Energy Policy 106 (2017) 85–102

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

The impact of policy actions and future energy prices on the cost-optimal development of the energy system in Norway and Sweden

Pernille Seljom[a,b,*], Asgeir Tomasgard[a]

[a] Department of Industrial Economics and Technology Management, Norwegian University of Science and Technology (NTNU), 7491 Trondheim, Norway
[b] Department of Energy Systems, Institute for Energy Technology (IFE), Post box 40, 2027 Kjeller, Norway

ARTICLE INFO

Keywords:
TIMES
Stochastic programming
Hydropower
Energy system
Intermittent electricity generation
Renewable energy
Investment model

ABSTRACT

This paper studies the effects of policy actions on the energy systems in Norway and Sweden, including a nuclear shutdown, a cancelation of restricted hydropower and an expansion of export capacity to Europe. This study apply a stochastic TIMES model that considers the short-term uncertainty in electricity supply and value the flexibility of hydro reservoirs. It is the first time this approach is used to quantify the effects of these policy actions on cost-optimal investments and operations. To consider the uncertainty of the energy market, we analyse the policy actions under four different price developments for biomass, fossil fuels and electricity. The results demonstrate that our stochastic approach provides different model decisions compared to the traditional deterministic approach. Further, we show that the future role of the large hydro reservoirs in Norway and Sweden depends both on the adopted policy actions and on future energy prices, and that the policy actions have a significant impact on the development of the energy system. This insight is valuable when considering the development and management of the hydro reservoirs. It is also valuable for other European countries so that they can evaluate the interplay of the hydro reservoirs with other energy storage options.

1. Introduction

Insights from energy system investment models contribute to a cost-effective development of the system and illustrate the long-term impact of energy and environmental related policies. For Norway and Sweden, it is essential to use tools that consider the flexible hydro production in the light of the increased share of intermittent renewable electricity generation in Europe. Although Norway and Sweden are two relatively small countries, the energy-related decisions in these countries can have a significant impact on the European energy system. Norway and Sweden have about 70% of the European hydro reservoir capacity, at 82 TWh and 34 TWh respectively (Nord Pool Spot, 2014), and are highly interconnected to northern Europe. However, the contribution of the hydro flexibility is uncertain in both the short and long term since it relies on the climate dependent hydro inflow and on the future development of the energy system.

This paper use a stochastic TIMES model (the Integrated MARKAL-EFOM System) (Loulou, 2008; Loulou and Labriet, 2008; Loulou et al., 2005a, 2005b, 2005c), with an explicit modelling of the short-term uncertainty related to electricity supply, to study the effects of important energy and environmental policy actions on the energy systems in Norway and Sweden from a social welfare perspective. The policy actions include a nuclear shutdown, a cancellation of restricted hydropower and an expansion of export capacity to Europe. For comparison, we also include a benchmark case, with no political action taken on these issues. Further, we analyse these policies under four different assumptions on price development on biomass, fossil fuels and electricity outside Norway and Sweden. Consequently, we can indicate the key impact of the policies under different market assumptions.

The first contribution of this paper is analysis of the impact of the selected policy actions on the energy sector in Norway and Sweden. For the various policy actions and energy price assumptions, we present investments and operation in the energy sector towards 2050, including the handling of flexible hydro reservoirs, development of renewable electricity generation, heating technologies in buildings and the interaction with the European electricity market. This insight is valuable for decision makers in Norway and Sweden in order to design policy instruments that give optimal investments, from a macroeconomic perspective. As the policy actions influence the future interaction with the European electricity market, their implications are also interesting for decision makers located outside the borders of Norway and Sweden.

Abbreviations: CHP, Combined Heat and Power; DH, District Heat; EMPS, Multi-area Power-market Simulator; PV, Photovoltaic Power; ROR, Run-Of-the-River; TIMES, The Integrated MARKAL-EFOM System; VSS, Value of Stochastic Solution

* Corresponding author.
E-mail addresses: pernille.seljom@ife.no (P. Seljom), asgeir.tomasgard@iot.ntnu.no (A. Tomasgard).

http://dx.doi.org/10.1016/j.enpol.2017.03.011
Received 19 February 2016; Received in revised form 27 February 2017; Accepted 3 March 2017
0301-4215/

For northern Europe, the possible contribution and role of the flexible hydro reservoirs in Norway and Sweden should be evaluated together with alternative back-up technologies and other energy storage options for an optimal integration of intermittent electricity generation.

The second contribution of this paper is the applied stochastic methodology, which provides investment decisions that take into account a range of operational situations that can occur. We include a stochastic representation of the short-term uncertainty of hydropower, wind power and electricity trade prices outside Norway and Sweden in order to consider the uncertainty of intermittent electricity supply. Here, the stochastic electricity trade prices represent the short-term uncertainty of the market equilibrium in the countries with interconnection to Norway and Sweden. Our analysis shows that a stochastic modelling approach, with a more realistic representation of electricity sector, provides different investment strategies compared to a deterministic representation of the intermittent electricity supply.

The policy on a nuclear shutdown is included as the future of nuclear power is uncertain due to the political agenda of some parties (Qvist and Brook, 2015). The taxation of the nuclear capacity and subsidised renewable electricity generation are current policy instruments that reduce the profitability of nuclear power. The Swedish tax on nuclear capacity, which is justified to cover future decommission costs, was increased to 14770 SEK per MW and month (corresponding to EUR 1507 with 9.8 SEK/ EUR), by 1 August 2015 (Regeringskansliet, 2015). After this tax increase, it was agreed to shut down the two oldest reactors at Ringhals and the two oldest reactors at Oskarshamn from 2015 to 2020 (Fortum, 2015; Vattenfall, 2015) in October 2015. This resulted in a 25% reduction in the Swedish nuclear capacity to 6.7 GW (Svensk Energi, 2015). Consequently, further taxation can result in no nuclear power generation in Sweden. A possible absence of the Swedish base load nuclear power supply can influence the available hydropower flexibility to Europe. For example, if the nuclear capacity is replaced by wind power, the hydro reservoirs can be used to a larger degree as back-up capacity within Norway and Sweden in periods with poor wind conditions.

We include the environmental policy on an expansion of the Norwegian hydro potential because the development of a large part of the potential new hydro plants in Norway is restricted by the Protection Plan for Watercourses. The protection was adopted by the Parliament from 1987 to 1995 (NVE, 2015c), and is reasoned by the environmental impact of landscape and biodiversity. A cancelation of the restrictions can cause intervention in untouched natural areas and increases the new hydro potential from 31 TWh to 80 TWh (NVE, 2015b). Although, a cancelation of the restriction has not been on the political agenda, it is relevant with increased focus on a sustainable development. For an overall assessment, this restriction should be evaluated against the environmental impact of other electricity generation technologies, such as wind power and fossil fuelled plants. Also, the value of the flexible hydro plants can significantly increase with more intermittent electricity generation since the additional flexible hydro capacity can give increased profits for Norway and Sweden.

Electricity exchange with other European countries is a prerequisite for best utilisation of the hydro reservoirs with regard to profit. Building new export capacity from Norway and Sweden to Europe is being debated. This includes the capacity expansion projects, "NSN Link" between Norway and the United Kingdom (Statnett, 2015b) and"NordLink" between Norway and Germany (Statnett, 2015a). To expand or not, is both an energy policy decision and a matter of environmental concern. The Norwegian debate on expanding the export capacity to Europe is mainly based on the effect on domestic electricity prices and on the influence on the domestic power grid (Mo Industripark AS, 2015; Stavrum, 2015). If additional trade capacity increases the electricity prices, it can threaten the competiveness of the power intensive industry. Also, more cables out of the country can require domestic grid reinforcements in untouched natural areas. On the other hand, more export capacity can increase the value of the hydro flexibility and result in additional profits for the hydro plant and public transmission owners.

Energy models are commonly used to evaluate the cost-optimal adaption of policies that deals with environmental considerations and the transition to a sustainable energy system in Europe. For models with focus on Norway and Sweden, it is mainly the modelling tool Multi-area Power-market Simulator (EMPS) (Warland et al., 2008; Wolfgang et al., 2009), BALMOREL (Ravn, 2001, 2011) and TIMES that is used. A selection of related literature that applies these modelling tools is presented below. A generic description of long-term energy models are given in Section 2.1.

For the Nordic countries (Norway, Sweden, Denmark, Finland and Iceland), the adaption of the power system towards 2050, given the 2 degree scenario in ETP 2016 (IEA, 2016a), is analysed by a BALMOREL model in IEA (2016b). Here, the climate scenario is achieved with inter alia an extensive development of wind power, increased transmission capacity to other European countries and more district heat production from heat pumps. A key finding is that the Nordic region is capable of integrating a large share of intermittent electricity generation due to the flexible hydro production and the integrated electricity market. This study also addresses the uncertainty of the future Swedish nuclear capacity, and presents the impact of a nuclear phase-out by 2030. Their results show that a decommissioning of nuclear power in Sweden increases the investments in wind power and natural gas power plants, decreases the Nordic electricity production and decreases the electricity export.

The influence of various policy routes on the development of the low-carbon power technologies in the European energy system, is analysed with a TIMES model in Simoes et al. (2016). This study concludes that a decarbonisation of the electricity sector in the European Union is achievable with an increased share of renewable electricity generation, nuclear and carbon capture and storage. Further, this paper demonstrates that the investments in renewable electricity generation technologies decreases with a higher social acceptance of nuclear power plants and increases with a higher number of available sites for renewable production. The uncertain role of nuclear power, related to costs and public acceptance, is also addressed in Fais et al. (2016), that uses a TIMES model to study the impact of technology uncertainty in the decarbonisation of the United Kingdom. A conclusion from this study is that a replacement of nuclear capacity with other low-carbon electricity options does not increase the electricity generation cost significantly.

The economic impact of the interconnector between Norway and United Kingdom is analysed with EMPS in Doorman and Frøystad (2013). A conclusion from this work is that this interconnector is in general profitable from a social welfare perspective. Using the same framework, Kjetsa and Mo (2015) shows that the profitability of interconnections from Norway to Germany and the United Kingdom, and the value of the hydro flexibility, increases with uncertain fuel prices.

The outline of the paper is as follows: Section 2 sets the context of the analysis by describing long-term energy models and the energy systems in Norway and Sweden. Section 3 is devoted to the applied methodology, including a description of the TIMES model and the stochastic model approach. Section 4 describes the combination of policy actions and energy price assumptions that is used for further analyses. Finally, the results are presented in Section 5, and the conclusions and policy implications are given in Section 6.

2. Background

The purpose of this section is to set the context for our analyses. First, we categorise various long-term energy models to justify the use of TIMES in this study. Thereafter, we give a brief description of the energy systems in Norway and Sweden with focus on the electricity sector, as this sector is most sensitive for the policy actions.

2.1. Long-term energy models

There are numerous different long-term energy models, with various characteristics, and several studies are dedicated to categorise and compare these models, including (Bhattacharyya and Timilsina, 2010; Connolly et al., 2010; Després et al., 2015; Pfenninger et al., 2014). Long-term models of the energy sector are split between bottom-up models, with a technical description of supply and demand, and top-down models, with a description of macro-economic relationships. This section presents various properties of bottom-up models related to sectoral coverage, investment strategy and short-term uncertainty.

2.1.1. Sectoral coverage

Bottom-up models can be categorised by its sectoral coverage. While some models only cover a sub-system of the energy sector, as the electricity sector, other models covers multiple energy sectors, hereby denoted energy system models. The advantage with a wider sectoral coverage is that this approach can capture the interaction between the various sectors. Energy system models can thus quantify the impact of policy actions on the optimal use of electricity in all energy sectors as the final electricity consumption is a model result and not a model input. Commonly used energy system modelling tools includes TIMES/ MARKAL, BALMOREL, MESSAGE (IIASA, 2012), OSeMOSYS (Howells et al., 2011), PRIMES (NTUA, 2016) and POLES (Enerdata, 2016). Note that TIMES is the successor and the enhanced version of MARKAL. Among these energy system models, BALMOREL is developed to cover the electricity and Combined Heat and Power (CHP) sector whereas the other models can cover all energy sectors including electricity, buildings, transport and industry.

Electricity sector models, with an exogenous electricity demand, often have a higher detail level of the power sector compared to energy system models. For example, the power sector modelling tool PLEXOS (Energy Exemplar, 2016) enables a high time resolution and includes integer properties like ramping, start-up costs and minimum up time that is normally neglected in long-term energy models. Another electricity model is EMPS, a detailed operation model of electricity markets with stochastic hydro inflow. This model is inter alia used for hydropower scheduling and electricity price forecasting in the Nordic power market.

According to Després et al. (2015), no current energy system model has the necessary temporal resolution to represent the constraints related to an integration of intermittent electricity generation, and long-term energy system models would benefit from a more accurate representation of the electricity sector. Consequently, understanding the impact of the simplified electricity sector will improve the insights provided by energy system models. In Deane et al. (2012), the model decisions from a deterministic Irish TIMES model is evaluated with results from a PLEXOS model to evaluate the appropriateness of the electric generation capacity. Deane et al. (2012) show that the TIMES model provides a reliable electricity generation but undervalues flexible elements and underestimates wind curtailment.

2.1.2. Investment strategy

The investment strategy of bottom-up models can be split between a myopic and a perfect foresight approach. With a myopic approach, the investment decisions are only based on the prices and demand of the investment period. Consequently, these investments suppose that the market conditions remains unchanged throughout the lifetime of the investment. This is on the other hand not the case for a perfect foresight approach, where investments are made with full knowledge of the future evolvement of the energy system. As policy action can influence the energy market in both the short-term and long-term, a perfect foresight approach is a suitable tool to analyse the cost-optimal adaption of policies over a longer time horizon.

Among the energy system models, the investment algorithm in BALMOREL and POLES are myopic, PRIMES apply perfect foresight over a limited time horizon, e.g. ten years, whereas MESSAGE, OSeMOSYS and TIMES have a perfect foresight investment strategy. Also, the investment algorithm to the electricity model EMPS is myopic (Jaehnert et al., 2013).

2.1.3. Representation of short-term uncertainty

The short-term uncertainty in energy models can be represented by a deterministic or a stochastic approach. Short-term uncertainty is characterised by conditions that are periodically recurring, as hydro inflow, wind speed, temperatures and fluctuations energy prices. A stochastic approach provides cost-optimal investment decisions that are valid for a range of representative operational situations that can appear, given the presence of short-term uncertainty. This is opposed to a deterministic approach, where the investments are based on only one operational scenario. Consequently, given the unpredictable characteristics of renewable electricity generation, a stochastic approach gives a more realistic representation of the intermittent electricity generation than a deterministic approach.

As we know, TIMES is the only energy system model that has an established methodology to represent short-term uncertainty by stochastic programming. It is also an option to model the uncertainty related to technology costs and carbon price in MESSAGE stochastically (Krey and Riahi, 2009). Stochastic modelling of short-term uncertainty in TIMES is introduced in Loulou and Lehtila (2012), is documented and applied in a user guide in Nijs and Poncelet (2016), is used to model the intermittent characteristics of wind power in Denmark (Seljom and Tomasgard, 2015) and is applied to evaluate the impact of Zero Energy Buildings in the Scandinavian energy system in Seljom et al. (2017). Note that the majority of the TIMES literature, including (Daly et al., 2014; Fais et al., 2016; IEA, 2013, 2016a; Kannan and Turton, 2012; Krook Riekkola et al., 2011; Lind et al., 2013; Rosenberg et al., 2013; Shi et al., 2016; Vaillancourt et al., 2014; Zhang et al., 2016), represent the short-term uncertainty by a deterministic approach. This implies that the results obtained from these models do not directly take into account the uncertainty of intermittent electricity generation and value flexibility different than a stochastic approach. As demonstrated in Seljom and Tomasgard (2015), the deterministic modelling approach can influence the model result. This study concludes that the method used to represent the unpredictable characteristics of wind power in investment models can significantly affect the model results.

There are however studies, focusing only on the electricity sector, that have incorporated a stochastic modelling of intermittent renewables in investment models. For example (Nagl et al., 2013) apply stochastic modelling of wind power and Photovoltaic Power (PV) in a combined investment and dispatch optimisation model of the European electricity market. Their results demonstrate that intermittent renewables are significantly overvalued, flexible energy technologies are underestimated and that the total system cost is significantly underestimated in deterministic electricity models. Other work includes (Munoz et al., 2014; Nagl et al., 2013; Skar et al., 2014a, 2014b; Spiecker et al., 2013; Sun et al., 2008).

2.2. The energy system in Norway and Sweden

Norway and Sweden are the countries with the largest national electricity generation from hydropower in Europe, where the hydro share in the electricity generation mix was 96% for Norway and 41% for Sweden in 2013 (Eurostat, 2015). Further, the nuclear power plants located in south-eastern Sweden; Forsmark, Oscarshamn and Ringhals, contributed to 42% of the Swedish electricity generation (Eurostat, 2015). The remaining electricity generation is primarily wind power and CHP.

The electricity market in the two countries is highly integrated with each other and the European electricity market. Externally, Norway is

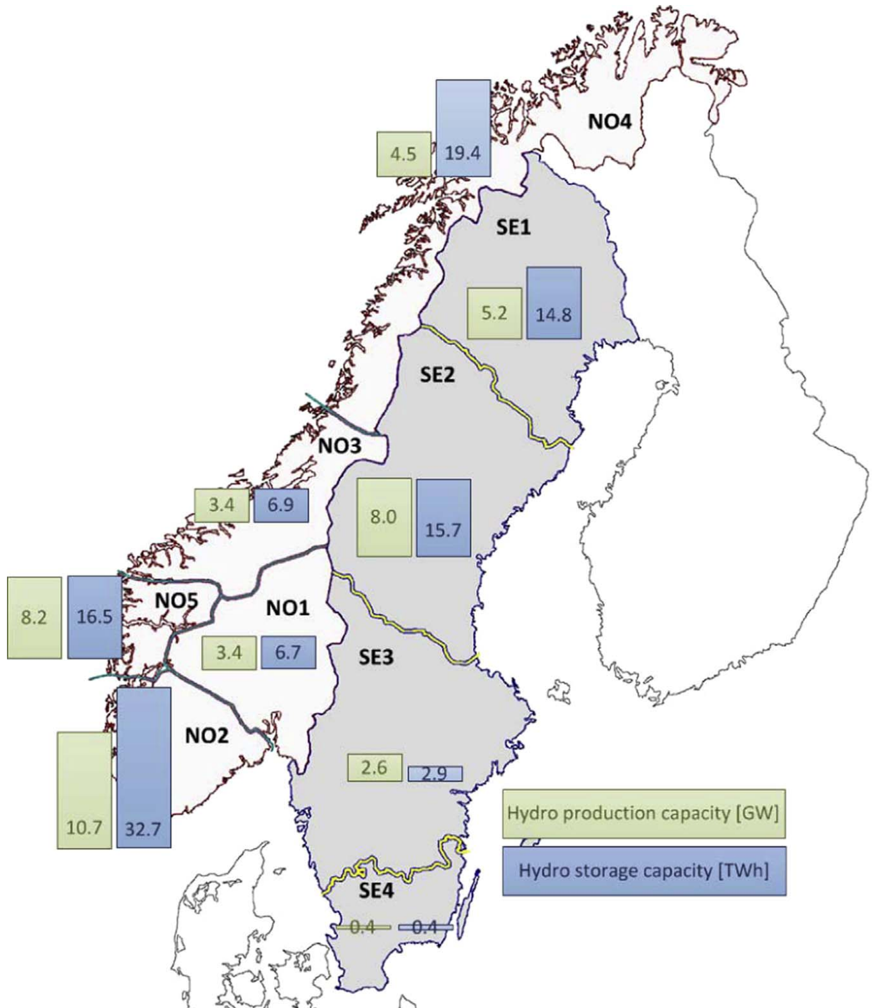


Fig. 1. Map of Norway and Sweden, divided by price area, with indication of hydro production and storage capacity.

currently connected to Denmark, Finland, the Netherlands and Russia while Sweden is connected to Denmark, Finland, Germany and Poland with a capacity expansion to Lithuania under construction. The two countries are a part of the Nord Pool Spot power market, where Norway is divided in five electricity price areas, NO1-NO5, and Sweden is split in four electricity price areas, SE1-SE4. For a given hour, the electricity price is identical within each price area, while the electricity price can be different for the various price areas due to bottlenecks in the transmission grid. Historically, the geographical boundaries of the price areas have changed to improve the congestion management, and in this paper we use the area definition according to 2013-12-02 (Statnett, 2013; Svensk Energi, 2012).

A map of the Nord Pool price areas in Norway and Sweden, with hydro production- and hydro storage capacities is illustrated in Fig. 1. The hydro production capacities are provided by the Norwegian Resource and Water Directorate (NVE) for Norway, and are available in (Svensk Energi, 2014) for Sweden. The hydro storage capacities are provided by Nord Pool. The hydro production capacity is about double the size in Norway at 30.2 GW compared to Sweden at 16.2 GW, and the national hydro storage capacity is 82.2 TWh and 33.7 TWh respectively. In Norway, the price area located in the south, with European transmission capacity Denmark and the Netherlands, NO2, has the highest production- and storage capacity at 10.7 GW and 32.7 TWh. The situation in Sweden is that the price area located in the middle of the country, SE2, with electricity exchange to price areas in Norway and Sweden, has the highest hydro production and storage capacity at 8.0 GW and 15.7 TWh respectively.

As of 2014-01-01, the expected Norwegian annual hydro production is 131.4 TWh and the new potential, excluding potential that is restricted due to nature conservation, is 31.5 TWh (NVE, 2015a). The expected hydro production in Sweden is 65.5 TWh (Svensk Energi, 2014), and according to Statens energimyndighet (2014), the potential for new hydro capacity in Sweden is in upgrading existing plants, with an estimate of 2.6 TWh. Since the hydro production both depends on the climate dependent hydro inflow and the operation of the hydro reservoirs, the expected production differs from the actual production. For example in 2014, the actual hydro production was higher than the expected value, with 136.0 TWh in Norway and 65.8 TWh in Sweden. Based on historical inflow and reservoir storage levels provided by (Nord Pool Spot, 2016), we derive the historical hydro production in Norway and Sweden, split by season, as presented in Fig. 2. Here the production ranges from 155 TWh in 1996 to 228 TWh in 2000, and is largest in winter and smallest in summer for most years.

Both the hydro inflow and the expectation of the electricity market, within and outside Norway and Sweden, are drivers for the flexible hydro production. This implies that the hydro production varies with the domestic electricity consumption and the electricity trade to Europe. Table 1 shows the annual electricity balance for Norway and Sweden jointly, from 2010 to 2014 with the respective hydro inflow and hydro production. Among these years, the net electricity trade ranges from 8 TWh import in 2010 - 38 TWh export in 2012, and the electricity consumption, including losses, ranges from 260 TWh in

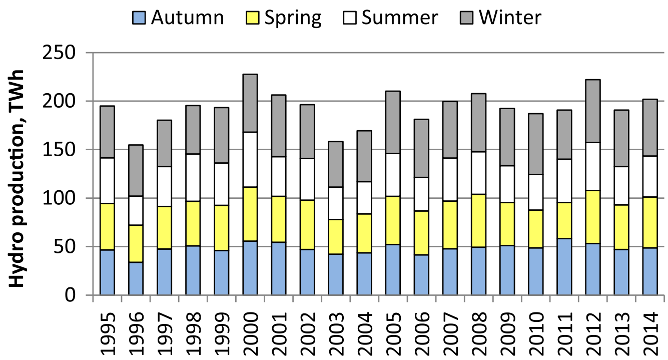


Fig. 2. Electricity generation from hydropower by season, 1995 – 2014.

Table 1
Annual electricity balance for Norway and Sweden from 2010 to 2014, with the respective hydro inflow and hydro production (Nord Pool Spot, 2016; Statistics Norway, 2016; Statistics Sweden, 2016).

Year		2010	2011	2012	2013	2014
Hydro inflow	TWh	164	230	211	189	200
Hydro production	TWh	187	191	222	191	202
Electricity generation	TWh	269	276	310	283	292
Electricity consumption	TWh	277	265	273	268	260
Net electricity export	TWh	−8	10	38	15	31

2014 to 277 TWh in 2010. Here, the hydro production, electricity generation and net electricity export to Europe is highest in 2012.

3. Methodology

This section is split in two. First, we give an overview of the model structure and assumptions of our TIMES model. Thereafter, we present the applied stochastic modelling approach, including the scenario generation of the uncertain parameters.

3.1. TIMES model structure and assumptions

TIMES is a bottom-up modelling framework, providing a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand from a social welfare perspective. It is mainly used for medium and long-term analysis on global, national and regional levels, including the Energy Technology Perspectives (IEA, 2016a). The model minimises the total discounted cost of the energy system to meet the demand for energy services for the analysed model horizon. The energy system cost includes investments in both supply and demand technologies, expenses related to operation of capacity, fuel costs, income from electricity export and cost of electricity import from external countries.

The model periods are every fifth year within the time horizon from 2010 to 2050. Further, each model period is divided into 48 time-slices, with a representative day with 12 two-hour steps in four seasons. The time-slice structure is chosen to capture the seasonal and diurnal characteristics of energy supply and demand. Winter is defined as December, January and February, spring is defined as March, April, May, summer is June, July and August and autumn is September, October and November. The model is regionally divided into the Nord Pool price areas, with five regions in Norway and four regions in Sweden, as illustrated in Fig. 1. The perfect foresight investment decisions are made in each model period, and operational decisions are made at a time-slice level. The operational decisions include activity level of each capacity type, fuel consumption and electricity trade. The annual discount rate is set to 4%, as used in Norwegian Government (2013). Further, we exclude current policy instruments, as taxes and subsidies, long-term climate goals and CO_2 price to obtain a true cost-optimal solution.

The future heat, transport and non-substitutable electricity demand is input to the model, and is based on the reference energy projections in Rosenberg and Espegren (2014) for Norway and from (Statens Energimyndighet, 2013; Statens Energymyndighet, 2012) for Sweden. The heat demand is divided into six different categories for Norway: commercial, single family house, multi-family house, metal industry, pulp and paper, and other industry, and into four different categories for Sweden; buildings, district heating (DH), forest industry and other industry. With the explicit modelling of the DH demand in Sweden, we do not capture the competition between DH and other heating options, for example if it is profitable to expand the DH grid to replace the natural gas grid. The maximum natural gas use is limited to the capacity of the natural gas grid, where we assume the current capacity is maintained towards 2050. The heat load profiles in the building sector are based on the methodology described in Lindberg and Doorman (2013).

The characterisation of energy technologies, as cost data and efficiencies, are input to the model and are primarily based on Lind and Rosenberg (2013), NVE (2015a). The model input on cost data of electricity generation technologies, indicating the range of investment, is given in Table 2. The model includes a set of technologies used to transform energy sources to final demand. This includes conversion processes such as electricity and heat production technologies, and demand technologies such as boilers and vehicles. It is optional to use electricity in heat and transport technologies and consequently the total electricity consumption is a model decision.

The transmission capacity within and outside the model region is a model input that is based on Nord Pool statistics. There are no investment options in new capacity besides the two capacity expansion projects to Europe between Norway and the United Kingdom, "NSN", and the electricity trade between Norway and Germany,"Nordlink". The on-going project from Sweden to Lithuania, "NordBalt", is a model input. The electricity trade is modelled in a simplified manner, without considering Kirchhoff's circuit laws, and the same capacity is used in both directions for Alternating Current cables. The electricity prices in the model regions in Norway and Sweden are endogenous, as they are the dual values of the electricity balance equation, while the electricity prices in the countries with trading capacity to Norway and Sweden is a model input. Further, we assume these electricity trade prices to be independent of the traded quantities to Norway and Sweden.

We model two types of hydro plants, Reservoir plants and Run-of-the-river (ROR) plants, by constraining the hydro production, and we do not explicitly model the hydro inflow and operation of the reservoirs. The plants are further divided into five different types; existing plants and four new plant options with different investment costs. The capacity for the existing plants is a model input whereas the capacity for the new plant options requires endogenous investments. For the ROR plants, the electricity generation is limited to a seasonal availability factor, a ratio of the seasonal hydro production over the

Table 2
Cost data for electricity generation technologies.

Technology	Investment cost MEUR/ GW	Annual fixed O & M cost MEUR/ GW	Variable O & M cost kEUR/ GWh	Lifetime Years
Reservoir hydro	1525 – 2563	15 – 25		40
ROR hydro	1635 – 3160	15 – 25		40
Wind power	1320 – 1611	–	19	20
Biomass CHP	1500 – 1902	33 – 84		25
Natural gas CHP	1188 – 1125	10 – 29		25
Waste CHP	2638	29		25
PV in 2015	2250	3		25
PV in 2050	1500	3		25

maximum theoretical seasonal production. Further, we assume the electricity generation from ROR to be identical for all daily periods within a season, and consequently these plants are assigned no production flexibility. As opposed to the ROR plants, the Reservoir plants are flexible between the time-slices of the model. The annual electricity generation from the Reservoir plants is constrained by an annual capacity factor, the annual production over the maximum theoretical production over a year. In addition, we constrain the seasonal electricity generation from the Reservoir plants to a maximum and a minimum production level according to historical observations.

The wind power is modelled by seven technology types with different costs and wind speed characteristics. This includes the existing capacity and six new onshore wind types.

The nuclear power is modelled as a base load plants by setting the electricity generation identically for all daily periods within each season. Further, the nuclear electricity generation is constrained by a maximum number of operational hours in each model period, ranging from 6745 h to 7796 h for the different plants. We do not take into account the cost of nuclear fuel and fuel handling of the nuclear plants. The reason for this assumption is that the nuclear power production can be a political decision, due to energy security, employment and high decommission costs, rather than a cost-optimal decision. For the same reason, the nuclear capacity is a model input and not a model decision.

3.2. Stochastic modelling approach

We apply a two-stage stochastic programming approach, where the uncertain parameters are represented by a discrete set of possible realisations, called scenarios (Kall and Wallace, 1994). This implies that the model decisions are split into two groups; first stage and second stage variables. The approach is designed such that the first-stage variables are made before knowing the outcome of the uncertain parameters whereas the second-stage variables are made for a best adaption of each scenario.

In our case, the first-stage decisions are investments in new capacity and the second-stage decisions are operational decisions. Consequently, the investments are identical for all scenarios, whereas the operational decisions are scenario dependent. To consider the different operational situations in the optimisation, our TIMES model minimises the investment costs and the average of the operational costs for all scenarios. This gives investment decisions that recognise the expected operational cost, and that are feasible for all the model specified realisations of the uncertain parameters. Note that the investment and operational model decisions are made simultaneously for all model periods, with operational decisions that are contingent on the realisations of short-term uncertainty. Hence, the investments consider the expected operational effects with the average taken over the scenarios. Further, we apply a multi-horizon model structure, with no dependency on the operational decisions between the model periods (Kaut et al., 2014). This simplification gives a significant reduction in model size, as it includes no learning effect over time from observing operational scenarios. This is done both because it simplifies computations, and because it provides a better approximation of real world decision processes. If such learning effects were included in the operational scenarios, it would be similar to assuming perfect foresight in the operations over the model life.

Historical data are used as a basis to sample 21 stochastic scenarios representing short-term uncertainty, with equal probabilities. The scenarios represent realistic outcomes of the uncertain parameters; hydro production, wind production and electricity trade prices. The number of scenarios is primarily chosen to ensure manageable computational time, even though a higher number of scenarios can increase the quality of the model results (Kaut and Wallace, 2007). Our scenario generation method is designed to explicitly capture the regional and time-slice correlation of the uncertain parameters. This is elaborated in the sections below, where we describe the scenario generation of each uncertain parameter. Due to limited access to historical data, the uncertain parameters are modelled as independent (more data would be needed to estimate correlations). Consequently, we do not capture the correlation between hydro production and wind production in Norway and Sweden with the European electricity prices. This is not unrealistic, as the energy systems in Norway and Sweden are relatively small compared to the rest of Europe, hence the electricity generation in these countries has a limited influence on the European electricity prices. Another model assumption is that the uncertain parameters are modelled as independent between long-term model periods. This implies for example that there is no dependency between the wind conditions in 2030 and wind conditions in 2035.

3.2.1. Hydro production scenarios

The basis for the hydro scenarios are seasonal availability factors from 1995 to 2014, in all model regions and for both Reservoir and ROR hydro plants. The availability data are derived by seasonal production data on a national level from 1995 to 2014 for Norway and Sweden, as illustrated in Fig. 2. First, this national production data is divided into that belonging Nord Pool model regions. For Norway, the distribution is based on regional hydro inflow series from 1995 to 2014 (NVE, 2014), and for Sweden the distribution is based on expected production of the Swedish price regions. Second, the seasonal production data is divided into production from Reservoir and ROR plants, by assuming the ROR production is proportional with the hydro inflow. Third, we derive the seasonal availability factor, for both plant types, by dividing the seasonal production with the installed capacity.

For each model period, a scenario is generated by a random sample of a historical year between 1995 and 2014. Thereafter we use the corresponding availability factors of each season for the ROR plants and the corresponding annual availability factors for the Reservoir plants as a model input in all regions. This approach is designed to ensure the correlation between model regions, seasons and hydro plant types. To confirm that the hydro scenarios are representative with regard to the statistical mean, we have controlled that the average of all scenarios over all model periods is in accordance with the historical data.

With four seasons, a scenario consists of four stochastic parameters for ROR plants and one stochastic parameter for Reservoir plants for each region and model period. To illustrate the characteristics of the hydro scenarios, we depict the maximum, minimum, median of the 21 scenarios on availability factors in NO5 for 2020 in Fig. 3. Here, for ROR hydro, the median seasonal availability is largest in summer with 0.77, smallest in winter with 0.39 and the spread of the availability factor is greatest for autumn ranging from 0.22 to 0.46. For the Reservoir hydro, the median availability factor is 0.56 and ranges from 0.48 to 0.66.

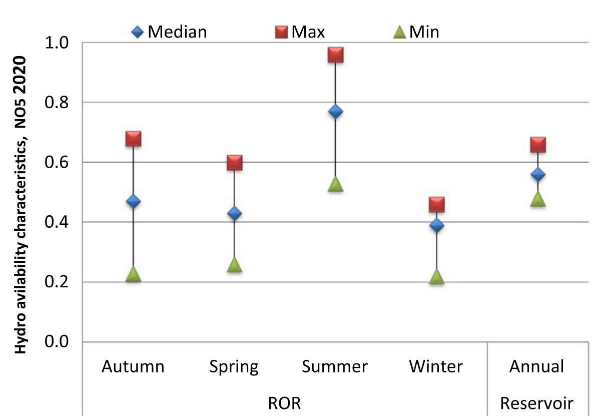


Fig. 3. Hydro scenario characteristics for NO2 2020; Minimum, Median and Maximum of seasonal and annual availability factors for ROR and Reservoir hydro.

3.2.2. Wind production scenarios

The basis for the wind scenarios is hourly availability factors, which is a measurement of the hourly wind power production over to the installed capacity, for all model regions from 2012 to 2014. First, historical availability factors are derived by dividing hourly production data by the installed capacity in each model region. Second, every second hour from the data set is selected to adjust to the time-slice structure of the model with 12 two-hour daily steps.

For each model period, the input scenarios are generated by a random sample of 21 days within each season. Thereafter, the corresponding hourly availability factors of the sampled day are used as a model input for all model regions. Finally, the scenarios are adjusted such that the expected value of all scenarios equals our assumed annual availability factor for each wind turbine type. Note that the correlation between the daily periods is taken into account since a scenario consists of chronological wind availability data, and that the regional correlation is explicitly captured as the same day is used for all regions.

With four seasons and 12 two-hour periods, a scenario consists of 48 stochastic wind parameters for each region, wind turbine type and model period. Fig. 4 illustrate the characteristics of the model input on wind availability factors, for a wind turbine with an expected annual availability factor at 0.33, for winter 2030 in SE3, by showing the 25/75 quantile, minimum, maximum and median of the daily realisations in the 21 stochastic scenarios. The figure shows that the wind availability is highly stochastic, and for this model input, the availability factor ranges from 0.01 at 16:00 to 0.89 at 16:00.

3.2.3. Electricity trade price scenarios

The basis for the electricity trade price scenarios is four hourly electricity price series in the countries with trading capacity to Norway and Sweden, for all model periods; see Section 4.2 for a further description of these price series. In each model period, a scenario is created by a random sample of a day within each season. Thereafter, every second hour of the corresponding hourly prices, in all trading regions, is used as a model input. This methodology ensures the correlation of the electricity trade price between the daily periods and European countries.

4. Model cases

This section presents the model input, and in particular the combinations of policy actions and energy price developments that we study. We analyse 16 different model cases, as four different policy actions are evaluated separately under four different assumptions on the price development on biomass, fossil fuels and electricity outside Norway and Sweden. We emphasise that the model cases and stochastic scenarios are two different types of model input. While the stochastic scenarios describe the short-term uncertainty of electricity supply, the model cases represent different long-term realisation of policy actions and energy prices.

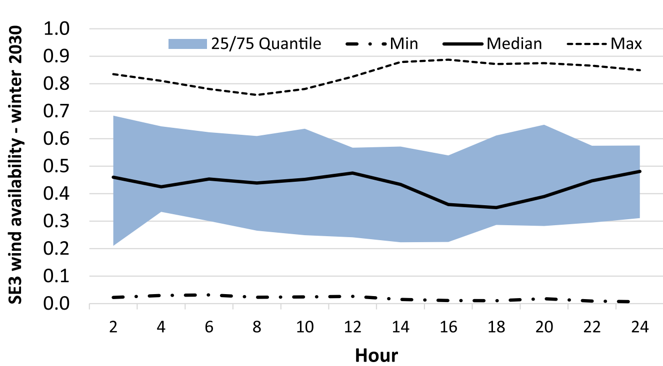


Fig. 4. Wind scenario characteristics for SE3 winter 2030; 25/75 Quantile, Minimum, Median and Maximum of daily wind availability factors.

Table 3
Overview of policy actions.

Policy choice		Description
REF	REFerence	No policy action
NNU	No NUclear	Nuclear shutdown in Sweden by 2030
HYD	HYDro	Cancelation of the restricted Norwegian hydro potential
LTD	Limited TraDe	No new export capacity to Europe

4.1. Policy actions

Table 3 summarises the policy action related to nuclear power, hydropower and transmission capacity to Europe. The first policy, named *REF*, involves no new policy action; the nuclear power production is continued, large parts of the Norwegian hydro potential are restricted and it is possible to invest in new export capacity to Europe.

The second policy assumes a gradual shutdown of nuclear power in Sweden by 2030, and is denoted *NNU*. The nuclear capacity is a model input, and for the policy actions except *NNU*, we consider the adopted shutdown of the oldest reactors in Ringhals and Oscarshamn, and assume that the remaining capacity, at 6.7 GW, is maintained towards 2050. In the nuclear shutdown policy, *NNU*, we assume a gradual decommissioning of all reactors by 2030 with a capacity drop to 5.5 GW in 2020 and 3.4 GW by 2025.

The third policy, denoted *HYD,* involves an expansion of the Norwegian hydropower potential. This policy choice assumes a cancelation on the restricted hydro potential, increasing the Norwegian hydropower potential from 31 TWh to 80 TWh. We assume the restricted potential has the same characteristic as the existing plant stock in regards to costs, regional location and share of flexible plants.

The fourth policy, *LTD*, implies limited electricity trade and supposes a ban on new export capacity to the European electricity market out of Norway and Sweden. This policy does not allow for any new electricity transmission capacity out of the region, and prohibits the capacity expansion projects, “NSN Link” between Norway and the United Kingdom and”NordLink” between Norway and Germany.

4.2. Energy price assumptions

The four price assumptions, *P1 – P4*, have different assumptions with regard to long-term energy prices and electricity price variability, and are summarised in Table 4. This is done in order to capture a range of possible realisations of the future energy market as future energy prices are highly uncertain as it inter alia depends on demand, market design, degree of market power, support schemes and future development of resources and technology. In addition, more intermittent production can give higher electricity price variability.

The first two assumptions, *P1* and *P2*, are based on an increase in

Table 4
Summary of the energy price assumptions.

Price assumption	Description
P1	Increased annual energy prices towards 2050 2014 electricity price variation
P2	Increased annual energy prices towards 2050 Higher electricity price variation
P3	Constant annual energy prices towards 2050 2014 electricity price variation
P4	Constant annual energy prices towards 2050 Higher variance in electricity prices

Table 5
Overview of energy price assumptions in 2015, 2030, 2040 and 2050 for P1 and P2.

		2015	2030	2040	2050
Fossil fuels					
Coal	EUR/ MWh	8	13	14	14
Natural gas	EUR/ MWh	22	35	36	36
Oil	EUR/ MWh	37	69	72	72
Biomass					
Pellets	EUR/ MWh	28 – 43	31 – 46	31 – 47	31 – 47
Straw	EUR/ MWh	22	26	27	27
Chips	EUR/ MWh	21 – 32	24 – 37	25 – 38	25 – 38
Biogas	EUR/ MWh	30 – 45	31 – 47	33 – 49	33 – 49
Electricity					
Denmark West (DK1)	EUR/ MWh	32	63	64	64
Denmark East (DK2)	EUR/ MWh	34	63	64	64
Finland (FI)	EUR/ MWh	31	57	58	58
Germany(DE)	EUR/ MWh	35	62	64	64
Lithuania (LI)	EUR/ MWh	35	62	64	64
Poland (PO)	EUR/ MWh	35	62	64	64
The Netherlands (NL)	EUR/ MWh	45	65	65	65
United Kingdom (UK)	EUR/ MWh	68	75	72	72

the long-term energy prices in accordance with (Energinetdk, 2015) that is indicated in Table 5. These energy prices are based on forward prices and energy prices from the New Policy Scenario in the World Energy Outlook. The last assumptions, *P3* and *P4*, assume constant energy prices towards 2050 where the energy prices of 2015 in Table 5 are used as a model input for all future model periods.

Further, the price assumptions *P1* and *P3* use electricity price variability according to the historical variations observed in 2014. The variations are based on hourly electricity prices of 2014 in Denmark, Germany, the Netherlands, Finland, Lithuania, Poland and the United Kingdom. As the 2014 prices reflect the current share of intermittent electricity supply in Europe, we also include price assumptions with higher electricity price variations. The other two price assumptions, *P2* and *P4,* assume a gradual increase in the price variability towards 2030 that is designed by taking the square of the hourly electricity prices in 2014 adjusted to the annual price. To illustrate the model input on electricity prices, the 25/75 quantiles, median, minimum and maximum value of the daily German price realisations in summer 2030 are plotted in Fig. 5 for all energy price assumptions. Here, the electricity price varies with the price assumption, time of the day and stochastic scenario. For example at 10:00, the electricity prices range from 43 EUR/ MWh to 116 EUR/ MWh for *P2* and from 30 EUR/ MWh to 53 EUR/ MWh for *P3* among the stochastic scenarios.

5. Results and discussion

This section presents the main results with focus on the impact of policy actions, the impact of the energy price assumptions and the value of a stochastic modelling approach. If not specified, we report the expected value of the operational model decisions, an average of the realisation of the 21 stochastic scenarios.

5.1. Impact of policy actions

The key impacts of the analysed policy actions are the same for the four price assumptions. For example, compared to the no policy case, a nuclear shutdown increases the investments in renewable electricity generation in Norway and Sweden, and this effect is observed for all the various energy price assumptions. However, the quantity of the optimal investments varies with the model input on future energy prices. For example in 2030, a nuclear shutdown increases the wind capacity by 4.0 GW for price assumption *P1*, and by 5.3 GW for price assumption *P2*. Further in this section, we present results for all policy actions with *P1* in 2030. Appendix A includes figures depicting the corresponding results for all model cases in 2030 and 2050.

The expected net electricity export from Norway and Sweden is plotted against the expected electricity generation in Fig. 6, where the corresponding electricity generation capacity, split by type, is depicted in Fig. 7. Compared to the reference policy (*REF*), the alternatives nuclear shutdown (*NNU*), and no new electricity export (*LTD*), result in lower export and generation whereas an increase in hydro potential (*HYD*), with permission to build more hydropower, gives higher export and production. The policy actions primarily affect the competition between electricity and biomass supply whereas the fossil fuel consumption is less affected. This is because these policies mostly have an impact on the electricity and building sectors, where the fossil fuel consumption is limited. Fig. 8 illustrates how the expected biomass and electricity consumption in Norway and Sweden varies with the policy actions. Here, the consumption includes the utilisation of biomass and electricity in all parts of the energy sector, including consumption for industry, electricity generation, transport, district heating production and building heat. Compared to *REF*, *NNU* results in lower electricity consumption and higher biomass consumption whereas the other strategies, *HYD* and *LTD*, have higher electricity and lower biomass consumption. Note that the difference between *REF* and *NNU* is significantly larger for the other energy price assumptions (See Appendix A).

A nuclear shutdown in Sweden increases the electricity price level in both Norway and Sweden, as the nuclear electricity supply is partly replaced with more costly production technologies and substituted by other energy carriers. The greatest price increase is in the Swedish Nord pool price area SE3, where the nuclear reactors are located, with an annual electricity price increase of 21%. The price impact is lower for the other price areas, and is for example 3% in the Norwegian price area with the highest population, NO1. A consequence of the increased price level is higher investments in wind capacity and a decrease in domestic electricity consumption. Jointly, this results in a decreased total electricity generation and a lower electricity export. Compared to *REF*, *NNU* lowers the electricity generation by 26 TWh, from 311 TWh to 286 TWh, has 23 TWh lower net electricity export, 3 TWh lower electricity consumption and 6.8 GW more wind power capacity. A large part, 3.5 GW, of the additional wind power capacity is located in SE3, whereas the remaining wind investments are spread throughout other price areas in Norway and Sweden.

As opposed to the nuclear shutdown policy, an expansion of the Norwegian hydro potential lowers the electricity price level in Norway and Sweden and increases the net electricity export. The price impact is larger in Norway than in Sweden, with for example an annual electricity price decrease of 26% in NO1 and 4% in SE3. The lower prices are caused by the new potential that gives additional investments in remunerative Reservoir hydro plants. This lowers the investments in other types of electricity generation capacity and increases the electricity consumption. The increased electricity consumption is both caused by a substitution of technologies with lower efficiencies, from heat pumps to direct electric heating, as well as fuel substitution from biomass to electricity to meet the heat demand in buildings. Compared to *REF, HYD* has 20 TWh higher electricity generation, 7 TWh higher net electricity export, 11 TWh higher electricity consumption, 0.6 GW less CHP, 1.2 GW less wind, 0.8 GW less ROR hydro and 7.3 GW more Reservoir hydro. The Norwegian price area with transmission capacity to Europe, NO2, has the majority of the additional Reservoir hydro investments with 3.4 GW. The reduced CHP capacity decreases the share of district heat supplied by CHP plants, from 82% for *REF* to 76% for *HYD*.

The model invests in new electricity export capacity to Germany and the United Kingdom from Norway when it is an option in a model case. Consequently, restricting these expansion projects in *LTD*, increases the energy system cost and affects the model decisions. A lower export capacity to Europe limits the utilisation of electricity

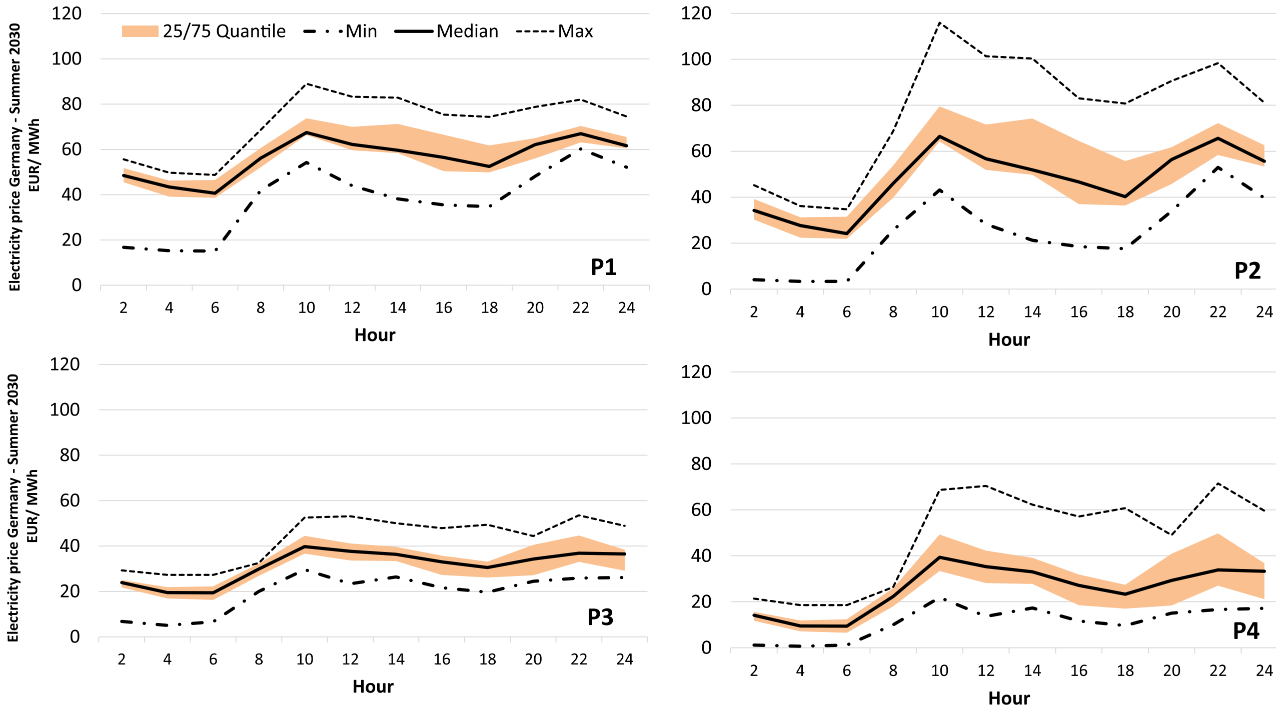


Fig. 5. Electricity price scenario characteristics for Germany summer 2030; 25/75 Quantile, Minimum, Median and Maximum daily price realisations for all price assumptions.

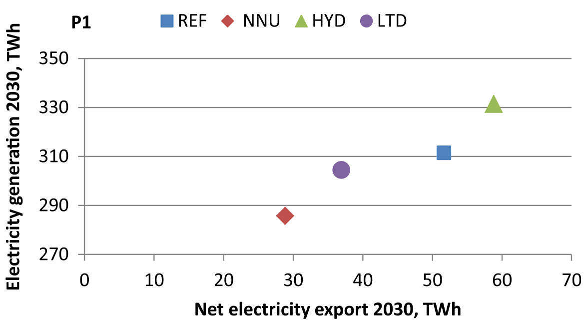


Fig. 6. Expected net electricity export versus expected electricity generation in 2030 for all policy actions and energy price assumption P1.

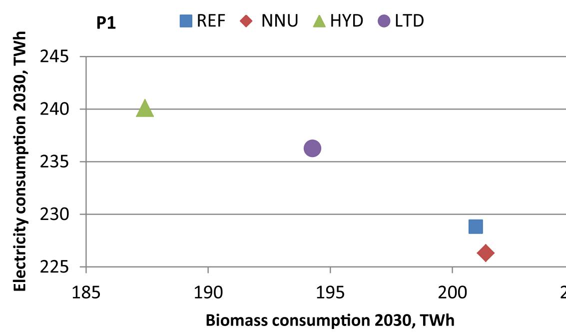
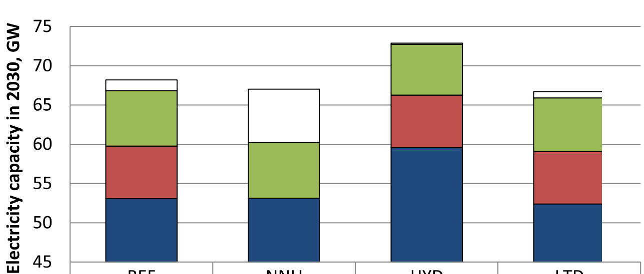


Fig. 8. Expected biomass consumption versus expected electricity consumption in 2030 for all policy actions and energy price assumption P1.

generation and reduces the back-up opportunities for non-flexible electricity generation. This results in a lower annual price level and higher variability of the hourly electricity prices in both Norway and Sweden. For example, the annual price is decreased by 12% in N01 and 3% in SE3 with a corresponding increase in the standard deviation of the hourly price at 84% and 47% respectively. Further, this policy reduces the investments in all types of electricity generation capacity besides the flexible hydro plants, and increases the domestic electricity consumption. Similar to *HYD*, the increased electricity consumption is caused by a substitution of technologies with lower efficiencies and by fuel substitution from biomass to electricity. Compared to *REF*, *LTD* has 7 TWh lower electricity generation, 7 TWh higher electricity consumption, 15 TWh lower net electricity export, 0.2 GW less CHP, 0.6 GW less wind and 0.7 GW less ROR hydro.



	REF	NNU	HYD	LTD
Wind	1.4	6.8	0.2	0.8
CHP	7.1	7.1	6.5	6.8
Nuclear	6.7	0.0	6.7	6.7
Hydro	53.1	53.1	59.6	52.4

Fig. 7. Electricity capacity in 2030 for all policy actions and energy price assumption P1.

5.2. Impact of energy price assumptions

The main impact of the different price assumptions is identical for all policy actions. For example, the biomass consumption is highest with price assumption, *P1*, for all policy actions. If not otherwise specified, this section discusses the results in 2030 for the various energy price assumptions and the reference policy action, *REF*. Nevertheless, the core conclusions presented in this section, are valid for all four policy actions. Appendix B gives figures for the corresponding results for all model cases in 2030 and 2050.

For Norway and Sweden, it is beneficial with high variability in the European electricity market and no future increase in the energy prices. Larger variations in the European electricity prices increases the value of the flexible hydro reservoirs since the hydro flexibility enables the possibility to export when the electricity prices are high, and import

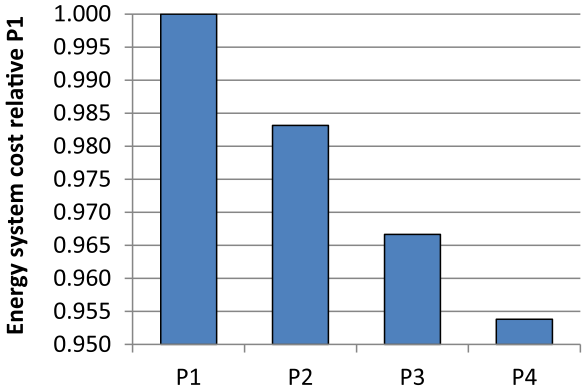


Fig. 9. Energy system cost, relative energy price assumption P1, for all energy price assumptions and the reference policy, REF.

when the electricity prices are low. This indicates that it is valuable for Norway and Sweden to take an active part in the future European electricity market design as this ensures adequate utilisation of the flexible hydro reservoirs. This is confirmed by the energy system cost for the four price assumptions relative to *P1* that is shown in Fig. 9. Here the energy system cost represents the minimum energy system cost, accumulated for the time horizon from 2010 to 2050, to meet the specified energy demand in Norway and Sweden. With increasing energy prices, a higher electricity price variation, reduces the energy system cost by EUR 18 billion when comparing the system cost of *P1* and the system cost of *P2*. Similar, for constant energy prices, the energy system cost is decreased by EUR 14 billion when comparing *P3* with *P4*. Compared to increasing energy prices, constant energy prices result in lower fuel prices, less income related to electricity export and less costs related to electricity import. Together, constant energy prices are more cost-optimal for the energy systems in Norway and Sweden, and the difference in energy system cost is EUR 35 billion between *P3* and *P1*, and EUR 31 billion between *P4* and *P2*.

The European energy market is a core driver for the optimal investment in electricity capacity in Norway and Sweden. This is illustrated in Fig. 10, where the electricity generation capacity, split by type, for all energy price assumptions is depicted. Note that the y-axis starts at 45 GW to better illustrate the differences between the non-hydro technologies. Here, the investments are higher with increasing energy prices compared to constant prices. For example, the total electricity capacity is 68.2 GW for *P1* and 62.0 GW for *P3*. Higher electricity prices favour development of new plants and the export of electricity, while lower electricity prices favour the import of electricity. In addition, the variability of the European electricity prices makes an impact on optimal investments, particularity in wind power. The wind capacity ranges from 1.4 GW for *P1* to 0.1 GW for *P4*. Consequently,

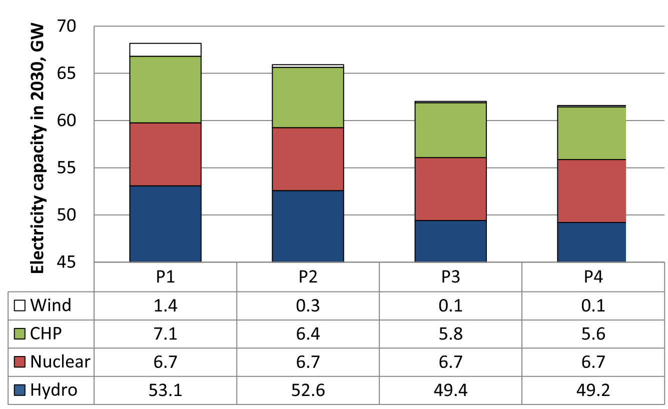


Fig. 10. Electricity capacity for all energy price assumptions in 2030 for the reference policy, REF.

price-independent support schemes for new renewable capacity can give sub-optimal investments.

The electricity generation in Norway and Sweden remains dominated by hydropower for all price assumptions, and it is optimal to expand a larger share of the Reservoir and ROR hydro potential. This is conditioned by our assumption that the existing hydro capacity remains available throughout the model horizon. New investments in ROR capacity depend more on the energy price development than the Reservoir capacity. The new built Reservoir capacity ranges from 1.5 GW for *P4* to 2.1 GW for *P1*, corresponding to 64% and 91% of the new capacity potential/ the maximum invested capacity respectively. Similarly, the investments in ROR capacity range from 1.4 GW for *P4* to 4.7 GW for *P1*, corresponding to 26% and 86% of the new potential respectively. Along with hydro, CHP has a considerably share of the electricity generation for all price assumptions. The CHP capacity ranges from 5.6 GW with *P4* to 7.1 GW with *P1*, where the fuel consumption is primarily biomass and waste. Here, the share of heat supplied by CHP plants, of the district heat demand, ranges from 82% with *P1* to 65% with *P4*.

In addition to influencing the investments in new electricity capacity, the energy price assumptions affect the domestic use of electricity and consequently also the electricity trade to Europe. Fig. 11 depicts the net electricity export from Norway and Sweden, with indication of the expected electricity trade and the range for the possible realisations. The expected value is the average of the net export over all the stochastic short-term scenario outcomes, and the minimum and maximum values represent the value of the extreme scenarios. The spread of the net export is significant and is primarily caused by annual variations in the hydro production. It is clear that the export depends on the price assumptions, where the expected net electricity export ranges from 5 TWh in *P4* to 52 TWh in *P1*. For *P4*, the net electricity trade ranges from 35 TWh import to 41 TWh export over the outcomes of the short-term scenarios. Further, the results indicate that the net export from Norway and Sweden is higher with increased energy prices, compared to constant energy prices, and decreases with higher electricity price variability.

5.3. Impact of using a stochastic model

This section compares investment decisions obtained from stochastic and deterministic models, and presents the value of applying a stochastic approach. The two model types are similar, except for the representation of the stochastic parameters, where the average value of the uncertain parameters is used as a model input in the deterministic approach. This implies that the stochastic model, with a more realistic representation of the energy sector, has higher computational complexity than its deterministic equivalent. As the modelling approach primarily affects the electricity and building sectors, we focus on these sectors below.

In the electricity sector, the deterministic model has higher investments in intermittent renewable electricity generation for all model cases in 2030 and 2050, while there is no similar general trend for the

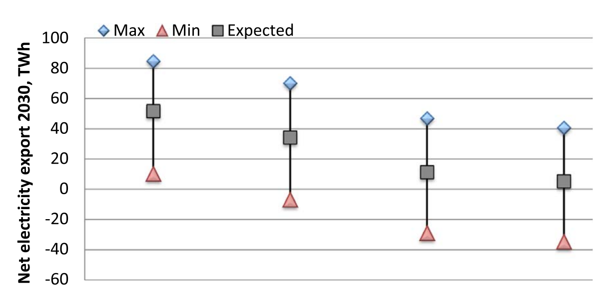


Fig. 11. Net electricity export for all energy price assumptions in 2030 for the reference policy, REF, indicating maximum, minimum and expected value.

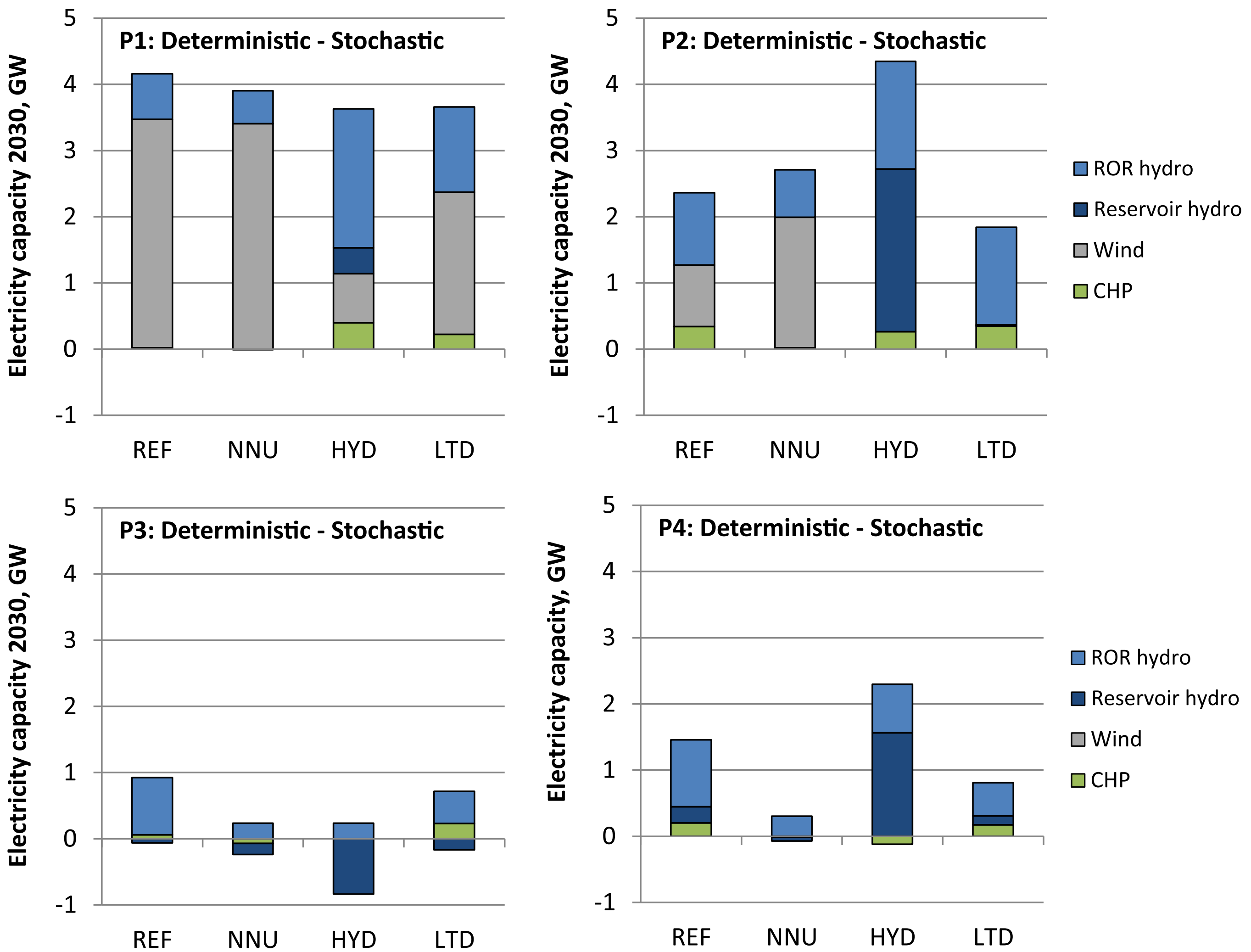


Fig. 12. Difference in electricity capacity between a deterministic and stochastic approach in 2030 for all model cases.

flexible production technologies. This is caused by stochastic modelling, unlike the deterministic approach, explicitly models a range of operational situations which can occur. This includes for example periods with poor wind conditions, low hydro inflow and high European electricity prices, and periods with excess power supply in Norway and Sweden and limited export opportunities. Fig. 12 depicts the difference in investments in electricity generation capacity between the deterministic and stochastic approaches in 2030 for all model cases, split by capacity type. The corresponding results for 2050 are illustrated in Appendix C. Here, the difference in electricity generation capacity ranges from −0.6 GW for the increased hydro potential policy, *HYD*, and energy price assumption *P3* to 4.3 GW for *HYD* and energy price assumption *P2*. Compared to the stochastic approach, the deterministic approach has 0.8 GW lower Reservoir hydro capacity and 0.2 GW higher ROR capacity for *HYD* and *P3*, whereas for *HYD* and *P2,* the CHP, Reservoir and ROR capacity is 0.3, 2.5 and 1.6 GW higher for the deterministic model respectively. Although, the difference in electricity generation capacity between the two approaches is relative small compared to the total installed capacity, it has a significant impact on the model results for some model cases. For example for energy price assumption *P1* in 2030, the deterministic results have 253%, 50%, 483% and 268% more wind capacity compared to a stochastic approach for the reference policy (*REF*), the nuclear shut down policy (*NNU*), *HYD* and for the limited trade policy (*LTD)* respectively.

The electricity generation capacity influences the cost-optimal electricity trade capacity from Norway and Sweden. As the deterministic approach models an average value of the uncertain parameters, it value the flexibility related to electricity trade capacity differently than the stochastic approach. While the stochastic model expands the export capacity for all model cases, there are no investments in new export capacity to Germany in the deterministic model for *REF*, *NNU* and *HYD* with energy price assumption *P3*.

In the building sector, the deterministic approach invests in less heat capacity, in particular low-efficient electricity-based heating, compared to a stochastic approach. This can be explained by the fact that the stochastic approach, with scenario dependent electricity prices, invests in additional low-cost electricity-based heating, to meet the heat demand in periods with low electricity prices. Furthermore, the influence of the modelling approach on investments in heat pumps, gas and biomass technologies depend on policy actions, price assumption and model period. This is illustrated in Fig. 13 which depicts the difference in heat capacity in the building sector between the deterministic and stochastic approaches in 2030, split by technology, for all model cases. The corresponding results for 2050 are illustrated in Appendix C. Note that the DH capacity is excluded as it is exogenously given. Here, the technology group named *Electricity* includes both electric boilers and direct electric heating. In 2030, the total capacity difference ranges from 0.0 GW for *NNU* and *P3* to −2.5 GW for *NNU* and *P2*. Although the total capacity is indifferent for *NNU* and *P3,* the deterministic approach has 0.4 GW lower investments in *Electricity* capacity and 0.1 GW and 0.3 GW higher investments in heat pump and

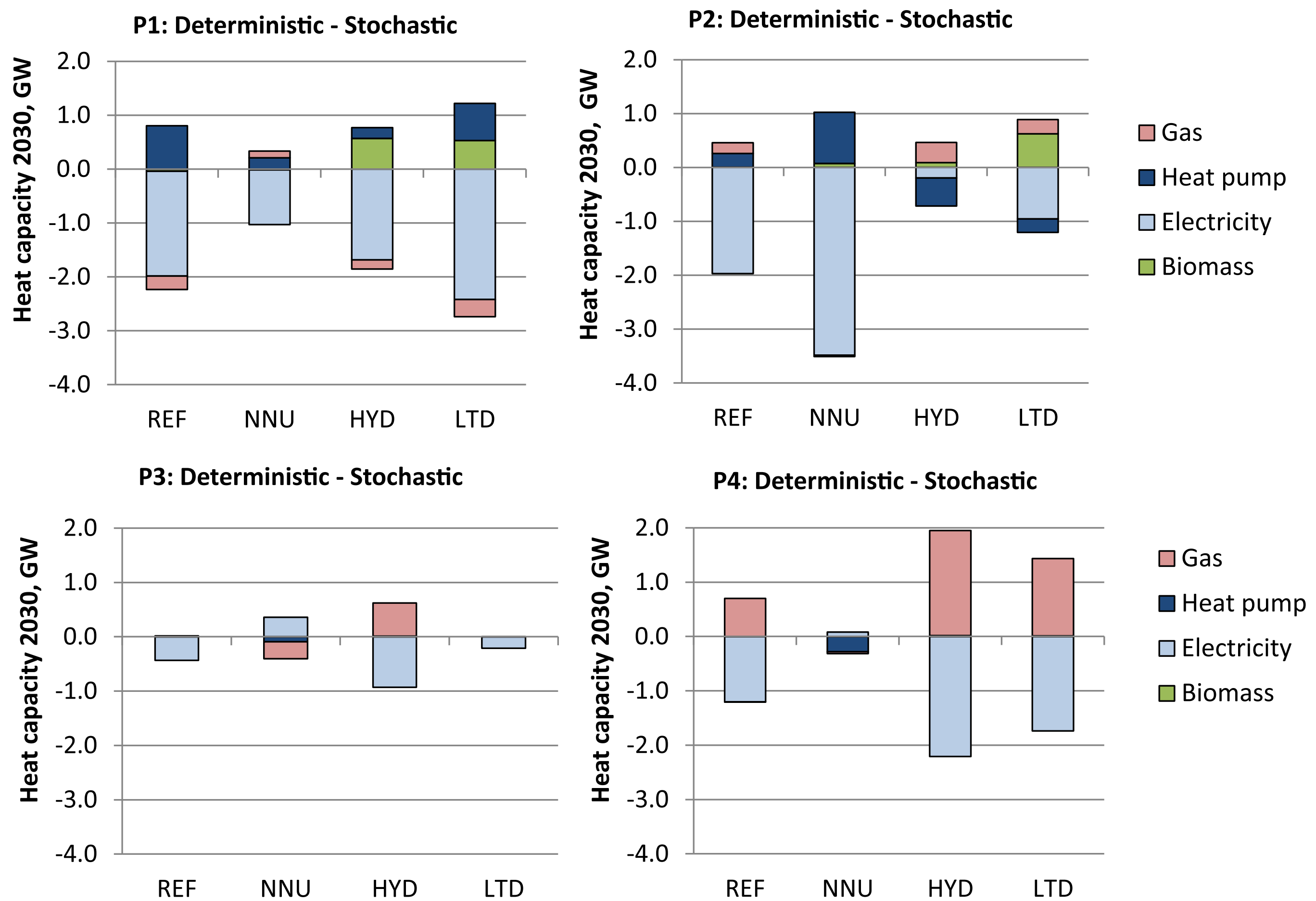


Fig. 13. Difference in heat capacity between a deterministic and stochastic approach in 2030 for all model cases.

gas capacity respectively. Similarly, the *Electricity* capacity is 3.5 GW lower and the heat pump and biomass capacity is 0.9 GW and 0.1 GW higher for respectively for *NNU* and *P2*.

The Value of the Stochastic Solution (VSS) (Higle, 2005) is a tool to quantify the benefit of using a more complex stochastic model compared to a deterministic approach. The first step to calculate VSS is to find the investment decisions from the deterministic model. Second, the stochastic model is solved with the fixed investments from the deterministic model. Finally, the VSS is the difference in optimal objective function value between this stochastic model, with fixed deterministic investment decisions, and the objective function of the original stochastic model. The VSS is presented for all model cases in Table 6. Here, the VSS ranges from EUR 0.1 billion for *LTD* and *P3* to EUR 3.0 billion for *HYD* and *P1*.

6. Conclusions and policy implications

We use a TIMES model with a stochastic representation of the short-term uncertainty of electricity supply to study the effects of various policy actions on the energy system in Norway and Sweden from a social welfare perspective. Our stochastic approach provides cost-optimal investments in the energy system that considers a set of operational situations and explicitly value flexibility. We observe that a deterministic approach gives more wind power capacity, less interconnection capacity to Europe and lower investments in low-efficient electric heating in buildings compared to a stochastic approach. Below, we present the core insights obtained from our stochastic model.

Table 6
The Value of Stochastic Solution for all model cases, billion EUR.

Model case	P1	P2	P3	P4
REF	1.3	1.9	0.2	1.1
NNU	1.2	1.8	0.4	1.1
HYD	3.0	2.8	0.6	1.4
LTD	2.0	1.9	0.1	0.7

Implementation of energy and environmental policy actions influence cost-optimal investments and affect the flexibility of the electricity supply in Norway and Sweden. A nuclear shut-down in Sweden causes a larger share of intermittent generation in the electricity sector, a cancelation of the restricted hydropower in Norway gives additional investments in flexible hydro plants, and no new export capacity to Europe restricts the utilisation and back-up opportunities of intermittent electricity generation. Consequently, the future role of the flexible hydro reservoirs in Norway and Sweden, to integrate intermittent renewables in northern Europe, depends on the adopted policy measures.

In addition to policy actions, the European energy market is a core driver for optimal investment in electricity generation capacity in Norway and Sweden. A higher European electricity price level increases the development of new capacity and electricity export, whereas lower electricity prices give more electricity import. Also, higher fluctuations in the European electricity prices reduce investments in electricity generation capacity, due to inflexibility in the energy system. High fluctuations in the European electricity price, is however beneficial for Norway and Sweden. This is because the hydro flexibility enables the possibility to export when the electricity prices are high, and import when the electricity prices are low. The development of the energy system also affects the cost-optimal electricity trade from Norway and Sweden to other European countries. A key finding is that it is profitable to expand the export capacity to Europe for all analysed policy actions and energy price assumptions.

Based on the gained insights, we suggest that policy actions in Norway and Sweden, on nuclear power, hydro resources and electricity trade capacity should be evaluated in the light of their effects on the interaction with the European electricity market. In order to do so, an underlying analysis of the energy system should take into account the short-term uncertainty of renewable electricity generation.

Acknowledgements

The authors are grateful to the Research Council of Norway for funding this work as a part of the project “The future Norwegian energy system in a North-European context” (Grant number: 207067; https://www.forskningsradet.no/prosjektbanken/#!/project/207067/en). In addition, the authors acknowledge Anna Krook Riekkola at the Luleå University of Technology (LTU) for useful input on this paper and on the Swedish energy system.

Appendix A

See Figs A.1–A.16.

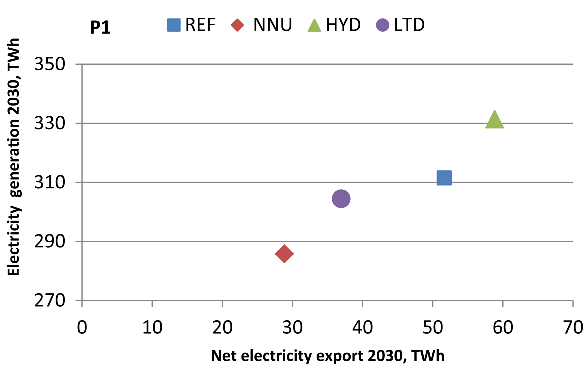


Fig. A.1. Expected net electricity export versus expected electricity generation in 2030 for all policy actions and energy price assumption P1.

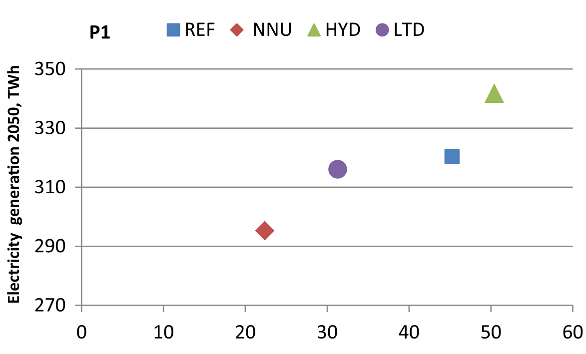


Fig. A.2. Expected net electricity export versus expected electricity generation in 2050 for all policy actions and energy price assumption P1.

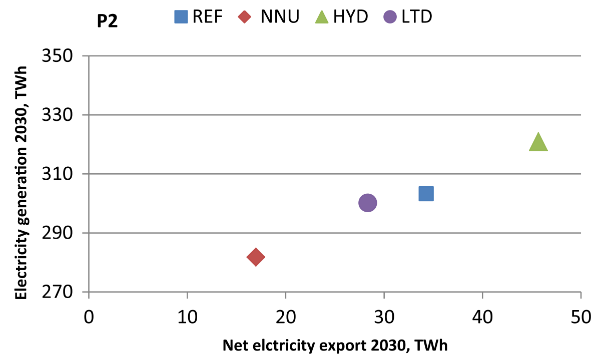


Fig. A.3. Expected net electricity export versus expected electricity generation in 2030 for all policy actions and energy price assumption P2.

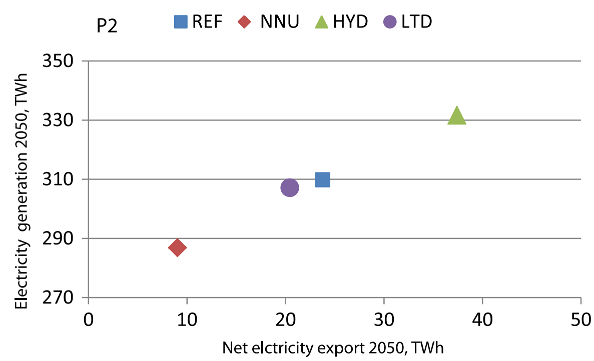


Fig. A.4. Expected net electricity export versus expected electricity generation in 2050 for all policy actions and energy price assumption P2.

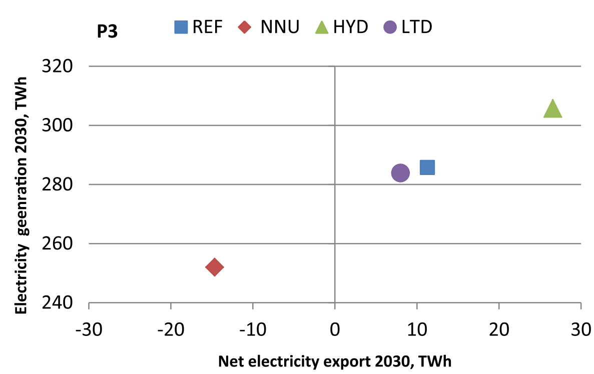


Fig. A.5. Expected net electricity export versus expected electricity generation in 2030 for all policy actions and energy price assumption P3.

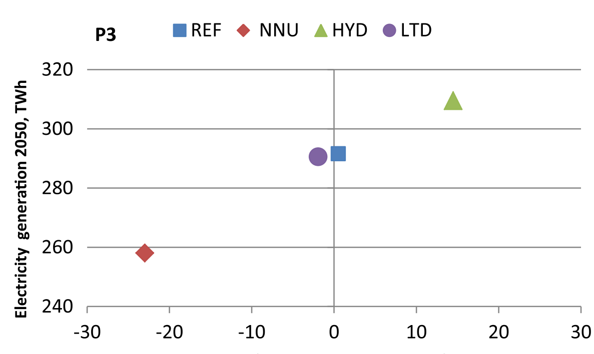


Fig. A.6. Expected net electricity export versus expected electricity generation in 2050 for all policy actions and energy price assumption P3.

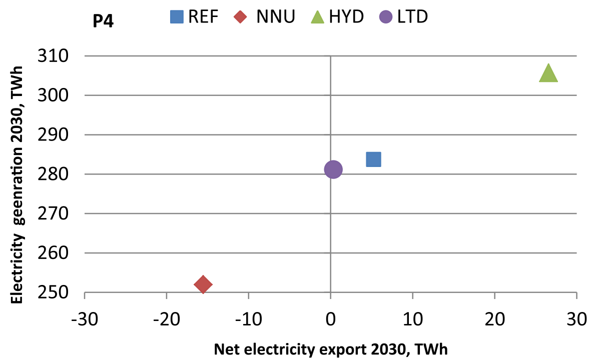


Fig. A.7. Expected net electricity export versus expected electricity generation in 2030 for all policy actions and energy price assumption P4.

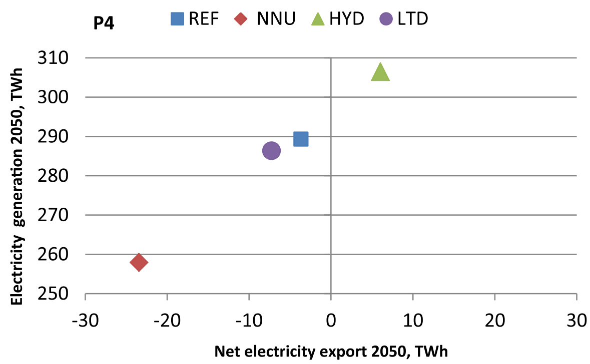


Fig. A.8. Expected net electricity export versus expected electricity generation in 2050 for all policy actions and energy price assumption P4.

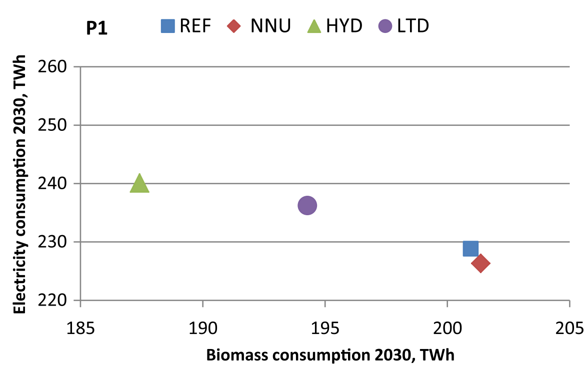


Fig. A.9. Expected biomass consumption versus expected electricity consumption in 2030 for all policy actions and energy price assumption P1.

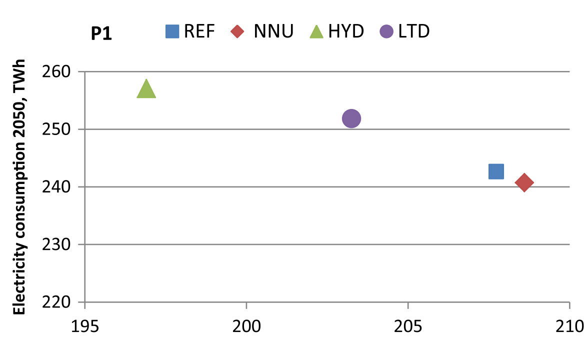


Fig. A.10. Expected biomass consumption versus expected electricity consumption in 2050 for all policy actions and energy price assumption P1.

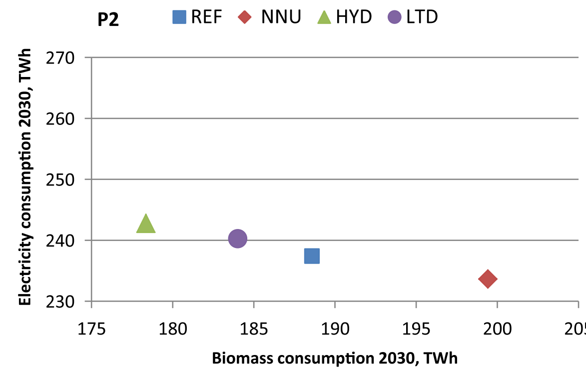


Fig. A.11. Expected biomass consumption versus expected electricity consumption in 2030 for all policy actions and energy price assumption P2.

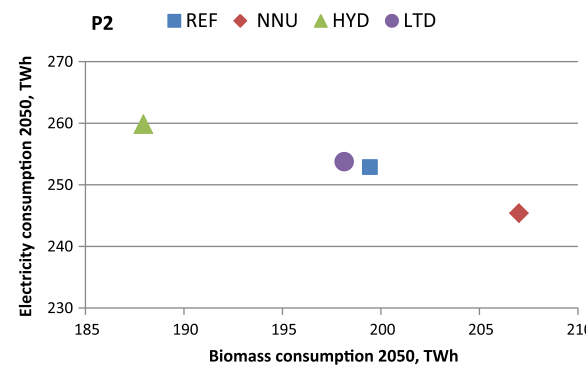


Fig. A.12. Expected biomass consumption versus expected electricity consumption in 2050 for all policy actions and energy price assumption P2.

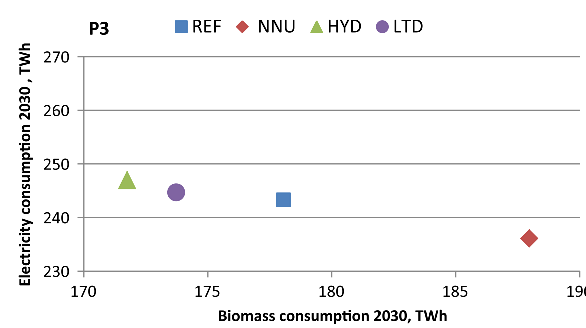


Fig. A.13. Expected biomass consumption versus expected electricity consumption in 2030 for all policy actions and energy price assumption P3.

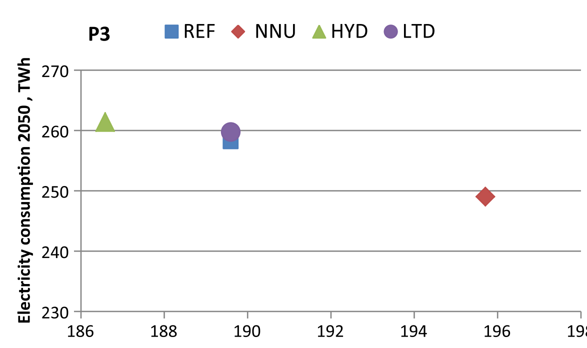


Fig. A.14. Expected biomass consumption versus expected electricity consumption in 2050 for all policy actions and energy price assumption P3.

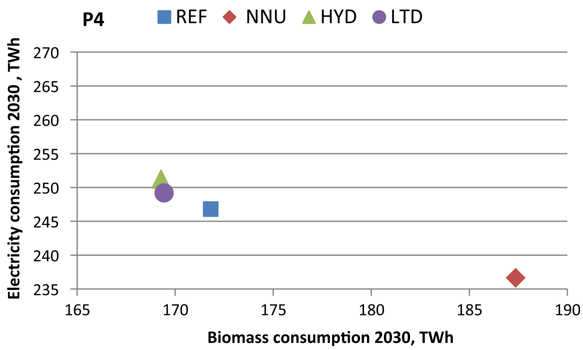


Fig. A.15. Expected biomass consumption versus expected electricity consumption in 2030 for all policy actions and energy price assumption P4.

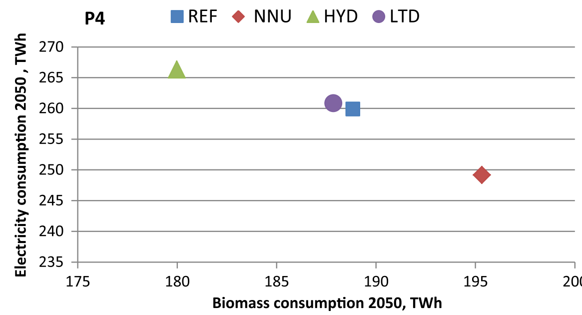


Fig. A.16. Expected biomass consumption versus expected electricity consumption in 2050 for all policy actions and energy price assumption P4.

Appendix B

See Figs B.1–B.3.

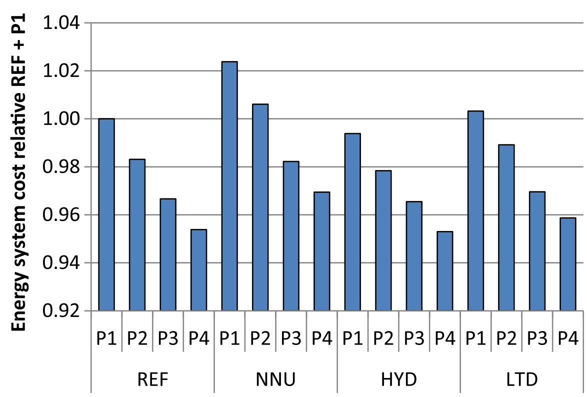


Fig. B.1. Energy system cost, relative energy price assumption P1 and REF, for all energy price assumptions and policy actions.

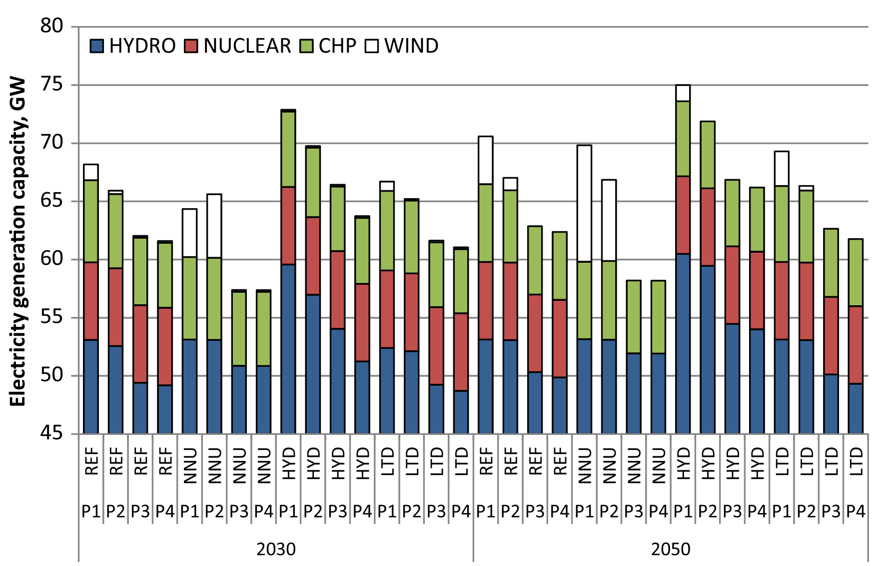


Fig. B.2. Electricity capacity for all energy price assumptions and policy actions in 2030 and 2050.

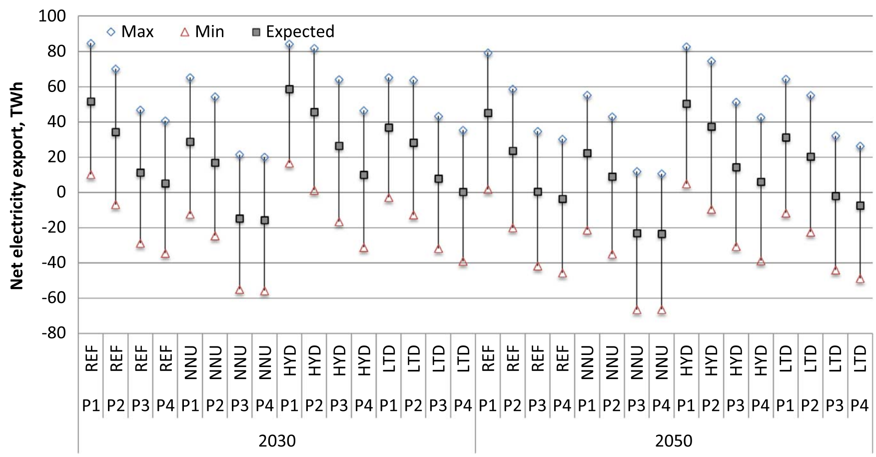


Fig. B.3. Net electricity export for all energy price assumptions and policy actions in 2030 and 2050, indicating maximum, minimum and expected value.

Appendix C

See Figs C.1 and C.2.

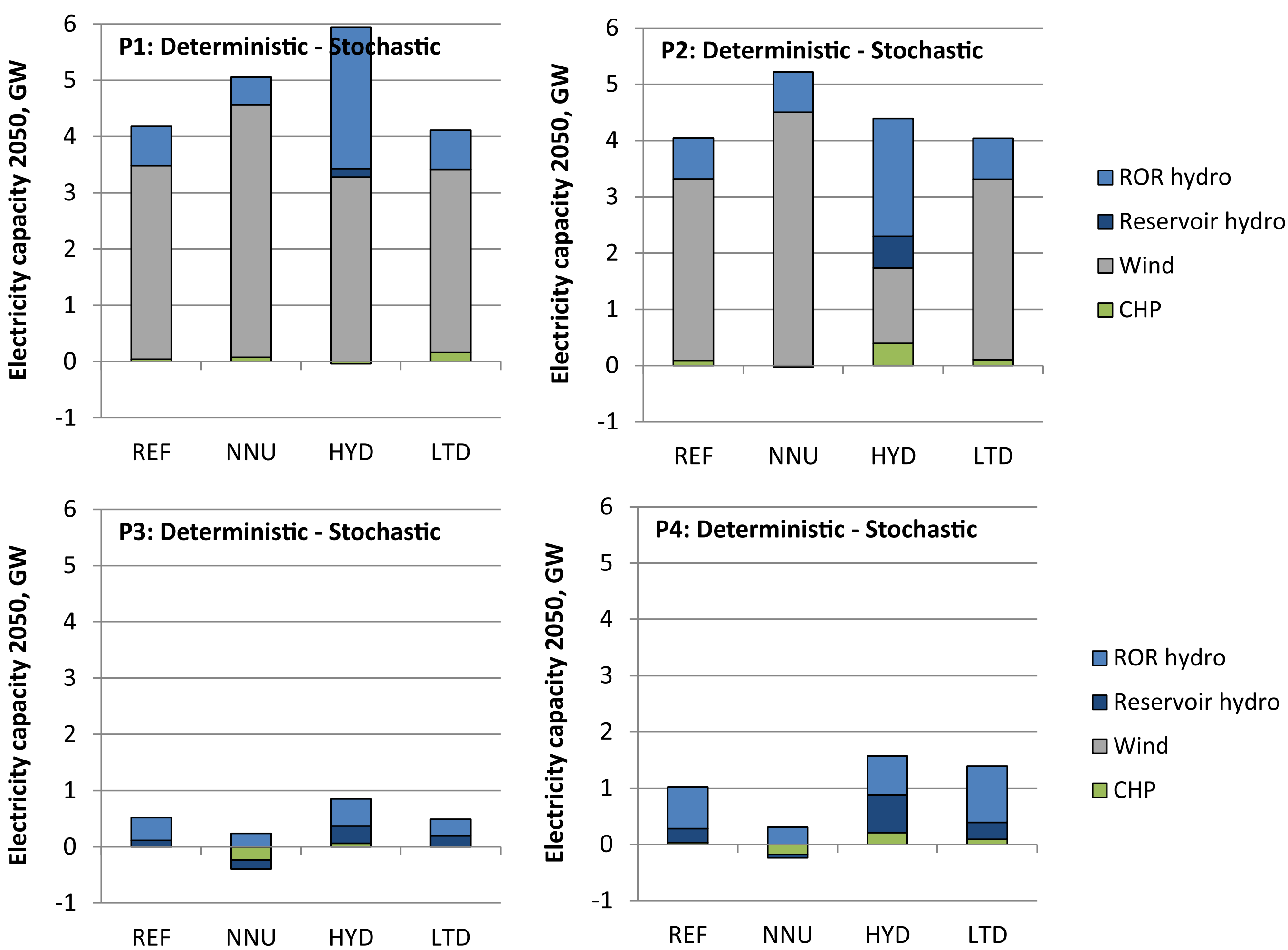


Fig. C.1. Difference in electricity capacity between a deterministic and stochastic approach in 2050 for all model cases.

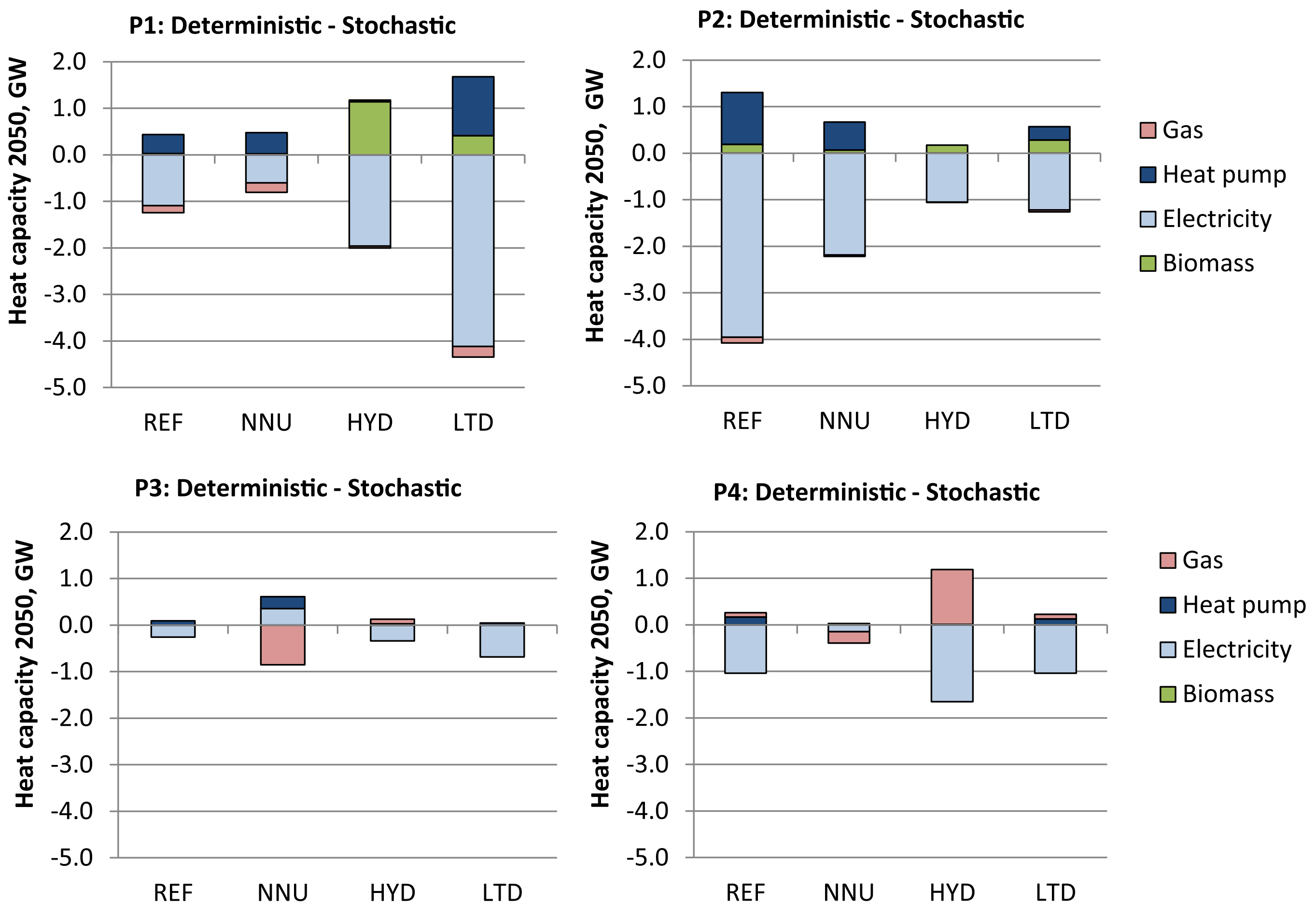


Fig. C.2. Difference in heat capacity between a deterministic and stochastic approach in 2050 for all model cases.

References

Bhattacharyya, S.C., Timilsina, G.R., 2010. A review of energy system models. Int. J. Energy Sect. Manag. 4, 494–518.

Connolly, D., Lund, H., Mathiesen, B.V., Leahy, M., 2010. A review of computer tools for analysing the integration of renewable energy into various energy systems. Appl. Energy 87, 1059–1082.

Daly, H.E., Ramea, K., Chiodi, A., Yeh, S., Gargiulo, M., Gallachóir, B.Ó., 2014. Incorporating travel behaviour and travel time into TIMES energy system models. Appl. Energy 135, 429–439.

Deane, J.P., Chiodi, A., Gargiulo, M., Gallachóir, B.P., 2012. Soft-linking of a power systems model to an energy systems model. Energy 42, 303–312.

Després, J., Hadjsaid, N., Criqui, P., Noirot, I., 2015. Modelling the impacts of variable renewable sources on the power sector: reconsidering the typology of energy modelling tools. Energy 80, 486–495.

Doorman, G.L., Frøystad, D.M., 2013. The economic impacts of a submarine HVDC interconnection between Norway and Great Britain. Energy Policy 60, 334–344.

Enerdata, 2016. POLES : Prospective Outlook on Long-term Energy Systems, http://www.enerdata.net/enerdatauk/solutions/energy-models/poles-model.php.

Energinet.dk, 2015. Energinet.dk's analyseforudsætninger 2015–2035, http://energinet.dk/SiteCollectionDocuments/Danske%20dokumenter/El/15-00248-7%20Energinet.dk%27s%20analyseforudsætninger%202015-2035%20-%20ekstern%20version.docx%202860511_2_1.pdf.

Energy Exemplar, 2016. PLEXOS, ⟨http://energyexemplar.com/software/plexos-desktop-edition/⟩.

Eurostat, 2015. Eurostat Statistics. European Union, ⟨http://ec.europa.eu/eurostat/web/energy/data/database⟩.

Fortum, 2015. OKG AB's Extraordinary shareholders' meeting decides to close Oskarshamn nuclear units 1 and 2 co-owned by Fortum in Sweden, ⟨http://www.fortum.com/en/mediaroom/pages/okg-abs-extraordinary-shareholders-meeting-decides-to-close-oskarshamn-nuclear-units-1-and-2-co-owned-by-fortum-in.aspx⟩.

Higle, L.J., 2005. Stochastic Programming: Optimization When Uncertainty Matters, Tutorials in Operational Research. INFORMS, New Orleans, p. 24.

Howells, M., Rogner, H., Strachan, N., Heaps, C., Huntington, H., Kypreos, S., Hughes, A., Silveira, S., DeCarolis, J., Bazillian, M., Roehrl, A., 2011. OSeMOSYS: the open source energy modeling system: an introduction to its ethos, structure and development. Energy Policy 39, 5850–5870.

IEA, 2013. Nordic Energy Technology Perspectives. Nordic Energy Research, Paris, France.

IEA, 2016a. Energy Technology Perspectives 2016 - Towards Sustainable Urban Energy Systems. OECD Publishing, International Energy Agency.

IEA, 2016b. Nordic Energy Technology Perspectives. Nordic Energy Research, Paris, France.

IIASA, 2012. MESSAGE. International Institute for Applied Systems Analysis, http://www.iiasa.ac.at/web/home/research/researchPrograms/Energy/MESSAGE.en.html.

Jaehnert, S., Wolfgang, O., Farahmand, H., Völler, S., Huertas-Hernando, D., 2013. Transmission expansion planning in Northern Europe in 2030—methodology and analyses. Energy Policy 61, 125–139.

Kall, P., Wallace, S.W., 1994. Stochastic Programming. John Wiley & Sons, Chichester.

Kannan, R., Turton, H., 2012. Cost of ad-hoc nuclear policy uncertainties in the evolution of the Swiss electricity system. Energy Policy 50, 391–406.

Kaut, M., Midthun, K.T., Werner, A.S., Tomasgard, A., Hellemo, L., Fodstad, M., 2014. Multi-horizon stochastic programming. Comput. Manag. Sci. 11, 179–193.

Kaut, M., Wallace, S.W., 2007. Evaluation of scenario-generation methods for stochastic programming. Pac. J. Optim. 3, 257–271.

Kjetsa, E.S., Mo, B., 2015. The value of considering uncertain fuel prices in the profitability evaluation of future HVDC links between the Nordic system and continental Europe, In: Proceedings of the 12th International Conference on the European Energy Market (EEM), 2015, pp. 1–5.

Krey, V., Riahi, K., 2009. Risk hedging strategies under energy system and climate policy uncertainties, Intertom Report IR-09-028. Int. Inst. Appl. Syst. Anal.⟨http://pure.iiasa.ac.at/9121/1/IR-09-028.pdf⟩.

Krook Riekkola, A., Ahlgren, E.O., Söderholm, P., 2011. Ancillary benefits of climate policy in a small open economy: the case of Sweden. Energy Policy 39, 4985–4998.

Lind, A., Rosenberg, E., 2013. TIMES-Norway model documentation. Inst. Energy Technol.⟨http://www.ife.no/en/publications/2013/ensys/times-norway-model-documentation⟩.

Lind, A., Rosenberg, E., Seljom, P., Espegren, K., Fidje, A., Lindberg, K., 2013. Analysis of the EU renewable energy directive by a techno-economic optimisation model. Energy Policy 60, 364–377.

Lindberg, K.B., Doorman, G., 2013. Hourly load modelling of non-residential building

stock. PowerTech (POWERTECH 2013, 1–6.
Loulou, R., 2008. ETSAP-TIAM: the TIMES integrated assessment model. part II: mathematical formulation. Comput. Manag. Sci. 5, 41–66.
Loulou, R., Labriet, M., 2008. ETSAP-TIAM: the TIMES integrated assessment model Part I: model structure. Comput. Manag. Sci. 5, 7–40.
Loulou, R., Lehtila, A., 2012. Stochastic Programming and Tradeoff Analysis in TIMES. TIMES Version 3.3 User Note. Energy Technology Systems Analysis Programme, http://iea-etsap.org/docs/TIMES-Stochastic.pdf.
Loulou, R., Lehtila, A., Kanudia, A., Remme, U., Goldstein, G., 2005a. Documentation for the TIMES model - part III. Energy Technol. Syst. Anal. Program.⟨http://iea-etsap.org/docs/TIMESDoc-GAMS.pdf⟩.
Loulou, R., Remme, U., Kanudia, A., Lehtila, A., Goldstein, G., 2005b. Documentation for the TIMES model - part I. Energy Technol. Syst. Anal. Program⟨http://iea-etsap.org/docs/TIMESDoc-Intro.pdf⟩.
Loulou, R., Remme, U., Kanudia, A., Lehtila, A., Goldstein, G., 2005c. Documentation for the TIMES model - part II. Energy Technol. Syst. Anal. Program.⟨http://iea-etsap.org/docs/TIMESDoc-Details.pdf⟩.
Mo Industripark AS, 2015. El-nettutbygging og konsekvenser for industri og befolkning, http://www.mip.no/2015/el-nettutbygging-og-konsekvenser-for-industri-og-befolkning/.
Munoz, F.D., Hobbs, B.F., Ho, J.L., Kasina, S., 2014. An engineering-economic approach to transmission planning under market and regulatory uncertainties: WECC case study. IEEE Trans. Power Syst. 29, 307–317.
Nagl, S., Fürsch, M., Dietmar, L., 2013. The costs of electricity systems with a high share of fluctutating renewables: a stochastic investment and dispatch optimization model for Europe. Energy J. 34, 151–179.
Nijs, W., Poncelet, K., 2016. Integrating recurring uncertainties in ETSAP energy system models. VITO⟨http://iea-etsap.org/projects/ETSAP%20project%20Recurring%20Risk%20v11.pdf⟩.
Nord Pool Spot, 2014. Mark. data - hydro Reserv.⟨http://www.nordpoolspot.com/Market-data1/Power-system-data/hydro-reservoir1/⟩.
Nord Pool Spot, 2016. FTP server, ⟨http://www.nordpoolspot.com/services/Power-Data-Services/Product-details/⟩.
Norwegian Government, 2013. Long-term Perspectives on the Norwegian Economy 2013, Meld. St. 12 (2012–2013), In: Ministry of Finance (Ed.), https://www.regjeringen.no/en/dokumenter/meld.-st.–12-2012–2013/id714050/.
NTUA, 2016. The PRIMES Model. National Technichal University of Athens, http://147.102.23.135/index.php*option=com_content & view=category & id=35%3Aprimes & Itemid=80 & layout=default & lang=en.
NVE, 2014. Historiske vannføringsdata til produksjonsplanlegging. Nor. Water Resour. Energy Dir.⟨http://www.nve.no/no/Vann-og-vassdrag/Data-databaser/Historiske-vannforingsdata-til-produksjonsplanlegging-/⟩.
NVE, 2015a. Kostnader i energisektoren. Kraft, varme og effektivisering,. The Norwegian Water Resources and Energy Directorate, http://publikasjoner.nve.no/rapport/2015/rapport2015_02a.pdf.
NVE, 2015b. Vannkraftpotensialet pr. 1.1.2015. The Norwegian Water Resources and Energy Directorate, http://www.nve.no/PageFiles/3909/Vannkraftpotensial%202015.pdf*epslanguage=no.
NVE, 2015c. Verneplan for vassdrag. The Norwegian Water Resources and Energy Directorate, http://www.nve.no/no/Vann-og-vassdrag/verneplan/.
Pfenninger, S., Hawkes, A., Keirstead, J., 2014. Energy systems modeling for twenty-first century energy challenges. Renew. Sustain. Energy Rev. 33, 74–86.
Qvist, S.A., Brook, B.W., 2015. Environmental and health impacts of a policy to phase out nuclear power in Sweden. Energy Policy 84, 1–10.
Ravn, H., 2001. The Balmorel Model: Theoretical Background, http://www.eabalmorel.dk/files/download/The%20Balmorel%20Mode%20Theoretical%20Background.pdf.
Ravn, H., 2011. The Balmorel Model Structure, http://www.eabalmorel.dk/files/download/TheBalmorelModelStructure-BMS302.pdf, p. 120.
Rosenberg, E., Espegren, K.A. (Eds.), 2014. CenSES-energiframskrivinger mot 2050, https://www.ntnu.no/documents/7414984/0/CenSES-Energiframskriving+Rapport_final.pdf/13bfdaff-d1ea-4c0f-9553-7bd48ac6fc2f.
Rosenberg, E., Espegren, K.A., 2014. (Eds.). CenSES-energiframskrivinger mot 2050, ⟨https://www.ntnu.no/documents/7414984/0/CenSES-Energiframskriving+Rapport_final.pdf/13bfdaff-d1ea-4c0f-9553-7bd48ac6fc2f⟩.
Rosenberg, E., Lind, A., Espegren, K.A., 2013. The impact of future energy demand on renewable energy production – case of Norway. Energy 61, 419–431.
Seljom, P., Lindberg, K.B., Tomasgard, A., Doorman, G., Sartori, I., 2017. The impact of zero energy buildings on the Scandinavian energy system. Energy 118, 284–296.
Seljom, P., Tomasgard, A., 2015. Short-term uncertainty in long-term energy system models — a case study of wind power in Denmark. Energy Econ. 49, 157–167.
Shi, J., Chen, W., Yin, X., 2016. Modelling building's decarbonization with application of China TIMES model. Appl. Energy 162, 1303–1312.
Simoes, S., Nijs, W., Ruiz, P., Sgobbi, A., Thiel, C., 2016. Comparing policy routes for low-carbon power technology deployment in EU – an energy system analysis. Energy Policy.
Skar, C., Doorman, G., Tomasgard, A., 2014a. The future European power system under a climate policy regime, Energy Conference (ENERGYCON), 2014 IEEE International, pp. 318–325.
Skar, C., Doorman, G., Tomasgard, A., 2014b. Large-scale power system planning using enhanced Benders decomposition, Power Systems Computation Conference (PSCC), 2014, pp. 1–7.
Spiecker, S., Vogel, P., Weber, C., 2013. Evaluating interconnector investments in the north European electricity system considering fluctuating wind power penetration. Energy Econ. 37, 114–127.
Energimyndighet, Statens, 2013. Långsiktsprognos 2012. ER 2013, 03 ⟨https://energimyndigheten.a-w2m.se/Home.mvc⟩.
Statens energimyndighet, 2014. Vad ävgör vattenkraftsverks betydelse for elsystemet - Underlag til nationall strategi för åtgärder innom vattenkrafte, ER2014:12, ⟨http://www.energimyndigheten.se/Global/Press/Energil%C3%A4nkar/Rapport%20ER%202014%2012%20SLUTLIG.pdf⟩.
Statens Energymyndighet, 2012. Färdplan 2050, ER 2012:28, Färdplan 2050.
Statistics Norway, 2016. Energy and manufacturing statistics, ⟨https://www.ssb.no/en/energi-og-industri⟩.
Statistics Sweden, 2016. Annual energy statistics ⟨http://www.scb.se/en_/Finding-statistics/Statistics-by-subject-area/Energy/Energy-supply-and-use/Annual-energy-statistics-electricity-gas-and-district-heating/⟩.
Statnett, 2013. Prisområder (elspot og elbas), ⟨http://www.statnett.no/Drift-og-marked/Kraftmarkedet/Prisomrader-historisk-elspot/Prisomrader/⟩.
Statnett, 2015a. The NordLink cable to Germany, ⟨http://www.statnett.no/en/Projects/NORDLINK/⟩.
Statnett, 2015b. NSN Link, ⟨http://nsninterconnector.com/⟩.
Stavrum, G., 2015. Billig norsk strøm til 750.000 britiske hjem. Nettavisen⟨http://www.nettavisen.no/mener/billig-norsk-strm-til-750000-britiske-hjem/8559523.html⟩.
Sun, N., Ellersdorfer, I., Swider, D.J., 2008. Model-based long-term electricity generation system planning under uncertainty, In: Proceedings of the Third International Conference on Electric Utility Deregulation and Restructuring and Power Technologies, NanJing China, pp. 1298–1304.
Svensk Energi, 2012. Elområden⟨http://www.svenskenergi.se/Elfakta/Elomraden/⟩.
Svensk Energi, 2014. Elåret & Verksamheten 2013. Elåret, 2013 ⟨http://www.svenskenergi.se/Global/Statistik/El%c3%a5ret/Sv%20Energi_el%c3%a5ret2013_versJUNI2014.pdf⟩.
Svensk Energi, 2015. Elåret og Verksamheten 2014. Elåret, 2014 ⟨http://www.svenskenergi.se/Global/Statistik/El%C3%A5ret/El%C3%A5ret%202014_slututg%C3%A5va.pdf⟩.
Vaillancourt, K., Alcocer, Y., Bahn, O., Fertel, C., Frenette, E., Garbouj, H., Kanudia, A., Labriet, M., Loulou, R., Marcy, M., Neji, Y., Waaub, J.-P., 2014. A Canadian 2050 energy outlook: analysis with the multi-regional model TIMES-Canada. Appl. Energy 132, 56–65.
Vattenfall, 2015. Ringhals 1 to be decommissioned in 2020 and Ringhals 2 in 2019, ⟨http://corporate.vattenfall.com/press-and-media/press-releases/2015/ringhals-1-to-be-decommissioned-in-2020-and-ringhals-2-in-2019/⟩.
Warland, G., Haugstad, A., Huse, E.S., 2008. In: cluding thermal unit start-up costs in a long-term hydro-thermal scheduling model, Proceedings of the 16th Power Systems Computational Conference, Glasgow, p. 6.
Wolfgang, O., Haugstad, A., Mo, B., Gjelsvik, A., Wangensteen, I., Doorman, G., 2009. Hydro reservoir handling in Norway before and after deregulation. Energy 34, 1642–1651.
Zhang, H., Chen, W., Huang, W., 2016. TIMES modelling of transport sector in China and USA: comparisons from a decarbonization perspective. Appl. Energy 162, 1505–1514.