Optimization of the electricity and heating sectors development in the North Sea region towards 2050

Gea-Bermudez, Juan; Koivisto, Matti Juhani; Münster, Marie

Published in:
Proceedings of the 18th Wind Integration Workshop

Publication date:
2019

Document Version
Publisher's PDF, also known as Version of record

Optimization of the electricity and heating sectors development in the North Sea region towards 2050

Juan Gea-Bermúdez
Department of Sustainability
Technical University of Denmark
Lyngby, Denmark
Email: jgeab@dtu.dk

Matti Koivisto
Department of Wind Energy
Technical University of Denmark
Roskilde, Denmark
Email: mkoi@dtu.dk

Marie Münster
Department of Sustainability
Technical University of Denmark
Lyngby, Denmark
Email: maem@dtu.dk

***Abstract*—Ambitious goals have been established in the EU to decarbonize the energy system towards 2050. This paper investigates the optimal development of the heat and power system of the North Sea region. The optimization of investment, decommissioning and transmission expansion has been performed with the open source energy system model Balmorel. The results show a large deployment of Variable Renewable Energy (VRE), power transmission, Power-To-Heat (P2H), heat storage, and flexible bio fueled Combined Heat and Power (CHP) plants towards 2050. Most of the electricity generation is expected to be provided by wind, solar PV, hydro and nuclear sources (96% by 2045, 63% just wind and solar). On the heating sector, most of the generation is expected to come from bio fuel CHP plants and P2H (68% and 24% by 2045 respectively), especially to satisfy the high temperature demand of industry. P2H increases the power load 10% by 2045. This development, largely influenced by the assumed increase of the CO_2 tax and decrease in VRE costs, leads to a massive reduction of the CO_2 emissions of the system, although not to a complete elimination of them.**

I. Introduction

The EU has set ambitious goals for decarbonization of the energy sectors in Europe [1]. CO_2 prices are expected to increase to support this transition. On the other hand, clean Variable Renewable Energy (VRE) is experiencing rapid costs decrease, making them competitive against traditional fossil fuel sources. This picture suggests that VRE are likely to have an important role in the future energy system. However, the penetration of VRE increases the need for flexibility in the system due to the uncertainty and variability of its nature.

In the North Sea region, a large deployment of wind offshore and its corresponding offshore grid is expected [2]. Transmission development is in direct competition with sector coupling to provide the required flexibility to the system [3]. The possibility of using P2H and heat storage technologies in the heating sector as another source for flexibility for the electricity sector, and at the same time to cover part of the heat demand, is becoming real. Which one should be the capacity development of each technology towards 2050 is an open question, and this paper aims to provide some light on the issue.

In this paper we optimize the generation, transmission, and storage capacity development of the electricity and heating sectors towards 2050 in the countries around the North Sea region. The heating sector studied includes the industry sector, and individual users connected to district heating. The capacity development optimization is performed from a private economic perspective with a level playing field, including only the CO_2 tax. Decommissioning of existing and future generation and storage units based on lifetime expectancy and economic profitability is also part of the optimization. The electrification of the transport sector is not optimized, but its development is taken from the Flex4RES project scenarios [4].

We differentiate from other studies 1) by performing and intertemporal optimization rather than following a myopic approach, like in [3] or [5], to capture the importance of the long-term perspective in investment decision, and 2) by optimizing the offshore and onshore development of the heat and electricity sector together, distinguishing from [5], and including the industry sector, differentiating from [3]. Optimizing both onshore and offshore elements together is important to capture the synergies between the elements, as suggested in [2].

This paper is structured as follows. An introduction to the problem is given in section I. The model and data used in this paper are explained in section II and section III, respectively. A discussion about the paper results and limitations is provided in section V. Finally, the main conclusions are shown in section VI.

II. Model

The modelling is carried out using the Balmorel energy system model [6]. Balmorel is an open source, deterministic model, with a bottom-up approach and is implemented in GAMS. The latest version of the model, i.e. BB4, is used in this paper. The model code can be found in [7].

The time resolution used in this paper is years, which are composed of seasons (in this paper representing weeks), which are composed of hours. The geographical resolution used in this paper is countries, which are divided in regions, which are divided in areas.

The countries included in the optimization are United Kingdom (UK), Norway (NO), Sweden (SE), Finland (FI), Poland (PL), Germany (DE), Denmark (DE), The

Netherlands (NL), Belgium (BE), and France (FR). These countries are split in regions that represent their current electrical bidding zone, except DE, which is split in four regions to model its internal transmission congestion.

The model performs a linear cost minimization by optimizing investments, decommissioning, and energy dispatch in the scenario years 2025, 2035, and 2045, which represent 10-year-periods towards 2050. The optimization is performed with a two-year rolling horizon intertemporal approach. This means that the model performs the capacity development optimization of the scenario years 2025 and 2035 (with perfect foresight of both scenario years), and then does the same for 2035 and 2045 including the optimal development found for the year 2025. Intertemporal discounting is not considered, and hence, all scenario years have the same weight in the objective function. Investment costs are expressed in terms of annuities so technologies with different lifetimes can be compared. A Relaxed Mixed Integer Programming solver is used in the optimization as an approximation to include the Unit Commitment (UC) methodology, which is relevant for thermal plants. The UC elements included are minimum production, start-up and shut-down costs, online costs, ramping limits, and minimum on and off time. Due to the large complexity of the problem, a reduced amount of areas, regions, and conveniently selected time steps are used. The selected time steps used are 1-every-3 hours of Thursday, Friday and Saturday of 14 weeks distributed over the year. Step-wise price functions for bio fuels are used in order to model the increasing cost of bio fuels with its utilization. There are no restrictions on bio fuel exchange between regions.

Two type of storage are included in the model based on their operation behaviour: long and short term. Long-term storage is characterized by a high ratio between energy and discharge capacity, whereas for short-term storage this ratio is assumed to be small. Long-term storage has the constraint that the level at the end of the year must equal the level at the beginning, whereas short-term storage has the constraint that the level at the end of the season (one week) must equal the one at the beginning of it, with no link between seasons. Storage is assumed to have energy losses, and hence, adding net demand to the system. Hydro reservoirs with hydro inflow are a special type of long-term electricity storage included in the model.

Generation investment possibilities include flexible Combined Heat and Power (CHP) and non-CHP power plants (steam turbines, gas turbines, combined cycles, and engines) burning fossil (coal and natural gas) and/or bio fuels (straw, woodpellets, woodchips, and biogas), wind onshore, wind offshore, solar PV, solar heating, heat pumps (air-to-water, and ground-to-water), and heat boilers powered by electricity or the previously mentioned fossil fuels and bio fuels. Back-pressure steam turbine CHP new units are implemented with turbine bypass options to increase their flexibility. The bypassed flow makes these plants capable of operating as if they were heat boilers. Storage technology investments are allowed for hydro pumping (modelled as long-term electricity storage without hydro inflow), electric batteries (short-term electricity storage), and thermal storage (pit storage (long-term heat storage) and water tanks (short-term heat storage)). The use of storage and Power-To-Heat (P2H) is optimized by the model.

Decommissioning of generation and storage technologies is based on commissioning dates, lifetimes and profitability. Hydro power plants are not endogenously decommissioned to reduce the complexity of the problem. A technology will be decommissioned if it is not worth paying the annual fixed costs and/or it has reached the end of its technical lifetime.

Power exchange between regions is allowed and is a function of the corresponding available interconnection capacity between two regions. Electricity transmission investments between relevant regions are allowed.

The heating sector is modeled based on temperature levels. The heat demand of the relevant areas is associated to a particular temperature range. In this model two ranges have been used for the sake of simplicity, i.e. low and high. Low temperature demand areas include the heat demand corresponding to temperatures up to 100 degrees C, whereas high temperature demand areas includes the heat demand with temperatures higher than 100 degrees C. Heat flow is only allowed from high temperature areas to low temperature areas to respect thermodynamics laws, and is a function of the corresponding available heat interconnection capacity between two areas. Heat pumps and heat storage are assumed to be only capable of satisfying low temperature heat demand due to operational constraints. District heating expansion investments between relevant areas are allowed.

The optimization of the energy dispatch of the year 2016 is also performed for validations purposes and so the transition of the energy system can be compared to close-to-today's situation. This independent-from-the-previous optimization is performed including all taxes and tariffs which were removed in the development optimization.

III. Data

The data used in the paper is mostly taken from the Flex4RES project [4] and FutureGas [8]. Some important updates have been performed though. Hereby only the main assumptions and changes are mentioned. The data applied can be found in [9].

As used in [4] and [8], it is assumed a great increase of the carbon tax during the 2020s, and reaching 130 €2012 per tCO_2 by 2050 to push the swift to move away from fossil fuels. This scenario is based on [10]. The fuel price development is also based on [10] and corresponds to its 2 degree scenario.

The conventional electricity demand is assumed constant towards 2050 [4] [8]. The power demand from Electric Vehicle (EV) is assumed non-flexible, i.e. dummy charging, and is based on [11], which assumes that by 2050 around 50% of the total fleet will be EVs.

The heating sector includes the industrial sector and individual consumers assumed to be connected to district heating. The heat load of individual consumers which are not assumed to be connected to district heating is not optimized, although their corresponding electrical load is included and considered non-flexible in the optimization. The demand of individual consumers connected to district heating is assumed to increase slightly due to further penetration of district heating towards 2050 [4] [8]. Industry generation heat capacity and the annual heat demand for different temperature levels is based on [12]. In each region of the model, the industry sector is split into currently connected and non-connected to district heating areas. The heat demand of industry is assumed constant towards 2050. On the other hand, the heat demand time series for industry are taken from [13]. These time series are split in space heating, process heat low temperature, and process heat high temperature. The time series for individual consumers connected to district heating are taken from [4] [8]. District heating expansion investment cost (2.16 M€2012 per MW) is based on the TIMES-DK model [14]. The expansion of district heating to connect non-connected to district heating industrial areas is optimized.

The existing and planned generation and transmission capacities are taken from [4] and [8]. Transmission capacities correspond to Net Transfer Capacities, except for the regions inside DE, which correspond to thermal limits. The generation capacities of UK, FR, BE and NL have been updated from national official reports and European Network of Transmission System Operators (ENTSOE) data [15] [16] [17]. Transmission expansion costs are taken from [4], [8], and [18]. Transmission line availability is assumed to be 95% [4]. Generation availability time series are also taken from [4].

Most of the generation and storage technology data (costs, efficiencies, etc.) is based on the latest technology catalogue of the Danish Energy Agency [19]. Particularly, unit commitment related data is based on [19], [20], and [21]. The assumption on the linear technology costs (M€2012 per MW) depends on each area type so economies of scale can be reflected. For example, it is assumed that in industrial areas only small-scale technologies are allowed for investments, and hence, their linear cost is higher than in areas where large-scale technologies are allowed, like for example large district heating areas. The source [19] assumes a considerable decrease in costs towards 2050 for wind onshore (1.15 M€2012 per MW in 2020 and 0.97 M€2012 per MW in 2050), Solar PV (0.6 M€2012 per MW peak in 2020 and 0.4 M€2012 per MW peak in 2050), and wind offshore turbines. Compensation costs (social acceptance) are included for wind onshore. Wind offshore data has been further updated and combined with data from the project-based scenario of the NSON-DK project [18]. This technology is split into three types (near-shore AC-connected, far-offshore AC-connected, and far-offshore DC-connected), each of them with their corresponding grid connection costs, turbine costs, Capacity Factors (CF) and time series depending on the location. For example, excluding the grid connection costs, the far-offshore wind turbines cost are assumed to decrease from 1.7 M€2012 per MW in 2020 to 1.4 M€2012 per MW in 2050. Since the scenario years 2025, 2035, and 2045 are optimized, the costs corresponding to the years 2020, 2030, and 2040 respectively are used. The 2040 data corresponds to the average of 2030 and 2050 in [19].

Wind onshore and solar PV data of each region is split in at least two resource grades areas with different potentials and CFs. This is done to model that the resource quality is not the same in all areas of the region. These potentials are based on [4] [8]. The CFs of wind onshore and solar PV of the different resource grades areas are based on [22] and [23] respectively. Overall, CFs of wind and solar PV technologies are assumed to increase in the future based on higher hubs (for wind) and improved efficiency (for solar PV). In each of the regions, the time series of the different resource grade areas of wind onshore, and also for solar PV, are assumed identical due to lack of data. These time series are however linearly scaled to match the CF assumptions.

DTU Wind Energy's CorRES tool is used to simulate the wind and solar PV generation time series used in the optimizations performed in Balmorel. CorRES models the varying CFs depending on installation locations, and the spatiotemporal dependencies in VRE generation. Especially offshore wind is modelled in detail, starting from the planned locations of individual Offshore Wind Power Plants (OWPP). More information about the tool can be found in [24] [25].

The aggregated bio fuel potential and its corresponding price in the countries in focus, which is updated and based on [4] and [8], can be seen in table I. The price split and its corresponding share of the total potential is the same in all countries and fuels, except for wood chips, whose price was assumed the same in all the countries except in PO. Bio fuels are assumed not to emit CO_2.

The data for the time series correspond to the year 2012, except for hydro inflow which are based on the average of several years, thereby representing a normal year.

IV. Results

This section contains the results obtained from the energy system optimizations for the analysed countries.

A. Validation of the model

The net electricity generation per source type in 2016 is depicted in figure 1 to compare historic results with model results for the sake of validation. Historical data is obtained from [26]. The comparison shows that, although

Table I
AGGREGATED BIO FUEL POTENTIALS AND ITS CORRESPONDING PRICE

Fuel	Price (€2012/GJ)	Potential (PJ)
Biogas	9.5	11
	16.5	313
	142.3	824
Straw	3.5	54
	6.0	1494
	51.9	3928
Wood chips	3.7	68
	4.1	560
	6.4	1871
	7.1	15420
	55.0	4919
	61.0	40546
Wood pellets	5.8	101
	10.1	2769
	87.1	7280

not perfect, the model provides results close to reality. The contribution of nuclear and the reduced generation in FR and DE seem to be the major differences. The differences can be due to numerous factors, e.g. not using the time series and availability factors corresponding to the year 2016, using a Relaxed Mixed Integer Programming solver instead of pure Mixed Integer Programming, not including all the surrounding countries, including a simplified version of taxes, subsidies and tariffs, etc.

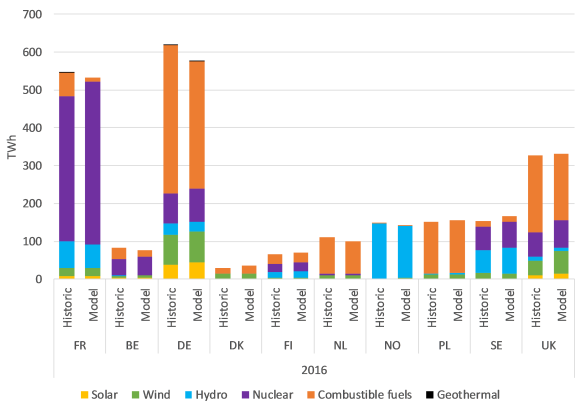

Figure 1. Net electricity generation per source type in 2016 (TWh). Model results versus historical data from [26].

B. Capacity development

1) Generation development: The aggregated electricity, and heat, generation capacity development towards 2050 per technology type is depicted in figure 2 and 3, respectively. In the figures, thermal refers to condensing power plants, i.e. those producing electricity. The replacement of fossil fuels with cleaner energy sources is remarkable. From 2035 on, the penetration of VRE in the power sector, and the penetration of bio fuels, P2H and both short and long term storage in the heating sector, is of great importance. Boilers and only-power plants tend to be replaced with flexible CHP towards 2045. On the other hand, nuclear power decreases towards 2045, although it does not disappear. Nevertheless, by 2045 there is still some fossil fuel based capacity in the system. The total power generation capacity increase towards 2050 is linked to the variability of VRE production. The total heat capacity decrease with respect to 2016 is most likely related to area aggregation, whereas the increase in capacity from 2016 to 2035 can be linked to the penetration of P2H, since P2H is mainly used when electricity prices are low.

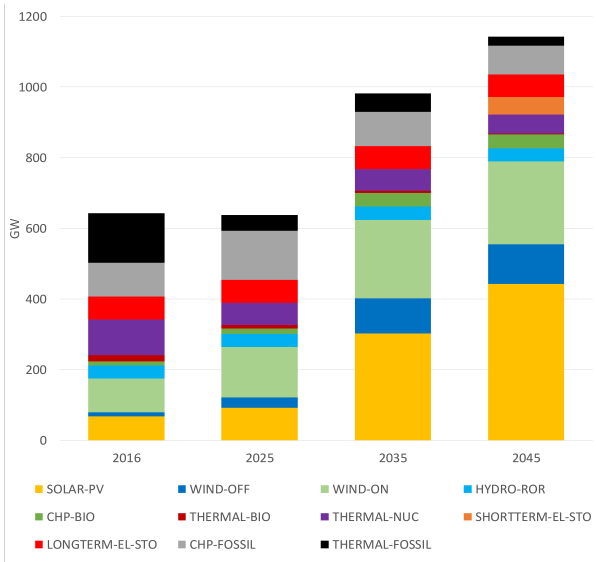

Figure 2. Electricity generation capacity development towards 2050 per technology type (GW). Long-term electricity storage represents hydro reservoirs.

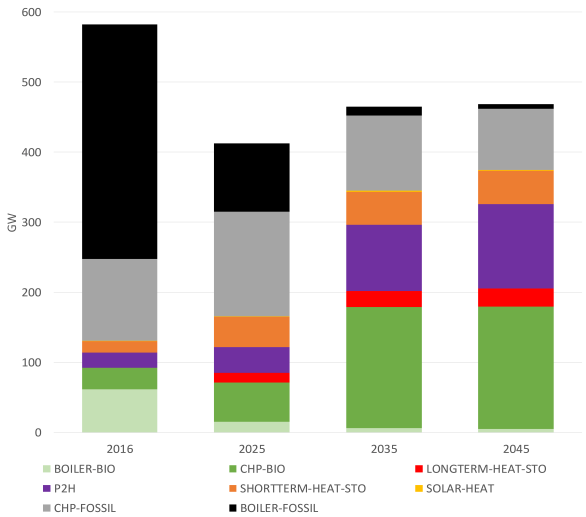

Figure 3. Heat generation capacity development towards 2050 per technology type (GW). It includes the industry sector, and individual users connected to district heating.

The wind and solar development per country is shown in figure 4. The results show that wind onshore is the preferred source of electricity by 2025, reaching the potential of the best resource grade areas in most of the countries by 2035. On the other hand, wind offshore capacity develops gradually towards 2045 in most of the countries, with a great increase by 2035. The countries surrounding the North

Sea are the ones where wind offshore seems to be most attractive. Solar PV develops also gradually towards 2045, except that the countries with highest development are the ones with best resource, i.e. the southern ones. The first resource grade areas of solar PV of many countries reach their potential by 2035. It is interesting to see that in DE by 2035 it is found optimal to replace decommissioned wind onshore with wind offshore and solar PV. This is probably linked to cost development and CFs assumptions. Additionally, it is worth mentioning that in most of the countries the full potential of these sources (the sum of the potential in all the resource grade areas) is not reached.

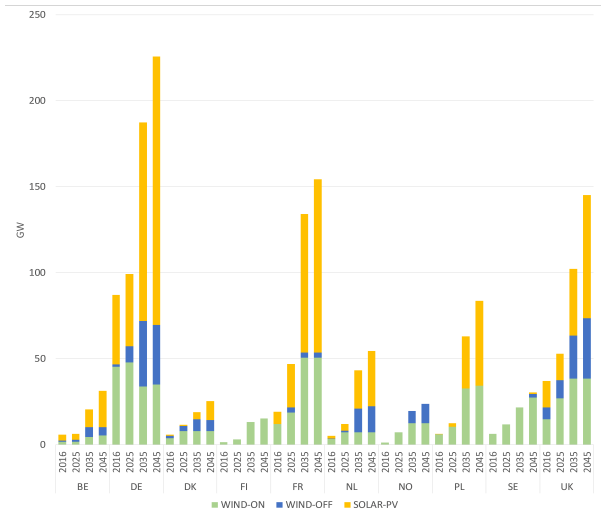

Figure 4. Wind and solar PV capacity development towards 2050 (GW).

2) Storage development: The aggregated short and long term electricity and heat storage development towards 2050 is depicted in figure 5. Long-term electricity storage (hydro reservoirs) is linked to the right vertical axis, whereas the other are linked to the left vertical axis. The results show a great development of both short and long-term heat storage and almost non-existent of electricity storage. Long-term heat storage most likely profits from the seasonal variability of VRE, whereas short-term heat storage is used to provide further flexibility to CHP plants and to profif from daily patterns. Only by 2045 investments in electricity batteries are found optimal. These results suggests that it seems more cost efficient to provide new flexibility to the system via heat storage than electricity storage.

3) Demand development: The aggregated electricity, and heat, demand development towards 2050 per type is depicted in figure 6 and 7, respectively. The pictures show flexible (optimized) demand, i.e. P2H and storage losses, and non-flexible (non-optimized) demand like traditional demand or EV. Traditional demand includes distribution losses. The results show that the non-flexible traditional demand has the biggest share in all the studied years in both sectors. P2H demand increases gradually towards 2050, reaching 10% of the total load. The storage losses are very small in both sectors, and increase slightly towards 2050, especially for the short-term heat storage.

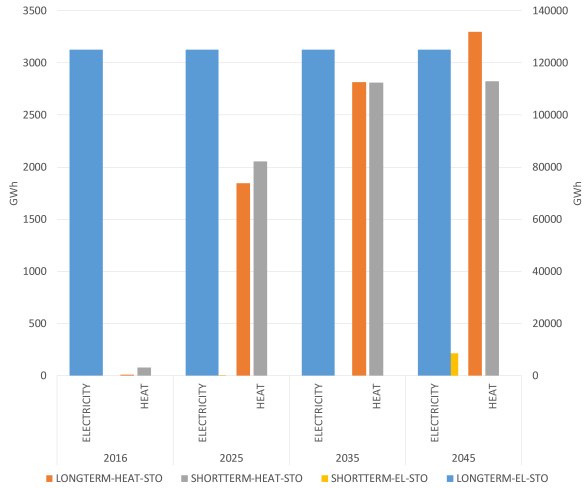

Figure 5. Storage capacity development towards 2050 per technology type (GWh). Long-term electricity storage (hydro reservoirs) is linked to the right vertical axis, whereas the others are linked to the left vertical axis.

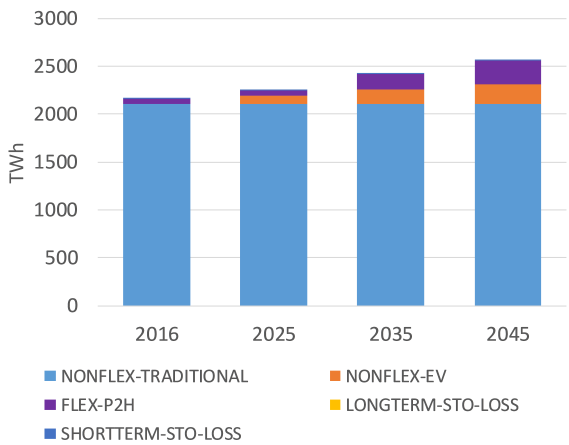

Figure 6. Electricity demand development towards 2050 (TWh).

4) Transmission development: The aggregated electricity transmission capacity development towards 2050 between the regions included in the optimization is depicted in figure 8, and the heat transmission capacity development between the areas in the model can be seen in figure 9. The power transmission development shows a considerable increase of transmission by 2035 and 2045, with the latter reaching around 36% of total capacity by 2045. This expansion is linked to the penetration of VRE in the system. The connections DE-FR and NO-UK are the ones experiencing the highest endogenous transmission expansion, adding 6.5 GW and 3.8 GW respectively to the assumed existing capacities, reaching a total interconnection capacity of 8.7 GW and 5.2 GW by 2045, respectively. On the other hand, district heating expansion of industrial areas is found to be modest, and it does not occur until 2035.

C. System operation development

1) Electricity and heat production development: The aggregated production development of electricity, and heat,

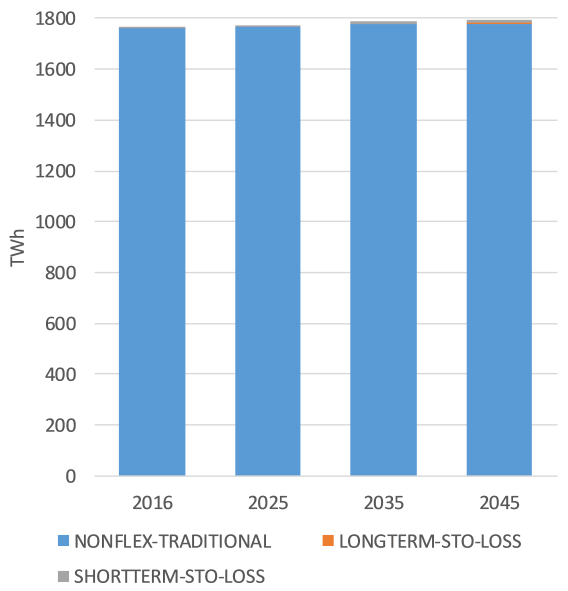

Figure 7. Heat demand development towards 2050 (TWh). It includes the industry sector, and individual users connected to district heating.

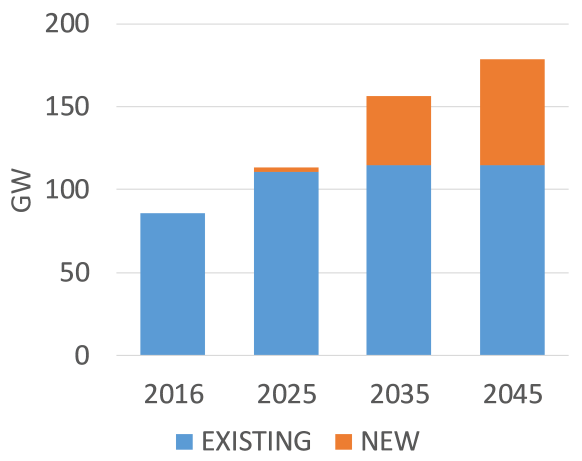

Figure 8. Aggregated power transmission capacity development towards 2050 (GW).

towards 2050 per technology type is depicted in figure 10 and 11, respectively. The development is linked to the capacity development, although for the case of VRE the impact of the different CFs can be clearly seen. For example, even though the solar PV capacity is very high by 2045, it has almost the same share in the electricity production as wind offshore, whose capacity is around 1/4 of the solar PV capacity. Both sectors show a massive decarbonization towards 2045. The increase in 2035 with respect to 2025 is remarkable. The limited bio fuels is mainly used in flexible CHP plants to satisfy the demand of the heating sector (68% of the total heat generation by 2045), especially to cover the high temperature demand of industries, whereas most of the electricity is produced with VRE, hydro and nuclear (96% by 2045). The share of wind and solar in the electricity production is 14%, 23%, 54%, and 63%, in 2016, 2025, 2035, and 2045, respectively. P2H represents around 24% by 2045 of the total heat generation.

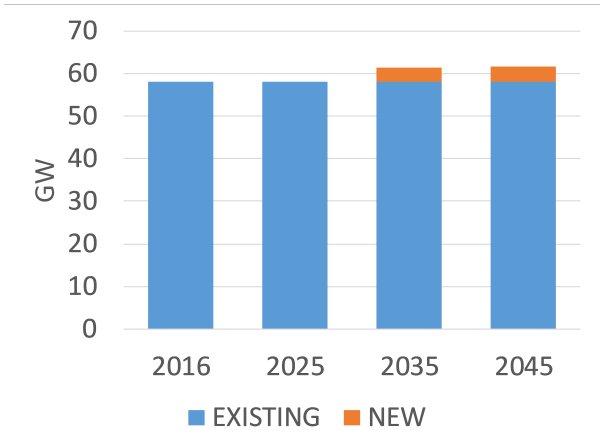

Figure 9. Aggregated heat transmission capacity development towards 2050 (GW). It includes the industry sector, and individual users connected to district heating.

The share of fossil fuel production in the electricity, and heat, sectors by 2045 is 4% and 6%, respectively.

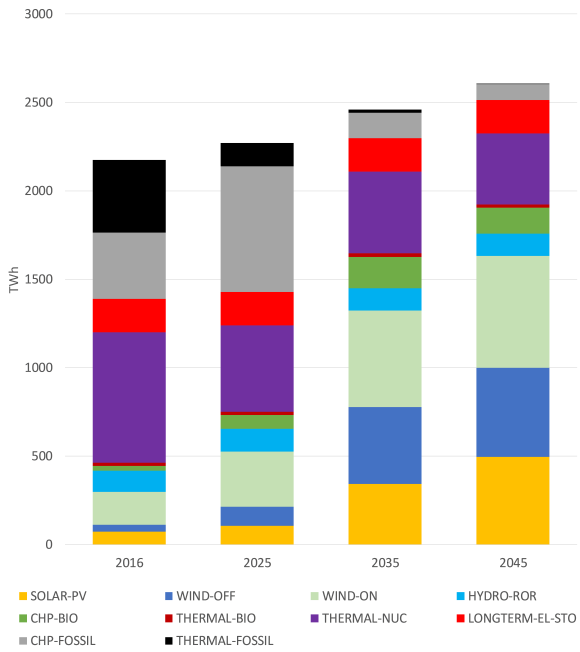

Figure 10. Aggregated electricity production development towards 2050 per technology type (TWh). Long-term electricity storage represents hydro reservoirs.

2) Fuel consumption and CO_2 emissions development: The aggregated fuel consumption development towards 2050, and the associated CO_2 emissions are depicted in figure 12 and 13, respectively. The results show a huge decrease of the utilization of fossil fuels towards 2045, remaining only around 100 TWh of natural gas use by 2045, and an increase of bio fuels to replace a large share of their use. Consequently, the CO_2 emissions decrease massively towards 2045. The decrease from 2025 to 2035 is especially high, and is linked to the previous results. These results suggest that even though the CO_2 price was assumed to increase drastically towards 2050, it does not

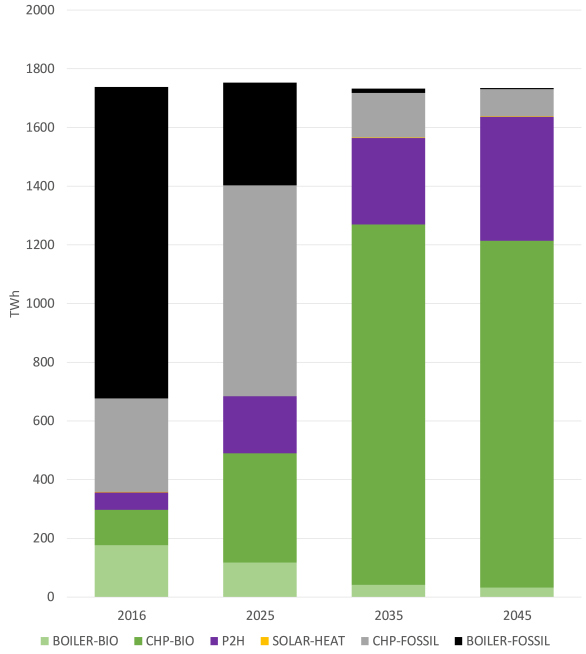

Figure 11. Aggregated heat production development towards 2050 per technology type (TWh). It includes the industry sector, and individual users connected to district heating.

seem enough to achieve a full decarbonization.

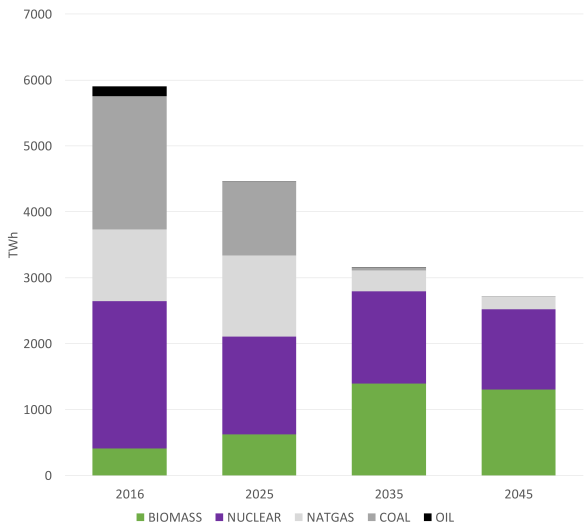

Figure 12. Aggregated fuel consumption development towards 2050 (TWh).

V. Discussion

Although the results of this paper are found to be coherent, they are largely influenced by the model and data assumptions. Even though a large set of potential flexibility and demand were considered, due to computational complexity some of them were not included in the optimization. Example of these are Power To Gas (P2G), individual heating not connected to district heating, energy efficiency, demand response, or EV flexibility. These sources may have reduced, or increase, the utilization

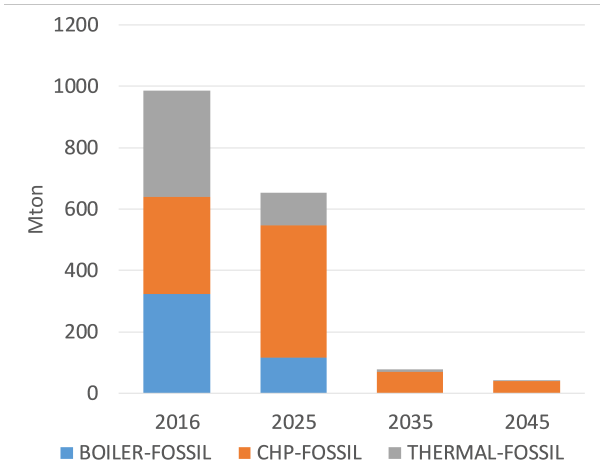

Figure 13. Aggregated CO_2 emissions development towards 2050 (Mtons). Thermal-fossil corresponds to the emissions coming from power-only plants.

of fossil fuels, and therefore, influencing the emissions. Additionally, the spatial and time aggregation, applied to reduce the complexity of the problem, have influenced the results obtained probably leading to underestimating thermal capacity and short-term heat storage, as well as their utilization.

The results show that bio fueled flexible CHP are likely to have a very important role in the future heat sector, especially to provide for the high temperature needs of industry. This result is not found in other studies, like [4] or [3], since neither the industry sector nor the possibility to bypass the turbine in CHP power plant were included. In [3], P2H was the preferred option to provide for low temperature heat. Nevertheless, further analysis on the feasibility of the capacity development and hourly operation of these plants is required. On the electrical side, the results are in line with [4].

The resource grade split used in this paper for wind offshore, wind onshore, and solar PV is found efficient, and the results coherent. However, the data can be further improved, especially regarding potentials and time series.

Even though conservative step-wise costs were used to model the bio fuel resources, the feasibility of the vast utilization of bio fuels should be further studied, since it is much affected by seasonal availability and transport costs. Additionally, the use of the bio fuels potentials for the electricity and heat sectors might be in competition with possible future decarbonization of the transport sector. Furthermore, it was assumed that bio fuels are CO_2 free, which does not necessarily need to be the case when the full chain is considered.

VI. Conclusion

This paper investigates the optimal development of the heat and power energy system of the North Sea region towards 2050. The optimization of investment,

decommissioning and transmission expansion has been performed with the energy system model Balmorel.

The results show a large deployment of VRE, power transmission, P2H, heat storage, and flexible bio fueled CHP towards 2050. This deployment is especially important by the scenario year 2035. Towards 2050, most of the electricity load is likely to be covered with VRE, hydro and nuclear (96% by 2045). Just the share of wind and solar in the electricity production is 14%, 23%, 54%, and 63%, in 2016, 2025, 2035, and 2045, respectively. On the heating sector, most of the load is likely to be covered with bio fueled CHP plants and P2H (68% and 24% by 2045 respectively), especially to satisfy the high temperature demand of industry. P2H increases the power load 10% by 2045. This development, largely influenced by the assumed increase of the CO_2 tax and decrease in VRE costs, leads to a massive reduction of the CO_2 emissions of the system, although not to a complete elimination of them.

Acknowledgment

This paper is a part of NSON-DK and Flex4RES projects funded by the Danish Energy Agency, EUDP (grant 64018-0032; previously ForskEL) and Nordic Energy Research (grant 76084), respectively. Matti Koivisto acknowledges support from the PSfuture project (La Cour Fellowship, DTU Wind Energy). The authors also acknowledge the contributions from Frauke Wiese and Mattia Baldini.

References

[1] European commission, (2018). Available at https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union (accessed Apr 2018)

[2] J. G. Dedecca and R. A. Hakvoort, (2016). "A review of the North Seas offshore grid modeling: Current and future research". Renewable and Sustainable Energy Reviews, vol 60, pp. 129-143. Available at https://doi.org/10.1016/j.rser.2016.01.112

[3] T. Brown, D. Schlachtberger, A. Kies, S. Schramm, M. Greiner, (2018). "Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system". Energy, vol 160, pp. 720-739. Available at https://doi.org/10.1016/j.energy.2018.06.222

[4] Flexible Nordic Energy Systems summary report. Flex4RES project. Available at https://www.nordicenergy.org/wp-content/uploads/2019/07/Flex4RES_final_summary_report_aug2019.pdf

[5] J. G. Dedecca et al., (2018). "Expansion planning of the North Sea offshore grid: Simulation of integrated governance constraints", Energy Economics, vol 72, pp. 376-392. Available at https://doi.org/10.1016/j.eneco.2018.04.037

[6] F. Wiese et al., (2018). "Balmorel open source energy system model." Energy Strategy Reviews, vol 20, pp. 26-34. Available at https://doi.org/10.1016/j.esr.2018.01.003

[7] Balmorel model. Github. Available at https://github.com/balmorelcommunity/Balmorel

[8] P. E. Morthorst, M. Münster, T. Amirkhizi, R. Bramstoft, (2017). FutureGas – The integration of gas in the future Danish energy system. International Gas Union Research Conference 2017.

[9] Balmorel data. Github. Available at https://github.com/balmorelcommunity/Balmorel_data

[10] Nordic Energy Technology Perspectives 2016 report. Available at http://www.nordicenergy.org/project/nordic-energytechnology-perspectives/

[11] P.A. Gunkel, F.J. Fausto, K.Skytte, C.Bergaentzlé, The Impact of EV Charging Schemes on the Nordic Energy System, in the 2019 16th International Conference on the European Energy Market(EEM). IEEEXplore.

[12] Rehfeldt, M., Fleiter, T. Toro, F. Energy Efficiency (2018) 11: 1057. Available at https://doi.org/10.1007/s12053-017-9571-y

[13] F. Wiese, M. Baldini, (2018). Journal of Cleaner Production Conceptual model of the industry sector in an energy system model: A case study for Denmark. Journal of Cleaner Production, Vol. 203, pp. 427-443. Available at https://doi.org/10.1016/j.jclepro.2018.08.229

[14] O. Balyk, et al. (2019). TIMES-DK: Technology-rich multi-sectoral optimisation model of the Danish energy system. Energy Strategy Reviews. Vol. 23, pp. 13-22. Available at https://doi.org/10.1016/j.esr.2018.11.003

[15] ENTSOE data plattform. Available at https://transparency.entsoe.eu

[16] Digest of UK Energy Statistics (DUKES): electricity. Available at https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

[17] Réseau de Transport d'Électricité (RTE) France. Available at https://www.rte-france.com/

[18] M. Koivisto, J. Gea-Bermúdez, (2018), "NSON-DK energy system scenarios – Edition 2", DTU Wind Energy, available at: http://orbit.dtu.dk/files/160234729/NSON_DK_WP2_D2.1.Ed2_FINAL.pdf (accessed Nov 2018).

[19] Danish Energy Agency, Technology Catalogue. Available at https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-generation-electricity-and

[20] N. Kumar, P. Besuner, S. Lefton, D. Agan, D. Hilleman Plant, (2012). Power Plant Cycling Costs. NREL Technical Monitor. Available at https://www.nrel.gov/docs/fy12osti/55433.pdf

[21] K. Van der Bergh, E. Delarue, (2015). Cycling of conventional power plants: technical limits and actual costs. TME working paper - Energy and Environment. Available at https://core.ac.uk/download/pdf/34627483.pdf

[22] Global Wind Atlas. Available at https://globalwindatlas.info/

[23] Global Solar Atlas. Available at https://globalsolaratlas.info/

[24] M. Koivisto, K. Das, F. Guo, P. Sørensen, E. Nuño, N. Cutululis, P. Maule, "Using time series simulation tool for assessing the effects of variable renewable energy generation on power and energy systems", WIREs Energy and Environment, vol. 8, no. 3, e329, May/June 2019. Available at https://doi.org/10.1002/wene.329

[25] W. Skamarock, J. Klemp, J. Dudhia, D. Gill, D. Barker, M. Duda, X. Huang, W. Wang and J. Powers, "Description of the advanced research WRF version 3," Boulder, Colorado, USA, 2008.

[26] Eurostat. Gross and net production of electricity and derived heat by type of plant and operator. Available at https://ec.europa.eu/eurostat/web/energy/data/database