The impact of Zero Energy Buildings on the Scandinavian energy system

Pernille Seljom*[a,b] (Pernille.Seljom@ife.no), Karen Byskov Lindberg [c,d] (karen.lindberg@ntnu.no), Asgeir Tomasgard [a] (asgeir.tomasgard@iot.ntnu.no), Gerard Doorman [c] (gerard.doorman@ntnu.no), Igor Sartori [e] (igor.sartori@sintef.no)

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
c) Department of Electric Power Engineering
   Norwegian University of Science and Technology (NTNU)
   7491 Trondheim
   Norway
d) The Norwegian Water Resources and Energy Directorate (NVE)
   Post box 5091 Majorstuen
   0301 Oslo
   Norway
e) SINTEF Building and Infrastructure
   Post box 124 Blindern
   0314 Oslo
   Norway

*Corresponding author:
Pernille Seljom, Tel.: +47 99 02 02 63, pernille.seljom@ife.no

Abstract

This paper investigates how an extensive implementation of net Zero Energy Buildings (ZEBs) affects cost-optimal investments in the Scandinavian energy system towards 2050. Analyses are done by a stochastic TIMES model with an explicit representation of the short-term uncertainty related to electricity supply and heat demand in buildings. We define a nearly ZEB to be a highly efficient building with on-site PV production. To evaluate the flexibility requirement of the surrounding energy system, we consider no use of energy storage within the ZEBs. The results show that ZEBs reduce the investments in non-flexible hydropower, wind power and Combined Heat and Power, and increase the use of direct electric heating and electric boilers. With building integrated PV production of 53 TWh in 2050, ZEBs increase the Scandinavian electricity generation by 16 TWh and increase the net electricity export by 19 TWh. Although the increased production reduces the electricity prices, the low heat demand in ZEBs gives a drop in the electricity consumption by 4 TWh in 2050. Finally, the results demonstrate that the Scandinavian energy system is capable of integrating a large amount of ZEBs with intermittent PV production due to the flexible hydropower in Norway and Sweden.

Highlights:

- We analyse cost-optimal integration of ZEBs in the Scandinavian energy system.
- We capture impact of short-term uncertainty on long-term investment decisions.
- ZEBs reduce the investments in the electricity and heating sector.
- The Scandinavian electricity sector is capable of integrating ZEBs with PV.
- The operation of the flexible hydropower is changed with ZEBs.

Key Words:

Zero Energy Building; TIMES model; Stochastic programming; Photovoltaic power; Energy system model

1 Introduction

A net Zero Energy Building (ZEB) is a building with low energy demand that produces, on an annual basis, as much renewable energy as its energy consumption [1, 2]. This paper presents the cost-optimal adaption of an extensive introduction of ZEBs in the Scandinavian energy system towards 2050. To study this, we have developed a stochastic TIMES (The Integrated MARKAL-EFOM System) model [3-7], with an explicit modelling of the short term-uncertainty related to electricity generation and heat demand in buildings.

1.1 Research motivation

Implementation of ZEBs is identified as one of the remedies to meet the Energy Strategy of the European Union, and according to the Energy Performance of Buildings Directive (EPBD), all new buildings shall be 'nearly' ZEBs from 2020 [8]. The initial experiences with ZEBs show that Photovoltaic electricity (PV), integrated in the façade and roof of the building, has been a propitious solution to produce energy in ZEBs [9, 10]. This leads to challenges for the surrounding energy system since ZEBs may export electricity in periods of high PV production and import electricity when the solar radiation is low. In Scandinavia the electricity consumption in buildings is highest in winter when the solar conditions are poor. Hence, the electricity sector will serve as a seasonal storage for the ZEBs, where excess electricity from a ZEB is supplied to the electricity grid in summer, and electricity is provided from the grid to the ZEBs in winter.

The energy system needs to consider the reduced heat demand and the on-site electricity generation with an integration of ZEBs. This implies that the existing energy system needs to adapt with respect to both operation and future investments. Although the net energy demand of the ZEBs is low, the existing electricity capacity might need to be maintained, as the ZEBs do not necessarily lower the peak electricity demand.

Abbreviations

CHP	Combined Heat and Power
DH	District Heat
EPBD	Energy Performance of Buildings Directive
HP	Heat Pump
PV	Photovoltaic electricity (solar power)
PE	Primary Energy
TIMES	The Integrated MARKAL-EFOM System
ZEB	net Zero Energy Building

However, the low heat demand in ZEBs, caused by energy efficiency measures, can reduce the peak electricity demand.

The electricity mix in Scandinavia is unique. Denmark is the EU nation with the largest share of electricity generation from Combined Heat and Power (CHP) and wind power at 65 % and 35 % respectively in 2013 [11]. The electricity generation in Norway and Sweden is also distinctive, as the two countries have the largest hydro production among the EU countries, with 129 TWh and 61 TWh in 2013 [11], and have about 70 % of the European hydro storage capacity with 82 TWh and 34 TWh respectively [12]. Due to flexible CHP plants, hydro reservoirs and an integrated electricity grid, the Scandinavian countries are well suited to integrate a larger share of intermittent PV production caused by ZEBs. Hence, it is interesting to study how, and to what extent, hydro production and other renewable energy technologies adapts to an extensive introduction of ZEBs. With a low energy demand and on-site energy production, ZEBs might impact the cost-optimal investments in the overall energy system and change the operation pattern of the flexible production technologies. In order to quantify these changes, an extensive analysis on the aggregated system level is needed. It is assumed that a large share of ZEBs influences the electricity price, and thereby affects both investments in the electricity sector and in heating technologies within buildings, including ZEBs. Consequently, it is important to evaluate the cost-optimal heating design in buildings together with its interaction with the remaining energy system.

1.2 Recent studies and scope of study

This section presents literature that is related to the scope of this paper. The first part focus on the energy system with ZEBs and the second part motivates for the applied stochastic methodology.

1.2.1 Energy systems with ZEBs

The literature concerning ZEBs is mostly related to a single building, investigating e.g. the architecture and building envelope, and/or the energy technologies within the building. Congedo [13] and Evola [14] investigate cost-effective building design alternatives for nearly ZEBs, considering different materials and thickness for the respective building elements, but has no integrated optimisation approach. Milan [15] and Lindberg [16, 17] treat the building envelope as given, and investigate the energy system design of the ZEB using linear optimisation. Hamdy [18], Lu [19] and Zhang [20] have developed different kinds of multi-objective or multi-stage optimisation approaches, first finding the cost-efficient building envelope and secondly the energy system design within the ZEB.

Literature that investigates ZEBs in the national or regional energy system is scarce. The presented literature above do not consider that the energy related decisions in a ZEB can have an impact on the surrounding energy system, as for example changing the electricity price. This can be a reasonable assumption with a limited share of ZEBs in the building sector, but is less valid with an extensive implementation of ZEBs. To capture such feed-back effects, this paper uses a methodology that optimises the interaction between the building sector and the surrounding energy system including endogenous investment decisions in the building, electricity and district heat sector. There are however related studies, such as Henning [21] and Palzer [22] ,that evaluate the cost-optimal evolvement of the energy system with significant renewable electricity generation and increased energy efficiency measures in the building sector, reaching a target of 50 % reduction of a country's primary energy consumption.

1.2.2 Stochastic modelling approach

The existing literature using long-term energy system models of Scandinavia, including [23-29], apply a deterministic modelling of short-term uncertainty. Unlike our stochastic approach, a simplified deterministic model includes only one operational situation and provides investment decisions that do not directly take into account a range of operational situations which can occur. It is therefore unclear whether the results from deterministic models are valid with the presence of short-term uncertainty. This is supported by Seljom [30] that concludes that the method used to represent the unpredictable characteristics of wind power in investment models can significantly affect the model results. A stochastic approach to incorporate short-term uncertainty in TIMES was first introduced in Loulou [31] and is used to represent intermittent wind capacity in Seljom [30]. This approach provides cost-optimal investment decisions, which are valid for a range of representative operational situations. For a realistic representation of the grid interaction of a ZEB and the surrounding energy system, we apply a stochastic representation of short-term uncertainty of electricity supply and heat demand in buildings.

There are studies, focusing only on the electricity sector, that have incorporated a stochastic modelling of the short-term uncertainty of intermittent renewables in investment models. For example, Nagl [32] apply stochastic modelling of wind power and PV in a combined investment and dispatch optimization 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 [33-37]. As this literature does not include investments in the building sector, they do not include a stochastic representation of heat demand in buildings. It is however appropriate to consider the uncertainty of heat demand, when analysing the interaction of ZEBs with the surrounding energy system, as the heat demand is highly dependent on the outdoor temperature.

1.3 Outline

The remainder of this paper is structured as follows; Section 2 gives an overview of the methodology and Section 3 is devoted to the model cases that are used in the analyses. Finally, the results are presented in Section 4 and the conclusions are given in Section 5.

2 Methodology

First, this section gives an overview of the model structure and assumptions of the TIMES model. Thereafter, we present the applied definition and assumptions of ZEBs. Finally, we provide an overview of the applied stochastic methodology, including the scenario generation of the uncertain parameters.

2.1 Model structure and assumptions

TIMES is a bottom-up optimisation modelling framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. It is mainly used for medium- and long-term analysis on global, national and regional levels, including the Energy Technology Perspectives published by the International Energy Agency [38]. The model minimizes the total discounted cost of the energy system to meet the demand for energy services. The model decisions are made with full knowledge of future events and suppose free competition with no market imperfections. To provide the macroeconomic cost-optimal solution, we exclude current policy instruments, including taxes and subsidies. The annual discount rate is set to 4 %.

To represent the current structure of the electricity market, the model is regionally divided into the Nord Pool price areas, as shown in Figure 1. To analyse the long-term impact of ZEBs, we use a time-horizon from 2010 to 2050, with investment and operational decisions in each five-year model period of the time-horizon. To consider seasonal and daily variations in energy supply and demand, each model period is represented by 12 two-hour steps for a representative day of four seasons: winter (December, January and February), spring (March, April and May), summer (June, July and August) and autumn (September, October and November), giving 48 time-slices in total. While investments are made for each model period, the operational decisions are optimised on the two-hourly daily level to satisfy the energy demand at least cost.

The model includes a set of technologies to transform energy sources to final demand, including conversion processes such as electricity and heat generation technologies and demand technologies as for example boilers and vehicles. The characterisation of the energy technologies, as cost data and efficiencies, are exogenous input to the model and are inter alia based on [39, 40].

Future energy demand of heat, transport and non-substitutable electricity are exogenous input to the model and are based on reference energy projections for Denmark [41], Norway [42] and Sweden [43, 44]. Due to different data availability, the heat demand is divided differently for the Scandinavian countries. The heat demand is split into three categories for Denmark; central district heat, de-central district heat and individual buildings, in six categories for Norway; commercial buildings, single family house, multifamily house, metal industry, pulp and paper and other industry, and into four categories for Sweden; buildings, district heat, forest industry and other industry. With the explicit modelling of the DH demand in Denmark and Sweden, we do not capture the competition between district heat and other heating options, e.g. if it is profitable to expand the DH grid to replace the natural gas grid. The electricity consumption, beyond the non-substitutable electricity demand, is an endogenous model decision since it is an option to use electricity to produce heat in the district heat and building sector.

Projected energy prices for biomass, fossil fuels and electricity in European countries are based on [45], and are summarised in Appendix A. Note that the electricity prices within the Scandinavian regions are endogenous, as they are the dual values of the electricity balance equation. However, the electricity prices in the countries with trading capacity to Scandinavia are exogenous, and it is assumed that these electricity trade prices are independent of the quantities traded to Scandinavia.

Figure 1 shows the existing and proposed transmission capacity to the countries outside Scandinavia. The transmission capacity within and outside the model regions reflects the current capacity. The model can choose to invest in new capacity expansions to Europe, but the capacities within the Scandinavian model regions are fixed. The on-going project from Sweden to Lithuania, “NordBalt” [46], is included as model input, while investments in the projects, “VikingLink” between Denmark and the United Kingdom [47], “NSN” between Norway and the United Kingdom [48] and “NordLink“ between Norway and Germany [49] are endogenous options. Note that the electricity trade is modelled in a simplified manner, without considering Kirchhoff's laws, and the electricity loss is set as a given percentage of the electricity consumption; 3 % on a high voltage level and 7 % on a lower voltage level.

Two types of hydropower plants are included; flexible plants and non-flexible plants. The non-flexible plants have a seasonal availability factor that reflects the average seasonal production over the installed generation capacity. The non-flexible electricity production is set identical for all days within a season, assigning these plants no flexibility. The flexible hydropower plants have an annual availability factor, reflecting the annual production over the installed capacity, and are flexible to distribute their production over the sub-annual time-slices of the model. Finally, the seasonal production of the flexible hydropower plants, are limited to a maximum and minimum level according to historical production data.

2.2 Modelling of ZEBs

A ZEB is a highly energy efficient building with on-site renewable energy generation. Hence, a ZEB is characterised by low energy demand due to e.g. high airtightness and considerable insulation, which is also the case for passive buildings. According to the Norwegian definition, the annual space heat demand of a residential passive building is limited to 29 kWh/(m^{2}y) when located close to Oslo [50]. For a non-residential building in Norway, as an office building, the maximum allowable net heat demand for space heating is about 30 kWh/(m^{2}y), but varies with building category and geographical location.

The energy balance of a ZEB is typically calculated as the energy consumed minus the energy generated over a year [51]. The annual energy balance reflects the difference between the weighted sum of the imported energy carriers consumed in the building, and the weighted sum of energy carriers exported from the building, as denoted in Equation (1). The amount of imported or exported energy, y_i, are multiplied with a Primary Energy (PE) factor, f_i, for each of the respective energy carriers, i. As an example, the PE factor for electricity is 2.5 for average European conditions [1], but each member state can define its own PE factors. Further, the EPBD states that the buildings shall be 'nearly' zero, meaning the balance, *D*, may be positive. The value of *D* is a member state decision.

$$\underbrace{\sum_{i \in I} f_i \cdot y_i^{\text{import}}}_{\text{weighted energy import}} - \underbrace{\sum_{i \in I} f_i \cdot y_i^{\text{export}}}_{\text{weighted energy export}} = \underbrace{D}_{\text{balance}} \qquad (1)$$

A consistent handling of PE factors for all Scandinavia is a challenging task since Denmark has decided on different PE factors than Sweden while Norway has not defined any factors [10]. In addition, if the PE factors represent the environmental impact of the use of an energy carrier, the factor should be a model decision rather than a model input. For example, the PE factor of electricity depends on the share of renewables in the electricity generation mix, which is a model output. Findings from [17] shows that the electric specific demand of a multi-family ZEB accounts for 80 % of its total primary energy consumption if heated by a heat pump. For this case, a ZEB definition which only includes the electric specific demand, gives an energy generation which accounts for 80 % of the total energy consumption of the building. For comparison, using the Danish ZEB definition, which only includes heat demand and lighting, on the same case, requires on-site energy generation which accounts for 28 % of the total energy consumption of the building. This indicates that a ZEB definition that accounts for the electric specific demand only, is stricter than the Danish ZEB definition.

For a manageable definition of ZEBs, we assume the energy requirement of a 'nearly ZEB' only includes the electric specific demand of the building. With this assumption, both the import and export of the ZEB balance, as shown in Eq. 1, is electric, and the use of PE factors is avoided. Consequently, the annual energy generation equals the annual electric specific demand in a ZEB.

Further, we assume a ZEB to be a passive building, according to the Norwegian definition [50, 52] with on-site PV production. In order to evaluate the maximum flexibility required by the surrounding energy system, we consider no use of energy storage within the buildings. Hence, the difference between electricity supply and demand in a ZEB is handled by trade with the electricity grid.

2.3 Model input on energy demand in buildings and PV capacity

The model input on energy demand in buildings is separated into heat demand and electric specific demand. The electric specific demand includes electricity that is non-substitutable with other energy carriers, such as electricity for lighting and equipment. Based on findings in [53, 54], and the fact that the electric specific demand of Swedish households, according to the Swedish Energy Agency, has been relatively stable since 1990, we conclude that it is mainly the heat demand that is reduced when introducing ZEBs and the electric specific demand is unaffected.

Considering current rehabilitation rates, new construction rates and demolition rates, if all new buildings and some of the rehabilitated buildings towards 2050 become ZEBs, ZEBs contributes to 25 % in 2030 and 50 % in 2050 of the total building stock. Table 1 shows the corresponding impact of ZEBs on the annual heat demand for each of the Scandinavian countries in 2015, 2030 and 2050. Since the heat demand is temperature dependent, the figure includes both the expected heat demand, based on average temperatures, together with the minimum and maximum outcome of heat demand. Compared to no implementation of ZEBs, the heat demand is reduced by 8 % in 2030 and by 18 % in 2050 with ZEBs. In 2050, the annual heat demand with ZEBs ranges from 145 TWh to 183 TWh, dependent on realisation of the outdoor temperature. Please note that the indicated model cases in the tables below are defined in Section 3.

Table 2 shows the model input for electric specific demand in 2030 and 2050, with the corresponding model input on PV capacity. In Scandinavia, the electric specific demand in buildings is 100 TWh in

2030 and 106 TWh in 2050. The PV capacity is derived from our ZEB definition, where the PV capacity is set such that the annual PV production equals the annual electric specific demand within each region. With a 50 % share of ZEBs in the building sector in 2050, the electricity specific demand and the annual PV production in ZEBs is 53 TWh, corresponding to 63 GW installed PV capacity.

As TIMES optimises all parts of the energy system simultaneously with a macro-economic perspective, the model is indifferent to whether the electricity generated from PV is supplied within the building or centrally. To reduce the computational complexity, we model the PV production in ZEBs as electricity supply to the electricity grid. The disadvantage with this approach is that it overestimates the electricity losses and trade costs related to the electricity generation in ZEBs.

2.4 Stochastic modelling approach

We apply a two-stage stochastic model [55, 56] to provide cost-optimal investments that explicit consider the short-term uncertainty of the following stochastic parameters: PV production, wind production, hydro production, heat demand in buildings and the electricity prices outside Scandinavia. The electricity prices represent the short-term uncertainty of the market equilibrium in the countries with interconnection to Scandinavia. The listed parameters are selected to give an appropriate representation of the grid interaction of ZEBs, which depend on intermittent electricity supply and a climate dependent heat demand. Each uncertain parameter is represented by 21 possible realisations, called scenarios, with equal probability to occur. The scenarios are generated by random sampling, with adjustments to ensure selected statistics properties, as described in Section 2.4.1-.2.4.5. The number of scenarios is primarily chosen for a manageable computational time, although a higher number of scenarios can increase the quality of the results [57].

Figure 2 illustrates a scenario tree with the information structure of the two-stage stochastic model. At the first stage, the realisation of the operational scenarios is unknown and investments in new capacity for the entire model horizon, from 2010 to 2050, are made. At the second stage, starting at the branching point of the scenario tree, the outcomes of the different scenarios are known, and operational decisions are made for each of the scenarios for all model periods. Consequently, the investments are identical for all scenarios, whereas operational decisions are scenario dependent. To consider the different operational situations in the optimisation, the model minimise the investment costs and the average of the operational costs for all scenarios. This gives investment decisions that recognize 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, and we apply a multi-horizon model structure [58], with no dependency of the operational decisions between the model periods. Unlike a stochastic approach, a simplified deterministic model has only one operational scenario. Consequently, the investment decisions in a deterministic model do not take into account a range of operational situations that can occur.

As this is a long-term investment model, the scenarios are designed to represent realistic operational situations and not to forecast the future. Therefore, the construction of the scenarios is based on historical data instead of using a prediction model. The hydro production and heat demand scenarios are modelled as dependent since climatic conditions affect both the inflow to the hydro reservoirs and the heat demand in buildings. The other uncertain parameters are modelled as independent due to limited data availability. Consequently, we do not capture the correlation between hydro production, PV production and wind production in Scandinavia with the European electricity prices. However, as the Scandinavian energy system is relatively small, compared to the rest of Europe, the electricity generation in these countries has limited influence on the European electricity prices. Another model adjustment, caused by limited data availability, is that the uncertain parameters are independent between the model periods. This implies that there are no dependency between the wind conditions in 2030 and the wind conditions in 2035. Nevertheless, the scenario generation method is designed to explicit capture the regional and time-slice correlation of the uncertain parameters. This is elaborated in the sections below, which describes the scenario generation methodology of each of the uncertain parameters.

2.4.1 PV production

The PV scenarios consist of hourly availability factors, which equal hourly PV production over installed capacity, for each model region. First, historical, availability factors from 2014 are derived by dividing hourly production data by the installed capacity. 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. In Denmark and Sweden, the grid operator provides data on PV production on an hourly level [59, 60], whereas PV production data for Norway is scarce [61]. To handle this, we have generated artificial Norwegian PV data based on the Swedish availability factors and simulated availability factors for Norway and Sweden from [62]. As Norway and Sweden are roughly located at the same latitude, we assume that the PV characteristics of the Norwegian regions are similar to the PV characteristic of the closest located Swedish region.

For each model period, the scenarios are generated by a random sample of 21 days within each season. Thereafter, the corresponding 12 two-hourly availability factors of the sampled day are used. To ensure that the scenarios have the same mean value as the historical data, the availability factors are adjusted such that the average annual availability factor, within each region, is identical the observed annual availability factor of 2014. Consequently, for each model period, region and season, the PV scenarios consist of 21 different daily realisations of the PV production. Note that this approach ensures a consistent daily correlation, since each scenario consists of 12 two-hourly chronological values. Further, because the same sampled days are used for all model regions, we explicitly capture the correlations between the model regions.

Although the number of scenarios is limited, we consider the 21 scenarios as representative to indicate a range of daily PV production profiles. Figure 3 illustrate the characteristics of the model input on PV availability factors in the Swedish region with highest population, SE3, for summer in 2030, by showing the 25/75 quantile, minimum, maximum and median of the daily realisations in the 21 stochastic scenarios The figure shows clearly that the availability factors vary significantly between the scenarios and time of the day. For example at 12:00, when the PV production peaks for most scenarios, the availability factor ranges from 0.03 to 0.20. Here, the difference in availability factors is mostly due to different cloud covers.

2.4.2 Wind production

The wind scenarios consist of hourly availability factors, which equal the hourly wind production over the installed wind power capacity, for all model regions. The scenarios are based on historical production data from 2012 to 2014 [59, 60, 63]. Besides a larger data set, with three years of data instead of one, the scenario generation method for wind production is identical to the generation of the PV scenarios that are described in Section 2.4.1.

2.4.3 Hydropower production

The hydro scenarios contain seasonal availability factors in all regions, which reflect the seasonal hydropower production over the installed hydro capacity, and are based on historical data from 2001 to 2014 [64, 65]. For each model period, a scenario is generated by random selection of a year among the 14 historical years. In each region, the corresponding seasonal availability factor is used in all seasons for the non-flexible plants, and the corresponding annual availability factor is used as a model input for the flexible plants. This approach is designed to ensure the correlation of hydro production between model regions, seasons and hydro plant types. To ensure that the hydro scenarios are representative with respect to the statistical mean, we have controlled that the average availability factor of all scenarios, over all model periods, is in accordance with the historical data.

2.4.4 Heat demand

The heat demand scenarios contain hourly load profiles that are based on simulated hourly heat demand for 14 historical climatic years. The simulations are done by use of regression models and historical outdoor temperatures from 2001 to 2014 for a representative location within each model region. The methodology used to develop the regression models for non-residential buildings is described in [54], which detects the temperature dependency of the heat demand by using hourly measurements of heat consumption and outdoor temperature. A similar regression model, based on [66], is developed for residential buildings. The regression methodology is also applied to measurements of passive buildings, which enable us to adjust the regional hourly heat demand to different deployment of passive buildings in the building stock. Although the parameters of the regression models are based on Norwegian conditions, we assume they are valid to derive hourly heat demand for all the Scandinavian model regions.

The scenarios of the annual heat demand are constructed by selecting the heat demand simulated for the same 21 historic years that were sampled for the hydro scenarios. This is to capture the correlation between the climate dependent hydro inflow and the outdoor temperature. To represent the heat demand variations within each season and time of day, one day within each season is randomly selected for each scenario. Finally, for each model period, the scenarios are adjusted such that the expected value of all scenarios equals the annual expected heat demand as specified in Table 1.

To illustrate the model input, Figure 4 shows the characteristics of the heat load profiles for non-residential buildings for NO1 in 2050, with 0 % and 50 % of the building stock being ZEBs, by showing the 25/75 quantile, minimum, maximum and median of the 21 different daily realisations. The plot demonstrates that the heat demand varies significantly by time of day, by scenario and by the share of ZEBs. For example at 10:00, the heat demand ranges from 168 GWh to 381 GWh with 0 % ZEBs, and from 135 GWh to 308 GWh with 50 % ZEBs.

2.4.5 Electricity prices outside Scandinavia

The scenarios for the electricity prices outside Scandinavia are based on hourly electricity prices from 2014 in Germany, Netherlands, Finland, Lithuania, Poland and United Kingdom. We use the same sampling method as applied to generate the PV scenarios in Section 2.4.1 to generate the electricity price scenarios. After the scenarios are sampled, the model input is adjusted to the hourly prices in each trading region, such that the average of the scenarios is consistent with the assumed annual electricity price, as specified in Appendix A, for all model periods.

Further, it is likely that there will be an implementation of ZEBs with PV not only in Scandinavia but also in Europe, and that their PV production affects the traded electricity prices towards Scandinavia. Several studies, including [67-69], indicate that more intermittent electricity generation, as PV, can increase both the average electricity price and the price volatility. However, others, as [70, 71], states that the annual electricity price can be reduced with more intermittent electricity production. In this study, we assume that a large introduction of ZEBs with PV, increases the volatility of the hourly European electricity prices, but leave the average price unaffected. We propose a methodology that changes the price profile proportional to the solar radiation in the different European countries. This approach implies fitting a cubic equation such that the electricity trade price is unaffected when there is no PV production, and reduces the price to zero in the scenario with the highest PV production in 2050. The scenarios for the solar radiation in all trading countries are based on national hourly solar radiation simulations from [62].

The resulting 25/75 quantile, minimum, maximum and median of the 21 stochastic price scenarios for Germany in summer 2050 are plotted in Figure 5, with and without influence of ZEBs with PV in Europe. ZEBs decrease the prices in the hours with solar radiation, increase the price at night and thus cause larger price variability. For example, the average price at 02:00 is 49 EUR/ MWh without ZEBs, and 85 EUR/ MWh with ZEBs. Since the solar radiation is scenario dependent, the price impact of ZEBs varies greatly within each hour of the day. For example with ZEBs, the electricity price ranges from 5 EUR/ MWh to 73 EUR/ MWh at 12:00.

3 Model cases

In this study, we analyse five model cases with different model input on the heat demand, PV production and European electricity prices, representing different long-term trends in the Scandinavian building sector and the European energy system. We emphasise that the model cases and stochastic scenarios are two different types of model input. Each model case apply the same stochastic scenarios, that are described in Section 2.4, to explicitly capture the stochastic nature of i.e solar radiation, wind speed and outdoor temperature. As shown in Figure 2, there is one investment decision for each model case, based on 21 possible outcomes of the uncertain parameters. However, the investment decisions can differ with the various the model cases, as shown in Section 4.

The main characteristics of the model cases are summarised in Table 3. The first case is a reference case, denoted *REF*, with no implementation of ZEBs. For this case, we assume a gradual increase of energy efficient buildings with 10 % in 2030 and 20 % in 2050 to take into account that an increasing share of the building stock has the current building standard in the future. These numbers are derived by the methodology described in [72] and are provided by the Norwegian Water Resources and Energy Directorate. In the *ZEB* case, all new buildings and some of the rehabilitated buildings have a passive building standard and on-site PV installed, corresponding to 50 % of the Scandinavian building stock being ZEBs in 2050. In this model case, we assume that ZEBs are introduced in the same order of magnitude in the rest of Europe as in Scandinavia, and influence the European electricity prices as presented in Section 2.4.5. To differentiate the impact of the two characteristics of a ZEB; reduced heat demand and increased on-site PV production, we include two additional model cases. The *PBU* case includes the passive building standard of the ZEBs but has no on-site PV production. Opposite, the *SUN* case includes the on-site PV capacity of the ZEBs without the implementation of the passive building standard. Finally, to differentiate the influence between the Scandinavian ZEBs and the change in European electricity prices, we evaluate the impact of ZEBs with no change in the European electricity prices in a separate case, *ZEB**. Consequently, this case represents a situation with a large implementation of ZEBs in Scandinavia and no implementation of ZEBs in the rest of Europe.

The model input on heat demand and PV capacity for the various model cases are given in Section 2.3. For all model cases except *REF* and *PBU*, the PV capacity is according to Table 2. The heat demand is shown in Table 1, with a lower heat demand for *PBU*, *ZEB, and ZEB** compared to *REF* and *SUN*, due to the implementation of the passive building standard. The model assumptions for the electricity prices outside Scandinavia are presented in Section 2.4.5. Note that since the heat demand and PV capacity are exogenous model input, we do not consider the additional cost related to a passive building standard and on-site PV production.

4 Results and discussions

This section presents and discusses the results of the model cases to evaluate the effects of a large introduction of ZEBs in the Scandinavian energy system. First, the effects on the electricity and building sector are explained in Section 4.1 and Section 4.2, respectively. Second, the system integration of ZEBs in Scandinavia is discussed; the system adaption of PV production in Section 4.3, and the impact on system costs in Section 4.4. Third, the impact of using a stochastic modelling approach is presented in Section 4.5. Finally, in Section 5 we give our conclusions. If not otherwise specified, the results report the expected value of the operational decisions, i.e. the average of the operational decision of the 21 stochastic scenarios.

4.1 The electricity sector

ZEBs increase the total electricity generation in Scandinavia, giving a drop in the electricity prices. This lowers the incentives for investments in new generation capacity. In Norway and Sweden, the price drop is significant, due to limited transmission capacity to the neighboring regions together with the long lifetime of the hydropower and nuclear power, with low reinvestment needs. Whereas in Denmark, the price drop is lower and more temporarily, as the existing electricity plants are phased out towards 2050. Nevertheless, given our model assumptions on the European electricity prices, Denmark find it cost-optimal to investments in new electricity generation capacity, also with an extensive implementation of ZEBs.

Table 4 provides the national electricity balances in 2050 for all model cases. On a Scandinavian level, an introduction of ZEBs increases both the annual electricity generation and the electricity export to Europe, but has a minor impact on the electricity consumption. The effect on the electricity consumption is two-sided. On the one hand, the passive building standard reduces the heat demand and thus electricity used for heating. On the other hand, the PV production decreases the electricity price, which incentivises substitution towards electric heating. In total, the electricity consumption is 4 TWh lower with ZEBs in 2050, corresponding to a 1 % lower heat demand for *ZEB* compared to *REF*. Comparing *REF* to *ZEB* on a Scandinavian level, the electricity generation increases by 16 TWh, giving an increase in the net export by 19 TWh.

Figure 6 depicts the installed electricity generation capacity by technology, in 2010, 2030 and 2050 for all model cases. Note that the nuclear capacity in all cases and the PV capacity for *SUN*, *ZEB* and *ZEB**, is a model input and not a model decision. The total capacity is significantly increased with an implementation of ZEBs due to the on-site PV. Nevertheless, the electricity capacity in CHP, wind power and non-flexible hydropower are lowered, whereas investments in flexible hydropower capacity are unaffected. Comparing *REF* and *ZEB*, the investments in non-flexible hydropower are reduced with 13 % in 2030 and 16 % in 2050. Note that this is given our assumption that current hydro capacity remains available towards 2050. The lower investments in CHP plants are mainly caused by the passive building standard as it decreases the district heat demand. For example compared to *REF* in 2050, the CHP capacity is 1.2 GW and 1.5 GW lower in *PBU* and *ZEB* respectively. Further, we conclude that the PV production has a greater influence than the passive building standard on the wind investments. Compared to *REF* in 2050, the wind capacity is reduced with 3.7 GW in *PBU*, 7.6 GW in *SUN* and 9.0 GW in *ZEB*. Although PV constitutes a large part of the installed capacity, it has a smaller share of the electricity production mix. For *ZEB*, PV corresponds to 45 % of the installed capacity, but only 14 % of the electricity generation in 2050.

There are large regional differences in wind investments. This is illustrated in Figure 7 that shows the national wind power capacity in 2015, 2030 and 2050 for all model cases. For *ZEB*, the wind capacity is considerably larger in Denmark with 6.0 GW, compared to Norway and Sweden, with 1.1 GW and 1.5 GW respectively in 2050. This is a consequence of the regional differences in reinvestment needs towards 2050. Even though the wind capacities are reduced with ZEBs, the share of renewable electricity generation, including hydro, PV and wind, increases from 78 % in *REF* to 81 % in *ZEB*.

The results show that PV is not a competitive technology in *REF* and *PBU*, with an investment cost at 2.1 EUR/W in 2015 declining to 1.5 EUR/W in 2050. For these model cases, a substantially cost reduction is needed for investments in PV. The regional differences in the electricity sector and the transmission capacity give regional differences in cost-competitive investment of PV. For *REF*, this investment cost ranges from 0.3 EUR/W in NO4 to 1.0 EUR/W in DK2 in 2050.

An implementation of ZEBs changes the operation of the flexible electricity generation and gives a different electricity trade pattern with Europe. This is illustrated in Figure 8 where the net electricity export from Scandinavia in spring for 2050 is plotted for *ZEB* and *ZEB**. For *ZEB**, with European electricity prices according to the current price profiles, Scandinavia exports at daytime when prices are high and imports at night when prices are low. In contrast, for *ZEB*, with low electricity prices in periods of high PV production, Scandinavia exports at night and imports electricity from Europe at day. Nevertheless, as the annual electricity price is the same for all model cases, the total net export is in a similar range at 52 TWh in *ZEB** and 49 TWh in *ZEB*. This demonstrates that the Scandinavian energy system, with a considerable amount of flexible hydro production capacity, can adapt to substantial changes in the European electricity prices.

4.2 Heating technologies in buildings

The passive standard, the on-site PV production and the development of the European electricity prices influence the heat technologies and heat supply in buildings. Figure 9 illustrates the installed heat capacity for all model cases. Here, the connection capacity to district heat is not included as the district heat demand is exogenous, and the technology group named *Electricity* includes both electric boilers and direct electric heating. As the heat demand is reduced with ZEBs, the heat capacity is lowered by 9.0 GW in *PBU* and 7.0 GW in *ZEB* when compared to *REF* in 2050. For *SUN*, the heat capacity is 2.3 GW higher in 2050 when compared to *REF*, despite that these model cases have the same heat demand. The increased capacity is caused by the altered variability of the European electricity prices, giving more investments in low-cost electric heating. Note that these results are based on an aggregated representation of the building stock by model region, and further work needs to address the effects on installed heat capacities on a local level.

Figure 10 shows the annual heat supply to buildings in 2030 and 2050 for all model cases. The majority of heat supplied by natural gas occurs in Denmark and Sweden, and biomass used for heating consists primarily of wood used in the cold winter season. The main differences, when comparing *REF* to *ZEB*, is that heat supplied by heat pumps (HP), gas and biomass boilers and wood stoves, is reduced, whereas the low-capital electricity heat generation is unchanged. However, as the total heat demand is lower in a ZEB, the share of direct electric heating increases from 16 % in *REF* to 20 % in *ZEB* in 2050. The results also indicate that the use of low-capital electricity heat increases with more variability of the European electricity prices, as the installed capacity of *Electricity* in 2050 is 0.8 GW higher in *ZEB* compared to *ZEB**.

4.3 System integration of PV production

With PV contributing to 14 % of the total electricity generation in Scandinavia in 2050, situations when it is not feasible to utilise all PV production or other non-flexible electricity generation may occur. This is due to grid constraints between the model regions in hours with high PV production, and a relative low electricity demand. This situation is illustrated in Figure 11, which shows the electricity balance for region SE3 for a random summer day in 2050 for *ZEB*. The difference between supply (regional production plus import into the region) and demand (regional consumption plus export out of the region) peaks in the middle of the day when the solar radiation is at its highest, with 7.5 GW at 14:00. For this hour, PV contributes to 90 % of the regional electricity generation where the remaining electricity generation consists of non-flexible hydropower, nuclear power and industrial CHP plants. Accumulated for this specific day, 20 % of the non-flexible electricity generation is unutilized, that is mainly caused by the PV production between 10:00 – 14:00.

Note that Figure 11 shows a summer day with an extreme high share of unutilized PV. On an annual level, only 0.4 % of the total electricity consumption or 2.4 % of the PV production, in 2050 is unutilised due to limitations in the transmission grid for *ZEB*, corresponding to 1.3 TWh. The unutilised PV occurs in 2.6 % of the 1008 operational time slices (12 daily periods *4 seasons *21 scenarios) in 2050, mostly in summer with a few instances in fall. There are however regional differences in the occurrence of unutilised electricity, ranging from 0.0 % in NO2 to 1.6 % in NO5.

These results indicate that the Scandinavian energy system is capable of integrating significant amounts of ZEBs with PV on an aggregated level, also with no local storage within the buildings. However, our study captures only the limitations of the electricity grid between the model regions and does not consider the local grid conditions within each model regions. Nevertheless, there exist technical solutions to the local grid challenges. This is supported by [73] that provides technical solutions for three PV penetration levels; including PV curtailment, voltage adjustment in trafos, local storage and advanced short-term PV forecasting methods.

4.4 Energy system cost

Figure 12 shows the energy system cost for the model cases, relative to the energy system cost of *REF*. The discounted energy system cost is the minimum investment and operational costs, accumulated over the total time-horizon, to meet the Scandinavian energy demand. This includes investments in both supply and demand technologies, expenses related to operation of capacity, fuel costs, income of electricity export and costs of electricity import from countries outside Scandinavia.

The deployment of passive building standard in the model cases *PBU*, *ZEB* and *ZEB**, and the building-integrated PV production in *SUN*, *PBU*, *ZEB* and *ZEB**, are model inputs and their related costs are not reflected in the energy system cost. Thus, the difference between *REF* and *PBU*, of 28 billion EUR, represents the energy system savings due to the reduced heat demand, and the difference between *REF* and *SUN*, of EUR 26 billion, reflects the savings caused by the added PV production. The system saving of ZEBs, is derived by comparing *REF* and *ZEB*, and is EUR 47 billion. Note that this is less than the sum of the cost savings due to passive standard and building integrated PV separately. It is also beneficial for Scandinavia with more variable European electricity prices. This is because the flexible electricity generation in Scandinavia enables electricity export when the prices are high and electricity import when the prices are low. With ZEBs in Europe, that increase the price variability, the energy system cost is reduced with EUR 3 billion when comparing *ZEB* and *ZEB**,

4.5 Benefit of stochastic model approach

The applied stochastic approach gives investment decisions that differ from the corresponding deterministic models, as the stochastic approach base investment decisions on a range of possible realisations of operational situations. The difference in investment decisions in electricity- and heating- technologies between a deterministic and our stochastic approach is evaluated in Appendix B. The main conclusion from this analysis is that a simplified deterministic approach, where the expected values of the uncertain parameters are used as model input, overestimates the competiveness of intermittent electricity generation and underestimates the investments in heat capacity in buildings compared to the stochastic approach.

5 Conclusions

This paper investigates the impact of a large introduction of ZEBs on the Scandinavian energy system towards 2050 with a stochastic TIMES model. When assuming that all new buildings and parts of the rehabilitated buildings are nearly ZEBs, 50 % of the Scandinavian building stock is expected to be nearly ZEBs by 2050. A nearly ZEB is defined to be a passive building with on-site PV production that equals the building's annual electricity specific demand. Further, we assume no use of energy storage within the buildings, and hence the difference between electricity supply and demand of ZEBs is handled by electricity trade.

An implementation of ZEBs affects the cost-optimal investments and operation of the energy system in two ways; through the lower heat demand and the increased PV production. In the electricity sector, the investments in CHP, non-flexible hydropower and wind power is reduced, with a largest impact on the investments in wind capacity. As ZEBs lowers the electricity price throughout

Scandinavia, the wind capacity is reduced with over 50 % in 2050, where most of the reductions occur in Sweden and Norway. Although Norway has favourable wind conditions, the absence of hydropower, with a long lifetime, and the interconnection to Europe, the wind power capacity is highest in Denmark.

In the building sector, where deployment of ZEBs reduces the heat demand by 35 TWh in 2050, the capacities of all types of heating technologies are decreased, but the share of heat supply from electric boilers and direct electric heating increases. Jointly, this gives a marginal decrease in the electricity use in buildings, contributing to a 4 TWh reduction of the Scandinavian electricity consumption in 2050.

The results illustrate that the Scandinavian energy system is well suited to integrate a large amount of ZEBs with PV on an aggregated level due to its flexible hydropower plants. With 63 GW of PV in 2050, the energy system cannot utilise all the non-flexible electricity generation in 3 % of the time, corresponding to 2 % unutilised PV production. Further work should address whether the Scandinavian energy system will benefit from local energy storage within buildings or if curtailing the PV production is more cost-efficient. Although additional energy storage in buildings can increase the trading flexibility to Europe, the existing hydropower plants provides substantial flexibility to the electricity market, and is able to adapt the electricity trade pattern between Scandinavia and Europe with an implementation of ZEBs.

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7 Figures

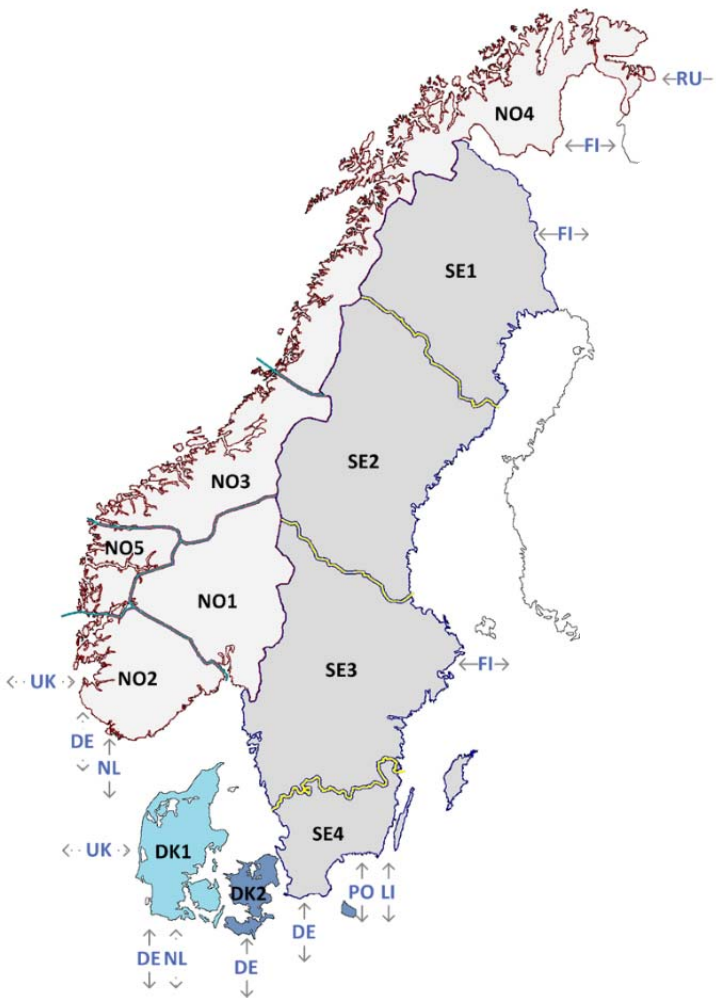


Figure 1: Illustration of the Scandinavian Nord Pool price areas, with indication of existing and proposed transmission capacities to surrounding countries; Finland (FI), Poland (PO), Lithuania (LI), Germany (DE), the Netherlands (NL) and the United Kingdom (UK).

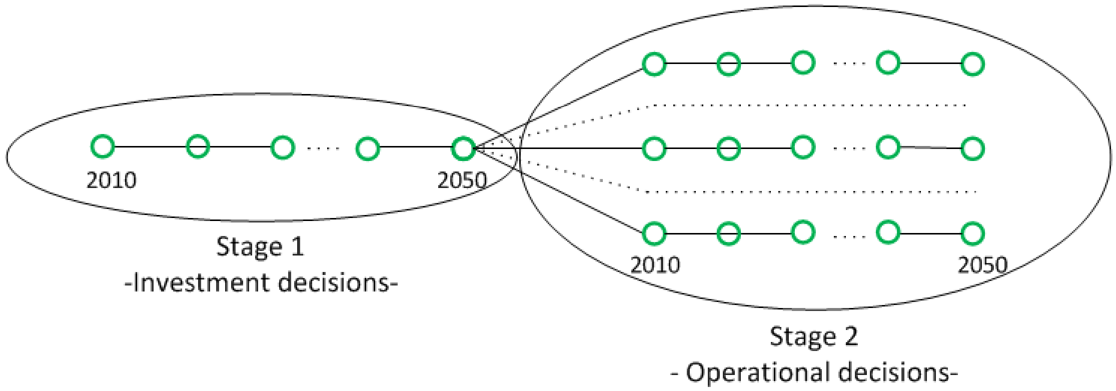


Figure 2: Illustration of the two-stage scenario tree.

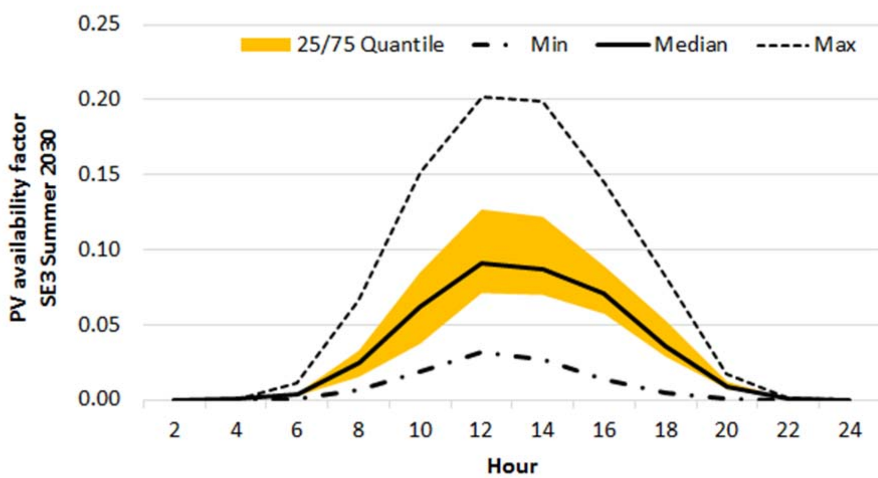


Figure 3: PV scenario characteristics for SE3 Summer 2030; 25/75 Quantile, Minimum, Median and Maximum daily PV availability factor.

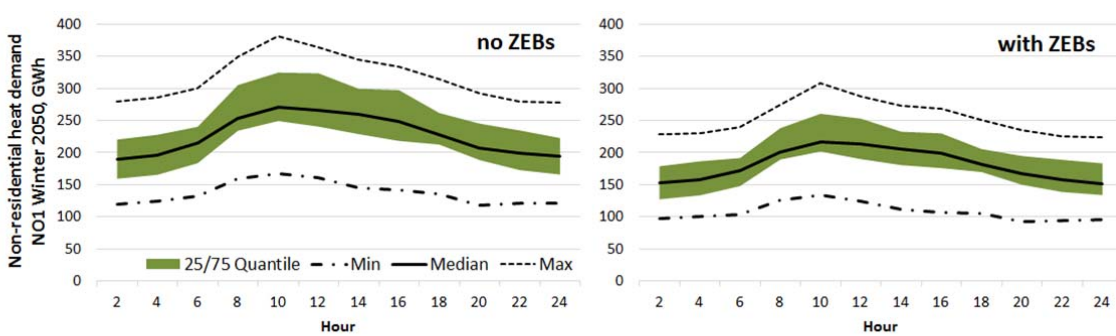


Figure 4: Heat demand scenario characteristics for NO1 Winter 2050; 25/75 Quantile, Minimum, Median and Maximum daily non-residential heat demand, with and without ZEBs.

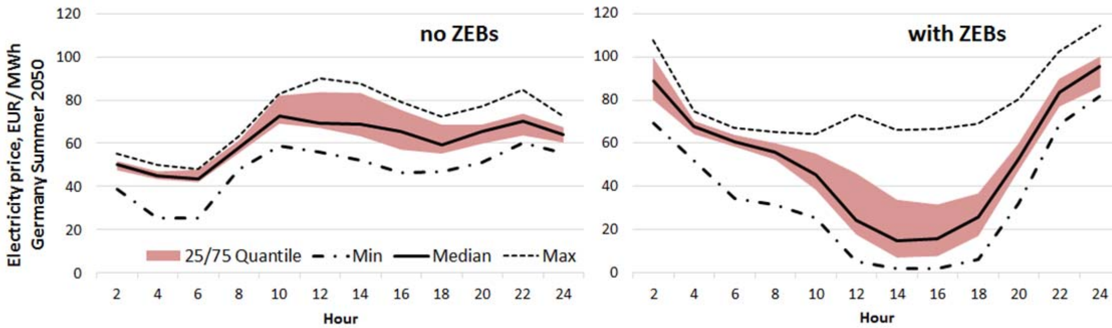
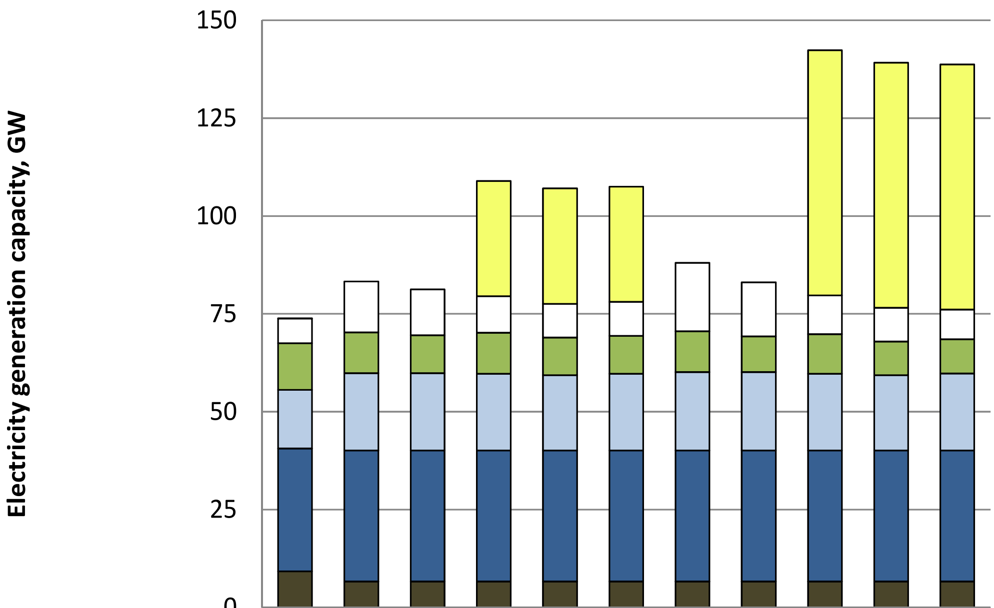
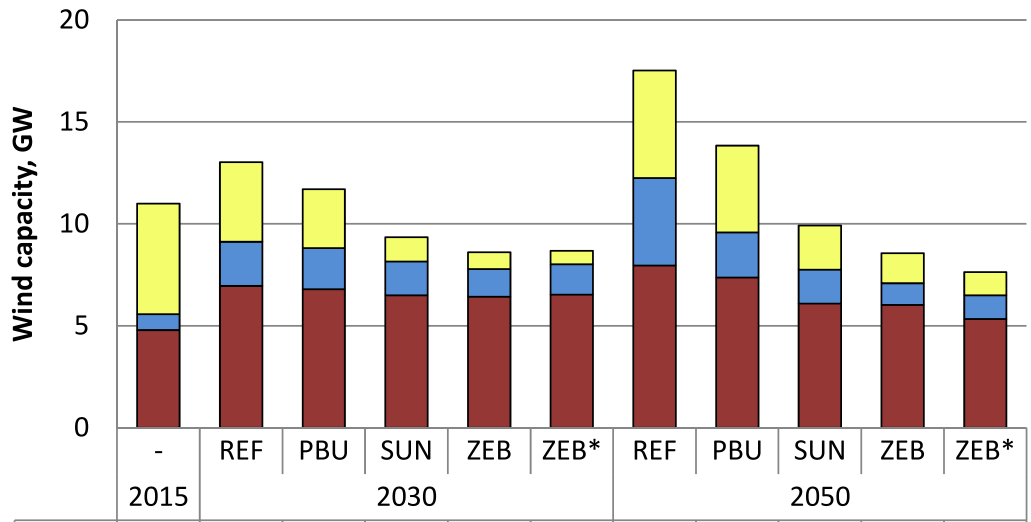


Figure 5: Electricity price scenario characteristics for German Summer 2050, 25/75 Quantile, Minimum, Median and Maximum daily prices, with and without ZEBs.



	2010	2030 REF	2030 PBU	2030 SUN	2030 ZEB	2030 ZEB*	2050 REF	2050 PBU	2050 SUN	2050 ZEB	2050 ZEB*
Total	73.8	83.3	81.3	109.0	107.0	107.5	88.0	83.1	142.3	139.1	138.7
PV	0.0	0.0	0.0	29.4	29.4	29.4	0.0	0.0	62.6	62.6	62.6
Wind	6.3	13.0	11.7	9.3	8.6	8.7	17.5	13.8	9.9	8.6	7.6
CHP	11.9	10.4	9.7	10.4	9.6	9.7	10.4	9.1	10.1	8.6	8.7
Non flexible hydro	15.0	19.8	19.7	19.6	19.2	19.6	20.0	20.0	19.6	19.2	19.7
Flexible hydro	31.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4
Nuclear	9.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7

Figure 6: Installed electric generation capacity in total Scandinavia, by technology, for all model cases in 2010, 2030 and 2050.



	-	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
	2015	2030					2050				
Total	11.0	13.0	11.7	9.3	8.6	8.7	17.5	13.8	9.9	8.6	7.6
SE	5.4	3.9	2.9	1.2	0.8	0.7	5.3	4.3	2.2	1.5	1.139
NO	0.8	2.2	2.0	1.6	1.4	1.5	4.3	2.2	1.7	1.1	1.2
DK	4.8	7.0	6.8	6.5	6.4	6.5	8.0	7.4	6.1	6.0	5.3

Figure 7: Wind power capacity in Denmark, Norway and Sweden for all model cases in 2015, 2030 and 2050.

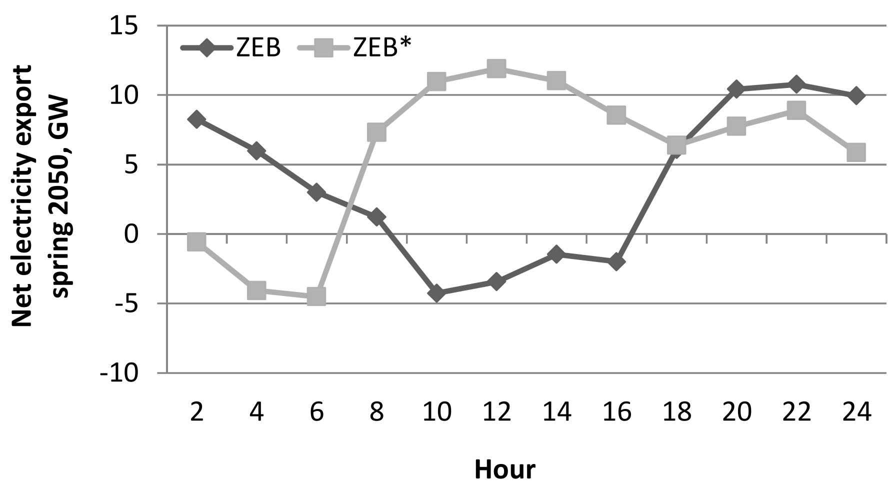
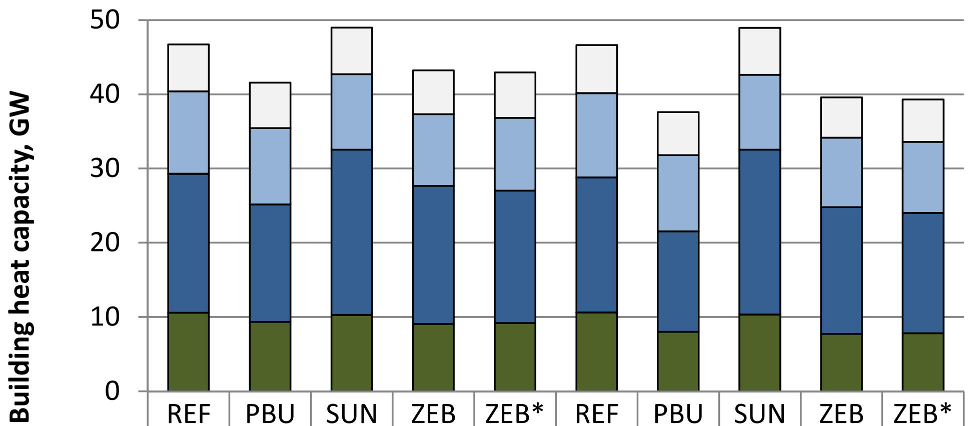
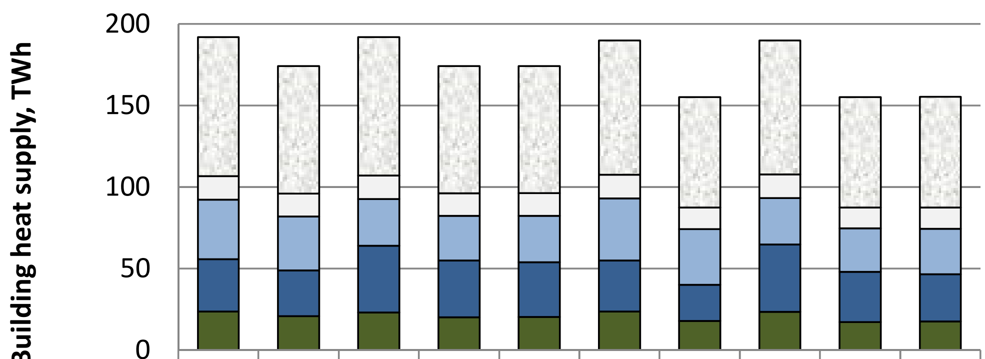


Figure 8: Expected net electricity export from Scandinavia in spring 2050 for ZEB and ZEB*.



	2030					2050				
	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
Total	46.7	41.6	49.0	43.2	42.9	46.6	37.6	48.9	39.6	39.3
Gas	6.3	6.1	6.3	5.9	6.1	6.5	5.8	6.3	5.4	5.7
Heat Pump	11.1	10.3	10.1	9.7	9.8	11.3	10.2	10.1	9.4	9.5
Electricity	18.7	15.8	22.2	18.6	17.9	18.2	13.5	22.2	17.0	16.2
Biomass	10.6	9.4	10.3	9.1	9.2	10.6	8.0	10.4	7.8	7.8

Figure 9: Heat technologies installed in buildings, for all model cases in 2030 and 2050.



	2030					2050				
	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
Total	192	174	192	174	174	190	155	190	155	155
District heat	85	78	85	78	78	82	68	82	68	68
Gas	14	14	14	14	14	15	13	15	13	13
Heat Pump	36	33	28	27	28	38	34	28	27	28
Electricity	32	28	41	35	34	31	22	41	31	29
Biomass	24	21	23	20	20	24	18	23	17	17

Figure 10: Heat supplied to buildings, by technology, for all model cases in 2030 and 2050.

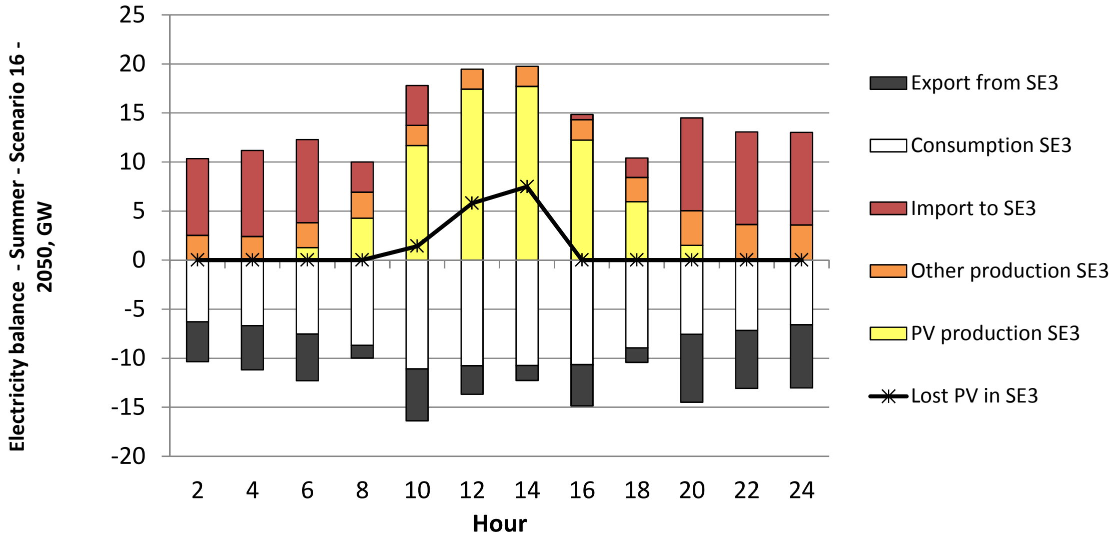


Figure 11: The electricity balance of a random summer day in 2050 for *ZEB* in region SE3.

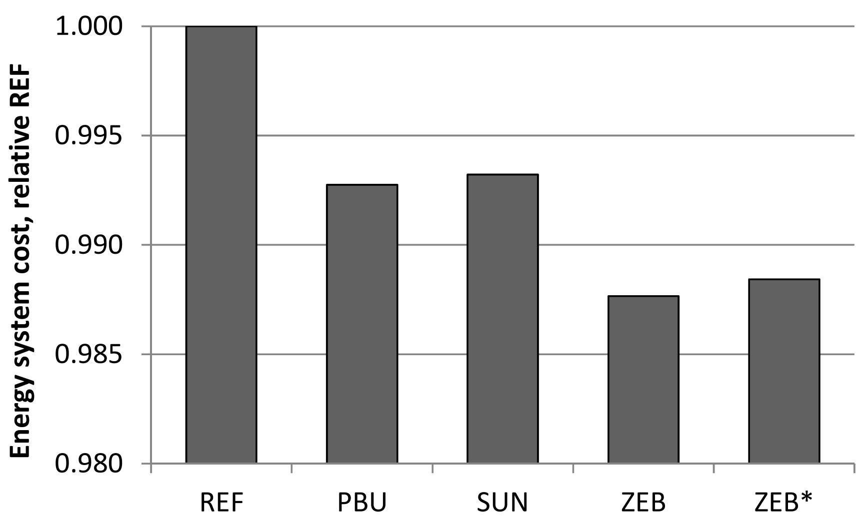


Figure 12: Energy system cost for all model cases, relative to REF.

8 Tables

Table 1: Heat demand in buildings in 2015, 2030 and 2050 dependent on ZEB implementation.

	Minimum/ Average/ Maximum Heat demand, TWh/y				
ZEBs		No		Yes	
Model period	2015	2030	2050	2030	2050
Model case	REF	REF, SUN		PBU, ZEB, ZEB*	
Denmark	49/ **53**/ 61	47/ **51**/ 58	43/ **46**/ 53	43/ **47**/ 53	35/ **38**/ 44
Norway	41/ **45**/ 51	47/ **51**/ 58	51/ **54**/ 63	43/ **47**/ 53	41/ **44**/ 51
Sweden	84/ **92**/ 107	83/ **92**/ 106	85/ **92**/ 108	76/ **84**/ 97	69/ **75**/ 88
Scandinavia	174/ **189**/ 219	177/ **194**/ 222	179/ **192**/ 224	162/ **178**/ 203	145/ **157**/ 183

Table 2: The electric specific demand in buildings, with corresponding on-site PV capacity, for 2015, 2030 and 2050

	Electric specific demand, TWh/y			PV capacity, GW	
Model period	2015	2030	2050	2030	2050
Model case	REF, ZEB, PBU, SUN, ZEB*			ZEB, SUN, ZEB*	
Denmark	19	19	19	4.6	9.2
Norway	30	33	37	9.5	21.2
Sweden	48	48	50	15.3	32.2
Scandinavia	98	100	106	29.4	62.6

Table 3: Main characteristics of the model cases

Case	Passive building standard in Scandinavia	On-site PV production in Scandinavian buildings	ZEB deployment in Europe
REF	**No**	**No**	**No**
ZEB	**Yes**	**Yes**	**Yes**
PBU	**Yes**	**No**	**Yes**
SUN	**No**	**Yes**	**Yes**
ZEB*	**Yes**	**Yes**	**No**

Table 4: National electricity balance in Scandinavia in 2050 for all model cases.

Model case	TWh	Denmark	Norway	Sweden	Scandinavia
REF	**Generation**	37	182	148	367
	Consumption	34	140	145	319
	Net export	1	35	-5	30
	Loss	2	7	8	17
PBU	**Generation**	33	175	143	351
	Consumption	33	135	138	307
	Net export	-2	33	-3	29
	Loss	2	7	7	16
SUN	**Generation**	40	190	162	392
	Consumption	35	147	138	321
	Net export	3	36	7	45
	Loss	2	8	17	27
ZEB	**Generation**	39	186	158	382
	Consumption	34	141	139	315
	Net export	2	38	10	49
	Loss	2	7	9	18
ZEB *	**Generation**	37	188	157	383
	Consumption	33	140	139	313
	Net export	2	41	10	52
	Loss	2	7	8	18

9 Appendix A – Model input on energy prices

Table A1: Model input on energy prices in 2020, 2030, 2040 and 2050

EUR/ MWh	2020	2030	2040	2050
Fossil fuels				
Coal	13	13	14	14
Natural gas	32	35	36	36
Oil	64	69	72	72
Biomass				
Pellets	29 – 44	31 - 46	31 - 47	31 - 47
Straw	24	26	27	27
Chips	22 – 33	24 - 37	25 - 38	25 - 38
Biogas	30 – 46	31 - 47	33 - 49	33 - 49
Electricity				
Germany	56	62	64	64
Lithuania	56	62	64	64
Poland	56	62	64	64
United Kingdom	84	75	72	72
The Netherlands	66	65	65	65
Finland	54	57	58	58

10 Appendix B - The value of a stochastic model approach

This appendix evaluates the difference in investment decisions in electricity and heat capacity of using a deterministic and a stochastic approach. Both approaches have the same model input except for the representation of the uncertain parameters. In the deterministic approach, the expected values of the uncertain parameters are used as model input.

Figure B1 depicts the difference in electricity capacity between a deterministic and a stochastic approach for all cases in 2030 and 2050. For all model cases, the deterministic methodology has higher investments in electricity capacity, with primarily an increase in intermittent electricity generation. In 2050, the increased wind capacity ranges from 1.4 GW for *ZEB** to 2.2 GW for *PBU*, corresponding to 18 % and 12 % higher capacity respectively compared to the stochastic approach. The flexible hydro capacity is indifferent to the representation of the uncertain parameters, whereas the profitability of non-flexible hydro plants is overestimated with a deterministic approach. For *ZEB* in 2050, the investments in new non-flexible capacity is 4.4 GW with a deterministic and 4.3 GW with a stochastic approach. The impact of modelling approach on CHP investments varies with model case, where the CHP capacity is higher for the stochastic approach for most instances.

Further, the results indicate that the deterministic approach underestimates the optimal investments of heating technologies in buildings. Figure B2 illustrates the difference in heat capacity between the deterministic and stochastic approach in 2030 and 2050 for all cases. Here, the heat capacity excludes district heat plants, and the technology group named *Electricity* includes both electric boilers and direct electric heating. For all instances, the deterministic methodology finds it optimal to invest in less capacity in electricity and gas technologies compared to a stochastic approach whereas the influence on HPs and bio fuelled heating depends on case and period. It is especially the installed capacity for direct electric heating that is affected by the representation of the uncertain parameters. For *REF* in 2050, the electricity capacity is 71 % higher for a stochastic compared to a deterministic approach.

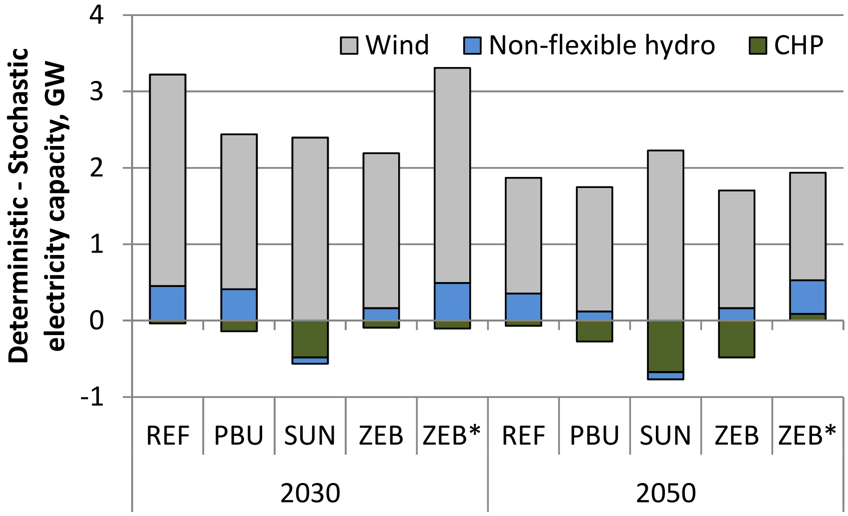


Figure B1: Deterministic minus Stochastic electricity capacity in 2030 and 2050 for all model cases.

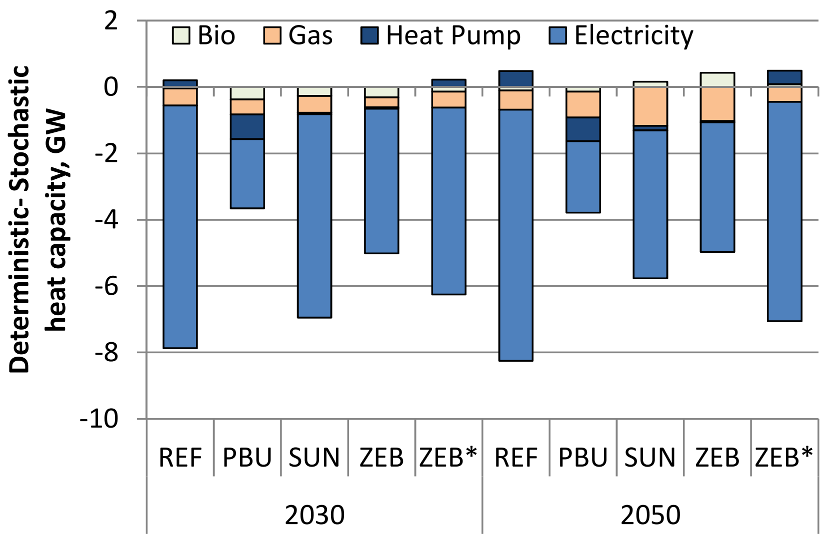


Figure B2: Deterministic minus Stochastic heat capacity in 2030 and 2050 for all model cases.