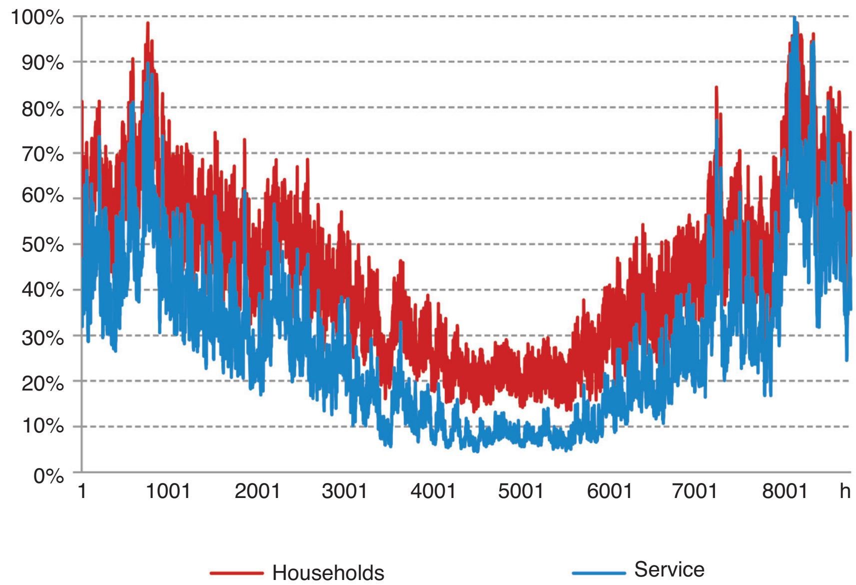


Figure 2: Structure of heat demand for the service sector (*Service*) and household sector (*Households*). Hourly share of maximal hourly consumption per sector. Based on data from Statkraft SF Trondheim 2012

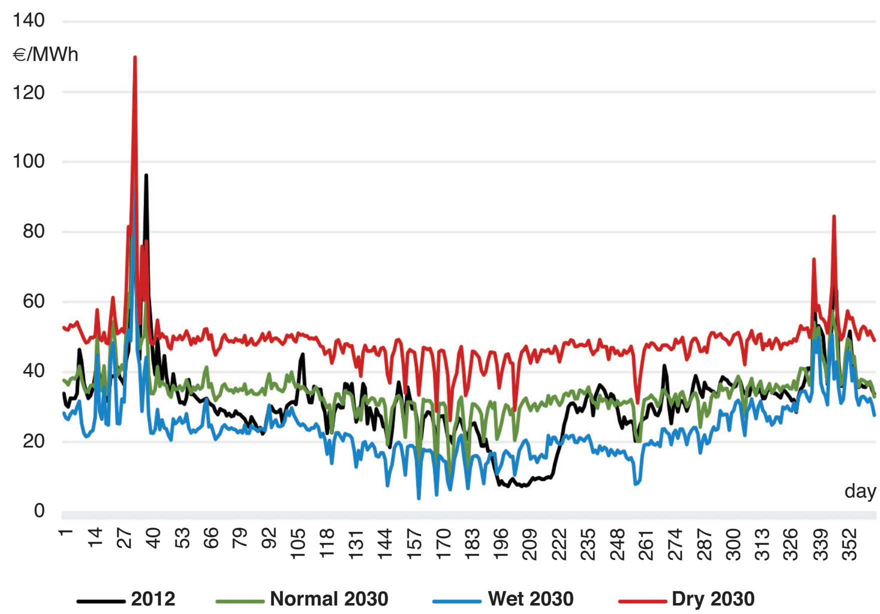


Figure 3: Average daily electricity prices in 2012 (observed) and modeled for 2030 under different precipitation scenarios. All prices are in 2012 real prices

Table 9: Observed 2012 and modeled 2030 electricity prices. €/MWh

Scenario	Average price	Average standard deviation over the day	Average standard deviation over the year
2012 Observed	31.5	4.24	13.87
2030 Normal	34.4	4.30	11.27
2030 Wet	23.9	3.77	11.22
2030 Dry	48.6	4.24	11.95

4.1. Use of electric boilers in the bio-based system

As shown above, the installation of tank storage can reduce the use of fossil fuel peak load from about 5% to almost zero in normal to wet years, relative to 2012. If an electric boiler as defined in Table 4 is installed, the electric boiler will deliver 2.9% of the heat in a 2030 normal-price scenario in a system with storage. If tank storage is installed, investment in electric boilers is not profitable in bio-based systems with the electricity price scenarios found in this study. This is because the combination of biomass boilers and tank storage generally provides heat from biomass with lower costs than from electricity. The electric boiler is used significantly in the bio-based system with tank storage only when the electricity prices are as low as in the wet year, when use of an electric boiler increases to 16.7% of heat deliveries and EBITDA increases by 3.7% (Table 11). Figure 5 shows the use of individual boiler in the bio-based system with tank storage in years with wet and dry hydrological conditions, respectively.

Investments in electric boilers are profitable the bio-based system with no storage except in dry years. If the normal electricity prices will tend to change towards the wet-2030 scenario, the profitability of an electric boiler

Table 10: Profitability and use of boilers in example plants with thermal storage

Configuration	Biobased: No storage	Bio-based with storage	Heat pump, no storage	Heat pump, with storage
Gross income (1000 €)	3,670	3,670	3,670	3,670
EBITDA (1000 €)[1]	1,150	1,320 (+14%)	2,000	2,100 (+5%)
Heat supply bio boilers	94.7%	99.3%	–	–
Heat supply heat pump	–	–	89.4%	91.1%
Heat supply LPG boiler	5.3%	0.7%	10.6%	8.9%

[1]) EBITDA in 2012. % increase compared to configuration without tank storage

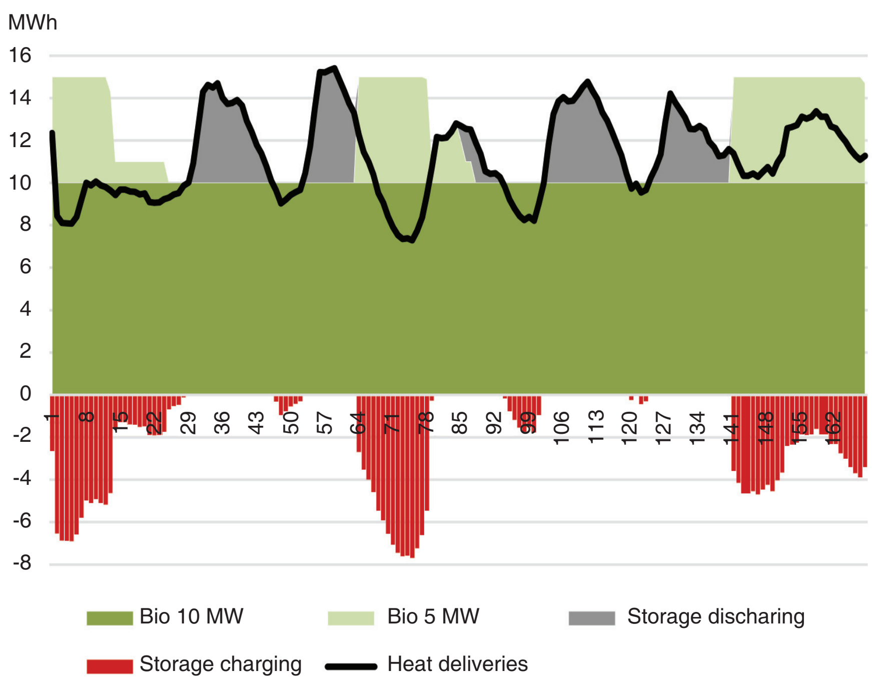


Figure 4: Heat supply by boiler and heat content in tank storage in the bio-based system in January, the 2030 normal electricity price scenario

will increase. The average 2015 electricity price (NO3) was close to the forecasted 2030 wet price as shown in Section 3.1. In all scenarios the use of LPG is reduced when an electric boiler is installed; hence, increased gas prices will increase the profitability of an electric boiler, whereas lower gas prices reduce profitability.

4.2. Use of electric boiler in the heat pump system

In the heat pump system, the combination of storage and electric boiler gives highest profitably in all price scenarios. Table 12 shows the revenues and use of boilers under different electricity price scenarios. Installation of electric boiler reduces the use of gas boiler from 8–10% to about 1% in the example plant, which gives more flexibility and higher profit. Figure 6 illustrates that an electric boiler will replace the use of the gas boilers.

4.3. Impacts of lower electricity grid tariffs for electric boilers

The cost of electricity for a heat producer can generally be separated into three parts: energy cost of electricity, grid cost, and taxes as specified in Table 6. Energy cost of electricity (the electricity price) is the largest part and is usually charged based on the hourly wholesale price of electricity. Grid cost is the second largest part and, according to [40], it constitutes between 20 and 50% of total electricity costs in European countries. We have analyzed the effect of the grid tariff on the use of the electric boiler in the bio

Table 11: Profitability and use of boilers under different electricity price scenarios in the bio-based system with storage

Scenario	Normal 2030, no electric boiler	Normal 2030 with electric boiler	Wet 2030, no electric boiler	Wet 2030 with electric boiler	Dry 2030, no electric boiler	Dry 2030 with electric boiler
Gross income (1000 €)	3,990	3,990	3,460	3,460	4,740	4,740
EBITDA (1000€)*	1,640	1,670	1,110	1,150	2,390	2,400
Heat supply bio boilers	99.3%	89.8%	99.3%	83.3%	99.3%	98.6%
Heat supply electric boiler	–	2.9%	–	16.7%	–	1.4%
Heat supply gas boilers	0.7%	0%	0.7%	0%	0.7%	0%

*EBITDA (1000€) and the use of boilers will be the same in all configurations without the electric boiler. % increase compared to configuration without electric boiler

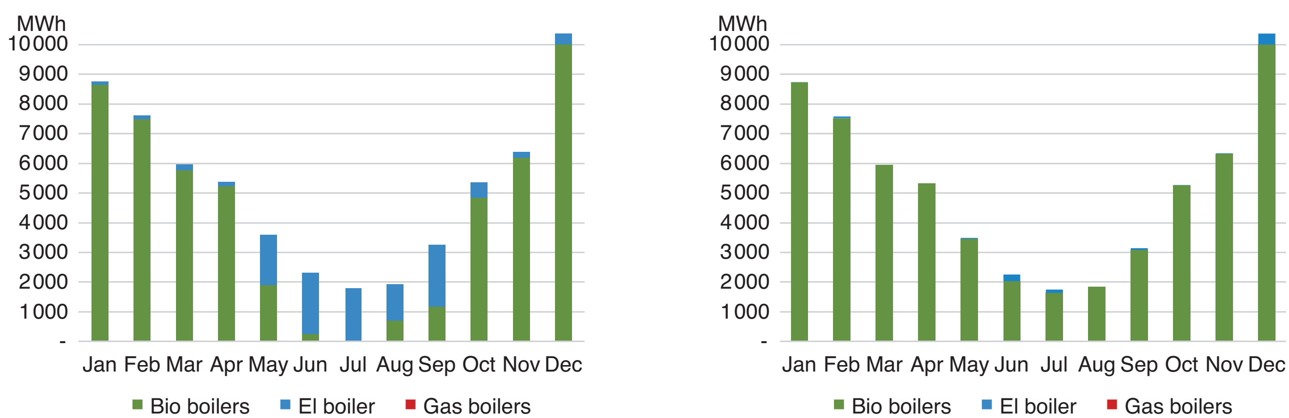


Figure 5: Use of boilers in the bio-based system with tank storage. The left figure shows a wet hydrological year whereas the right figure shows use of boiler under a dry hydrological year

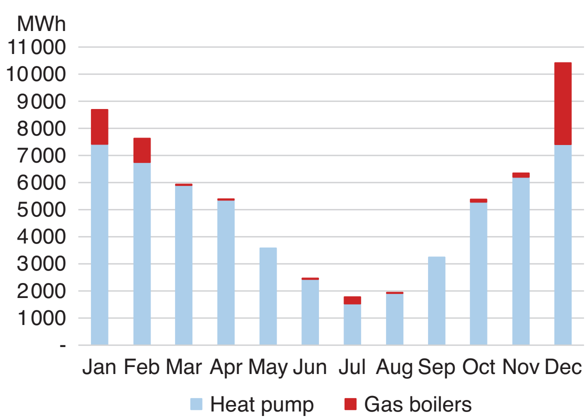
plant studied here by reducing the total el-grid tariff from 6.0 € /MWh to 3.0 €/MWh in a configuration without tank storage. The results regarding the use of boilers are shown in Figure 7. The grid tariff significantly influences the use of the electric boiler in wet years (2012 and 2030 Wet) as electricity becomes a cheaper fuel than biomass in a number of periods. In normal and dry years, electricity is still more expensive than biomass and continues to replace mainly LPG at peak load.

5. Discussion

The future electricity price level is a result of several assumptions, of which the carbon and fuel prices are particularly decisive factors. The three electricity price scenarios investigated in this study have annual average prices of 24 €/MWh, 34 €/MWh and 49 €/MWh for the wet, normal and dry inflow scenarios, respectively. The electricity price scenarios investigated in this study is found to be well in line with projections made in previous studies. In the recent Nordic Energy Technology Perspectives study (IEA, 2016), the 2030 price in Norway is modelled to be 50 €/MWh, based on a strong increase in the CO_2 price to about 80 € /t in 2030. Other recent studies of the future electricity price report Norwegian 2030 prices that vary from 34 €/MWh to 56 €/MWh, all assuming normal inflow levels [41-43]. This study demonstrates that both the level and the short-term variation of the electricity price are decisive factors for the operation of electric boilers in district heating systems. Although much emphasis has been given in this study to investigate the most likely assumptions on the market-driving developments, the assumptions for the electricity market simulations for 2030 are associated with a high degree of uncertainty.

Table 12: Profitability and use of boilers in the heat pump system with thermal storage

Scenario	Normal 2030, no electric boiler	Normal 2030 with electric boiler	Wet 2030, no electric boiler	Wet 2030 with electric boiler	Dry 2030, no electric boiler	Dry 2030 with electric boiler
Gross income(1000 €)	3,990	3,990	3,460	3,460	4,740	4,740
EBITDA (1000€)	2,300	2,460	1,970	2,170	2,770	2,870
Heat supply heat pump	91.1%	89.5%	91.2%	89.0%	91.1%	90.6%
Heat supply electric boilers	–	9.5%	–	10.1%	–	8.2%
Heat supply gas boilers	8.9%	1.0%	8.8%	0.9%	8.9%	1.2%



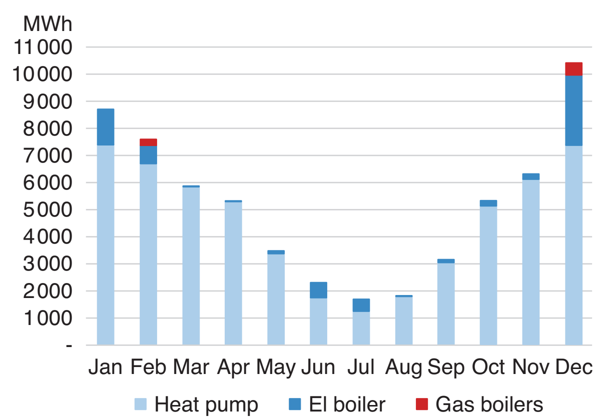


Figure 6: Use of boilers in the heat pump system in 2030, normal electricity price scenario. Left figure shows heat production with storage and no electric boiler, right figure shows heat production with storage and electric boiler. Maintenance of the heat pump causes use of gas or electric boiler in July

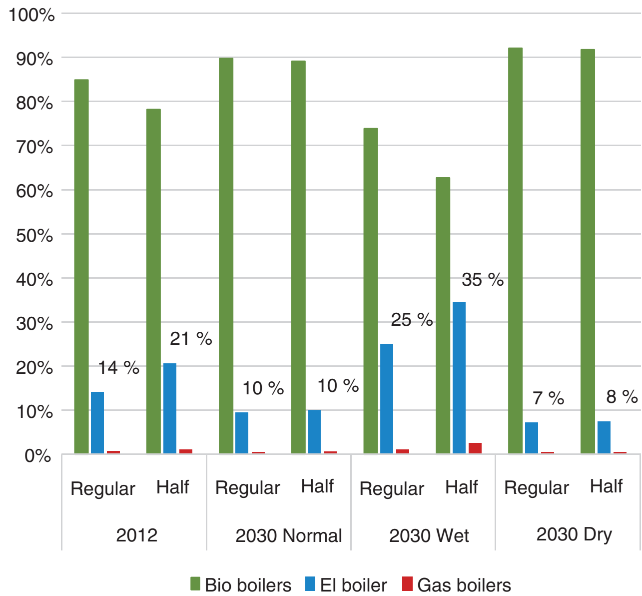


Figure 7: Use of a boiler in the bio-based system without storage with regular (6.0 €/MWh) and half (3.0 €/MWh) grid-tariff for the electric boiler. The electric boiler's share of the annual heat production is labeled

We identify five major price drivers that are particularly important for the development in the electricity market, based on previous literature, the historical market development, the current market, and policy conditions, as well as various model-sensitivity analyses:

(1) The CO_2 price, which affects the costs of fossil fuel electricity generation, and has varied from close to zero to more than 30€/t historically.

(2) The fuel prices, which also affect costs of fossil fuel electricity generation, and influence the electricity price level.

(3) The nuclear power capacities in Sweden, which has provided some 60–70 TWh base load to the Nordic power market annually (corresponding to 15–20% of total consumption). All the 11 reactors currently in operation will have to reinvest to remain in operation in the coming 10–15 years.

(4) The annual electricity consumption, which has lingered just below 400 TWh in recent years, but which may increase or decrease in the long run, depending on the strengths of various consumption drivers. Also, we may experience changes in seasonal and diurnal consumption patterns.

(5) The growth of VRE which has been very high in recent years, and which is expected to increase strongly up to 2030. The VRE shares have a strong influence on the short-term price variation.

These uncertainties imply that the electricity price scenarios in this study have a high uncertainty. Nevertheless, the general trends, for example the assumption of a higher integration between the Nordic and Continental power markets, and the expectations of higher short-term price variation with increasing VRE shares, are regarded as robust.

The Balmorel model has the capability to analyze the effect of key drivers in the North European power market on an hourly basis, which is important for analyses of flexibility options in the district heating sector. [44] point out that deterministic models overestimate the value of heat pumps and electric boilers. However, by comparing modelled and observed prices for the year 2012 (Figure 3), we observe that modelled electricity prices have less variability than the observed prices. This indicates that the value of electric boilers – which benefit from increased variability in electricity prices – may actually be higher than estimated in this study. The perfect foresight implied in energyPRO might exaggerate the actual switch to electricity, even if can to some extent be adjusted for by including ramping assumptions or start-stop costs.

The use of the optimization model Balmorel and the simulation model energyPRO combines two different approaches. Electricity prices are decisive factors for the use of electricity in heat plants. Market equilibrium models like Balmorel are suitable for the modeling of market prices, whereas simulation models like energyPRO provide modules for detailed simulation of plant-level operation. Results from plant-level simulations can be used to improve the specifications of technologies in the market model to ensure better modelling of market behavior.

Heat demand is assumed to be independent of electricity prices in this analysis. Low hydrological inflow is often related to low temperatures and consequently higher heat demand. Similarly, high hydrological inflow is often associated with lower temperatures. This correlation between inflow and heat demand is not analyzed in this study. Due to the high use of electricity for heating in Norway, district heating prices are closely linked to Norwegian electricity prices. In countries where the alternative heating system is currently oil or gas, the district heating prices will, in the short run, be more independent of the electricity price.

The results show that tank storage, which is currently only installed in a few district heating plants in Norway, is a profitable option that will significantly reduce the use of fossil peak load in both bio-based and heat-pump-based systems. The capital costs for tank storage in Norway shown by [39] seem to be high compared to costs in countries where thermal storage is more common (see e.g. [45]) and could therefore be expected to decrease as more thermal storage is installed. Increased use of heat storage in the Nordic energy system is also proposed by [46].

Installation of an electric boiler in addition to tank storage is profitable in the analyzed heat pump system. In the bio-based plant, an electric boiler in addition to tank storage is only profitable when electricity prices are low, as in the wet inflow scenario when electricity will replace both gas and parts of the biomass. The actual use of electricity in a heat-only district heating system will depend on various factors, like boiler capacity, heat demand, fuel prices, storage options, start-up costs, and ramping constraints. A heat pump instead of an electric boiler to supplement the biomass boiler in the bio-based plant will give lower electricity costs. Heat pumps, however, require significant investment costs and need higher utilization rate/load factor to be profitable. Heat pumps are therefore less flexible than electric boilers as supplementary load and peak load, as also pointed out by [16]. Heat pump systems can be cost effective, as illustrated by [17], but flexible operation requires that the heat pump can take a large share of the load.

The results in this study are relevant for heat-only plants of both smaller and larger scale in the North European countries with integrated power markets. Exact figures will depend on the actual plant configuration and fuel prices. In countries with low natural gas prices, the use of storage or electricity is less profitable than in the case studies shown here, especially if electricity grid costs and taxes are high. The impacts of grid tariff structures for flexible operation of electric boilers are analyzed more in detail in [47]. Utilization of flexible options in district heating systems requires grid tariff levels and structures for electricity use in flexible heating that to a greater extent benefit the use of electricity. As shown in this study, lower grid costs in flexible heating plants will increase the use of electric boilers in district heating systems.

6. Conclusions

Future electricity prices are decisive for profitable use of electricity in district heating systems. The electricity price level is expected to increase towards 2030 due to higher fuel and carbon prices. At the same time, the short term price variation will likely increase as a result of higher shares of VRE. The expected changes in price levels and variation impact the optimal investments and operation of district heating plants. In a plant using bioenergy as base load we find that the use of tank storage can, to a large extent, replace the use of fossil peak load, when assuming electricity prices in accordance with a "most likely" power market development scenario. Investment in both storage and electric boilers is only profitable in a high inflow scenario that causes relatively low electricity prices (annual average of 24 €/MWh) or with reduced electricity grid rent. In a plant with heat pump as base load, we find that investment in an electric boiler in addition to tank storage is profitable in all electricity price scenarios and will, to a large extent, eliminate the use of gas in the assumed configuration. The results show how increased variability and periodically low electricity prices can imply increased use of power to heat. However, electricity grid tariffs and taxes are decisive factors for a system-friendly use of electricity in heat-only district heating plants.

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Appendix 1.

Mathematically, this can be expressed by an objective function subject to a number of constraints. The objective function maximizes a consumer's utility function minus the cost of electricity generation, transmission, and distribution. (In this study we assume inelastic electricity demand; hence, maximizing utility is equivalent to minimizing total system costs):

$$max\left[\sum_{s\in S}\sum_{t\in T}\sum r\in R(C)\left\{\begin{array}{l} D_{r,t,s}\left(d_{r,t,s}\right)- \\ \left(\begin{array}{l}\sum_{i\in I}K_i^P\left(g_{r,i,t,s}\right)+ \\ \sum_{A\in R,A\neq r}K_{A,r}^T \\ \quad\left(X_t^{(A,r)}\right)+K^D \\ \sum_{i\in I}g_{r,i,t,s}\end{array}\right)\end{array}\right\}\right] \quad (1)$$

The total power demand is determined exogenously for each region. The hourly variation in power demand is set equal to the observed hourly consumption profiles in 2012, scaled according to the total annual power demand of the year to be studied. There is no endogenous substitution between demands in the different periods or between different geographical units, and an energy-balance constraint ensures that power supply must equal demand in every time step:

$$\sum_i g_{r,i,t}+\sum_{A\in R,A\neq r}\left(X_t^{(A,r)}-X_t^{(r,A)}\right)=d_{r,t},\forall i\in I \quad (2)$$

The model includes costs and losses of electricity distribution within each region, with the assumption of no constraints on electricity flow within a region. Hourly trade with third countries is determined exogenously, while the power exchange between model countries is determined endogenously, with restrictions on transmission capacities between regions:

$$X_t^{(A,B)}\leq\overline{X}_t^{(A,B)},\forall A,B\in R,A\neq B \quad (3)$$

The equilibrium conditions between each geographical region will hence depend on the specified transmission conditions. The supply side includes various generation technologies and fuels. Each generation technology has a specified fuel type, fuel efficiency, variable and fixed costs, heat/power combination factor (if CHP unit), and an environmental characteristic. The maximum capacity level from a specific generation unit is defined by:

$$g_{r,i}\leq\ \bar{g}_{r,i} \quad (4)$$

The variation in marginal costs from thermal power production is handled in two ways in the model: First, each thermal technology type is divided into four sub-technologies, with different fuel efficiency levels and variable production costs, representing the cost of old, average, new, and future power plants. Second, limits on thermal flexibility are included by letting each sub-technology (i_{TH}) be represented by J = 3 ramping conditions ($g^*_{r,iTHj,t}$) such that:

$$g_{r,iTH,t}=\begin{cases}g^*_{r,i_{TH_1},t}\\ g^*_{r,i_{TH_2},t}\\ g^*_{r,i_{TH_3},t}\end{cases}\quad ,where\quad \sum_j g^*_{r,iTHj,t}=g_{r,iTH} \quad (5)$$

In each ramping condition, the sub-technology will have a different capability of ramping power up or down from one hour to the next, with increasing variable cost for increasing ramping capability:

$$\begin{array}{l}g^*_{r,iTHj,t}-g^*_{r,iTHj,t-1}\leq\overline{ramp}_{iTHj}\cdot\bar{g}_{r,iTH}\\ g^*_{r,iTHj,t}-g^*_{r,iTHj,t-1}\geq\overline{ramp}_{iTHj}\cdot\bar{g}_{r,iTH}\end{array} \quad (6)$$

Increased need for ramping from one hour to the next will then force the model to select a more expensive ramping condition of the sub-technology, inducing an increasing per-MW ramping cost with increasing levels of ramping. Thereby, the model is able to reflect the cost of varying thermal power output on an aggregated level.

For some technologies (nuclear power, CHP units) seasonal minimum and maximum production levels are defined as:

$$\underline{g}_{r,i,s}\leq\underline{g}_{r,i,s}\leq\underline{g}_{r,i,s} \quad (7)$$

Intermittent RE sources (i_{IM}) (wind power, solar power, and run-of-river hydropower) have exogenously given production profiles varying on an hourly level according to variations in wind speed, sun light intensity, and run-of-river water flow:

$$g_{r,iIM,t} \leq \bar{g}_{r,iIM,t} \tag{8}$$

For reservoir hydro, power generation is also limited by a reservoir equation (Equation 9), stating that the hydro resource level at the end of period s is equal to the hydro resource level at the end of the previous period plus the inflow, minus total hydropower production during period s. Minimum and maximum restrictions on the hydro reservoir storage level (Equation 10), start level for the hydro reservoirs (Equation 11), and seasonal restrictions on the water flow through the hydro turbines (Equation 12) constitute the hydropower dynamics:

$$v_s \leq v_{s-1} + \omega_s - \sum\nolimits_{t \in T} g_{r,iHY}, t, s \tag{9}$$

$$\underline{v_r} \leq v_{r,s} \leq \overline{v_r} \tag{10}$$

$$\underline{v_{or}} \leq v_{r,s=1} \leq \overline{v_{or}} \tag{11}$$

$$\underline{g}_{r,i_{HY},s} \leq \underline{g}_{r,i_{HY},s} \leq \bar{\underline{g}}_{r,i_{HY},s} \tag{12}$$

Pumped storage is included in the model by adding the following sections to Equations 2 and 7:

$$\begin{aligned} &\sum\nolimits_i g_{r,i,t} + \sum\nolimits_{A \in R, A \neq r} \left(X_t^{(A,r)} - X_t^{(r,A)} \right) = d_{r,t} \\ &\quad + d_{r,t}^{pump} = d_{r,t}^{total}, \forall i \in I \end{aligned} \tag{2.2}$$

$$\begin{aligned} &v_s \leq v_{s-1} + \left(\omega_s + \boldsymbol{\omega_s^{pump}} \right) - \sum\nolimits_{t \in T} g_{r,iHY,t,s} = v_{s-1} \\ &\quad + \boldsymbol{\omega_s^{total}} - \sum\nolimits_{t \in T} g_{r,iHY,t,s} \end{aligned} \tag{9.2}$$

where ω_s^{pump} is the water amount (measured in energy units) pumped back to the hydro reservoirs and $d_{r,t}^{pump}$ is the energy used for pumping in hour t, such that:
γ^{pump} is the assumed pumped-storage energy efficiency, which is set to 75% in this study.
Finally, we have the non-negativity restrictions:

$$X^{(a,b)},\ g,\ d, v,\ \omega \geq 0 \text{ for all R, T, S, and I.} \tag{13}$$

Appendix 2. New interconnectors

Project	Capacity	Year	From - to region
Southwest link	1200	2020	Eastern Norway - south mid Sweden
NordLink	1400	2019	Southern Norway - Germany
NSN interconnector	1400	2021	Southwestern Norway - UK
Kassø-Flensburg-Dollern	1500	2020-2025	Western Denmark - Germany
Krigers Flak	400	2019	Eastern Denmark - Germany
Cobra Cable	700	2020	Western Denmark - Netherlands
DE - NE Strengthening	2000	2017-2018	Germany - Netherlands
Vinking link	1400	2022	Western Denmark - UK
NorNED 2	700	2025	Southern Norway - Netherlands