Planning of Distributed Energy Supply to Suburb

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***Abstract*—In this paper, a novel model to optimize the design of local energy networks with respect to operation and investment cost and environmental consequences is demonstrated. The chosen case study is based on a real case from a Norwegian municipality. Several alternatives to supply energy to a new suburb with detached houses are considered: Electrical boilers, ground source heat pumps, gas boilers and a simplified demonstration alternative of hydrogen fuel cell based on renewable energy. The alternatives are ranked with respect to operational and investment cost. Emissions from each alternative are also accounted for. Due to an integrated optimization of diurnal operation and investments, each design alternative can be inspected in the full-graphical user interface to verify the utilization of individual components during peak load and low load periods.**

***Keywords*-- Planning, optimization, renewable energy, heat pumps, hydrogen**

I. INTRODUCTION

New emerging technologies like small-scale co-generation, gas engines and fuel cells enable increasing flexibility in energy supply systems. This will yield new alternatives and better possibilities to design optimal and sustainable energy systems, but these technologies will also result in more complex challenges related to design, operation and maintenance as they introduce physical connections between traditionally separate supply sectors.

The need for energy planning is not reduced with the ongoing liberalization of the energy industry. E.g. a planner in an integrated energy company will have to consider both complementary solutions within his own company and competition from other suppliers that may enter his traditional supply area in a liberalized market environment. This situation has created a need for new improved methodologies and tools for system planning and operation that include multiple energy carriers and sufficient topological details.

In view of these challenges, a novel model named *'eTransport'* which optimizes the design of local energy networks is under development. In this paper, the model is demonstrated through the analysis of an energy supply system in a typical municipality in Norway. The main purpose of the paper is to show how the model is used on a real planning case, not to document the model itself in detail.

In the chosen case study, a new suburb is planned with 2-300 detached houses built over a 30-year period. The planners have a choice between electrical boilers, ground source heat pumps, gas boilers, and more exotic, a hydrogen fuel cell supplied by renewable energy. It is not possible to present the complete analysis with every aspect of the municipal project in this paper. Thus, a number of details from the original study are omitted for simplicity.

The paper is organized as follows: Section II gives a brief motivation and overview of the eTransport model, Section III presents the case study alternatives and Section IV presents case study results. Discussion and Conclusions are found in Sections V and VI, respectively.

II. THE ETRANSPORT MODEL

The area of optimal expansion planning in energy systems with multiple energy carriers is dominated by large scale optimisation tools for regional or global system studies like MARKAL/TIMES, EFOM, MESSAGE and similar models [1-5]. In such large scale energy system studies, the energy system is typically represented with an aggregated type of modelling with one energy balance per energy carrier, and with resources deployed on one side and end use extracted on the other side. Various technologies are modelled with emissions and energy losses. This approach is usually sufficient for system studies on a national or international level. In an improved optimisation approach for expansion planning in local energy supply systems, however, different infrastructures within the geographical area of concern have to be identified. Geography, topology and timing are all key elements in this approach. It is thus not only a question of which resources and which amounts to use, but also where in the system the necessary investments should take place and when they should be carried out.

In international literature several approaches have appeared the last years that integrate two or more energy infrastructures in the analysis. Many of these focus on the integrated operation of gas (fuel) and electricity networks for optimal dispatch of units and/or pricing of transmission capacity [6-10] or downstream optimization of electricity and heat demand from cogeneration [11-12]. Some papers attack the optimization of multiple energy carriers more generalised, incorporating electricity, gas, heat and hydrogen on the supply side as well as electricity, heating and cooling on the demand side [13-16]. The German model DEECO (Dynamic Energy Emission and Cost Optimization) is developed to optimise the rational use of energy and utilization of renewable energy in local energy systems [17-19]. None of these approaches, however, consider the issue of expansion/investment planning of such multiple infrastructures.

Thus, the novel expansion planning model "*eTransport*" is developed for local energy supply systems where

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investments in different energy technologies and carriers are considered simultaneously [20-22]. The model gives the user an overview of a given energy system with respect to costs, environmental consequences and use of local energy resources. The model uses a detailed representation of technologies and infrastructure to enable identification of single components, cables or pipelines. The current version can optimize the expansion of infrastructure for most relevant energy carriers and conversion between these. It is not limited to continuous transport like lines, cables and pipelines, but can also include discrete transport by ship, road or rail. The library modules for hydrogen technologies are still under development, and only simplified versions will be demonstrated in this paper.

The main task of the model is to optimize investments in infrastructure over a planning horizon of 10 to 30 years to bring energy to the end user in such quantities and in such forms that the end users' demands are satisfied in the economically and environmentally best way possible.

The model is separated into an operational model (energy system model) and an investment model; see Fig. 1 [22]. In the operational model there are component libraries with sub-models for each energy carrier and for conversion components. The operational planning horizon is relatively short (1-3 days) with a typical time-step of one hour. The model finds the cost-minimising diurnal operation for a given infrastructure and for given energy loads.

A time-step of one hour is not feasible for investment analysis where the planning period can be 20-30 years. Therefore, the operational analysis is separated from the investment analysis, and annual operating costs for different energy system designs are pre-calculated by solving the operational model repeatedly for different seasons (e.g. peak load, low load, intermediate etc), periods (e.g. 5 year intervals) and relevant system designs. Annual operating and environmental costs for different periods and energy system designs are sent to the investment model that finds the investment plan that minimises the present value of all costs over the planning horizon. Mathematically, the model uses a combination of linear programming (LP) and mixed integer programming (MIP) for the operational model, and dynamic programming (DP) for the investment model as indicated in Fig. 1.

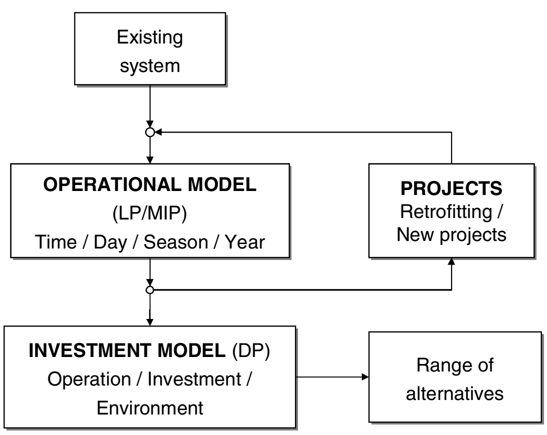

Fig. 1 Integration of operation and expansion planning of energy systems

The operational model (LP/MIP) is implemented in the AMPL programming language with CPLEX as solver. The investment model (DP) is implemented in C++. A modular design ensures that new modules developed in AMPL for the operational model are automatically included in the investment model. A full-graphical Windows interface is also developed for the model in MS Visio (see Fig. 8.). All data for a given case are stored in an Access database.

III. Case Study

A. Case Background

A typical municipality in Norway is characterised by high electricity consumption for space heating purposes, but relatively low energy density. Very little gas is currently used for domestic consumption in Norway.

In this paper, a new development area in the municipality of Florø is chosen as case study [23]. Florø is situated on the Atlantic coast of Norway with a population of 11,410 (2006). Mean annual temperature is +7.1°C, and average precipitation is 1985 mm/year. Total energy consumption in 2004 was 255.4 GWh, of which 69.5% was electricity, 13% kerosene, 10% natural gas and 7.5% biomass. 92.8 GWh were used by private households, of which 78% were electricity. The area of analysis is limited to the development area outside the main city where 2-300 detached homes are expected to be built over the next 30 years. In this paper, the supply of energy to the rest of the municipality, including industrial gas demand, is omitted to emphasize operational and investment costs directly related to the new area.

The period of analysis is set to 25 years (2008-2032), split into 5 year periods. Each year is further split into 3 load segments: Peak load (29 days), Intermediate load (243 days) and Low load (93 days). The construction of new houses is assumed to happen at an even rate of 50 per 5 years, starting in 2013. Fig. 2 shows the development of the diurnal heat demand in the new houses at peak load. Similar curves are input for intermediate and low load days. Electricity demand is assumed to increase with 1.2% per year throughout the analysis.

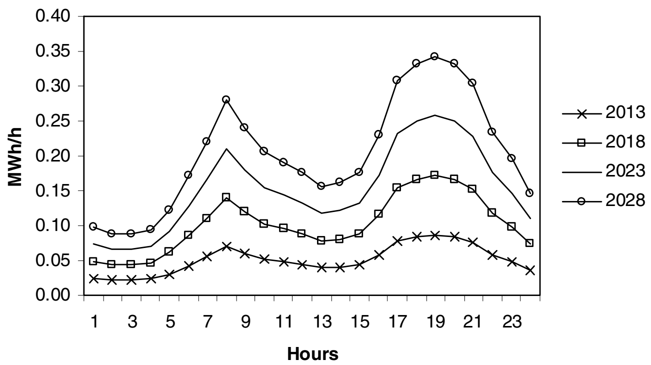

Fig. 2 Diurnal peak load heat demand in new buildings

B. Technical alternatives

In this paper, a base case and four different alternatives for energy supply are considered: a) Electric boilers, b) Ground source heat pumps, c) Gas boilers and d)

Hydrogen/FC solution with electrolyser and wind power. Figs. 3-7 show the principal layout of the different designs, omitting details of the specific networks. The full system model is shown in Fig. 8. Additional cases from the original study [23] including gas-fired CHP and district heating networks for a larger part of the municipality are omitted for simplicity.

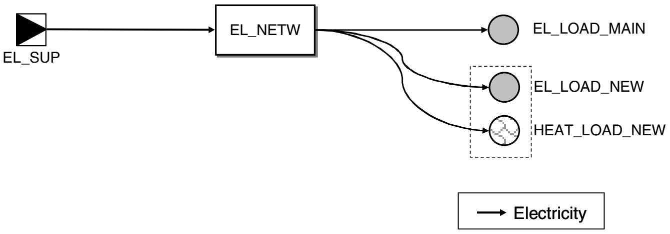

Fig. 3 Base case: Direct electric heating
(EL_SUP=Electricity supply, here Elspot market purchases)

As electricity has to be supplied to the new houses in any case, there is no extra investment cost for the energy system in the base case with direct electrical heating. There is no electricity generation in the area today, so all electricity is assumed to be purchased at the Nordic Elspot market. External electricity supply cost is in all cases assumed as typical Norwegian market prices for peak load, intermediate load and low load, respectively.

In Alternative a) the new houses do not have the opportunity to use direct electrical heating (Fig. 4). Instead, electric boilers are used for space and tap water heating. In the model 3 aggregated boilers of 100, 100 and 150 kW are used; in reality a number of smaller units would be installed. The model has the choice to install the boilers one by one during the period of analysis (in 2013, 2018 and 2023).

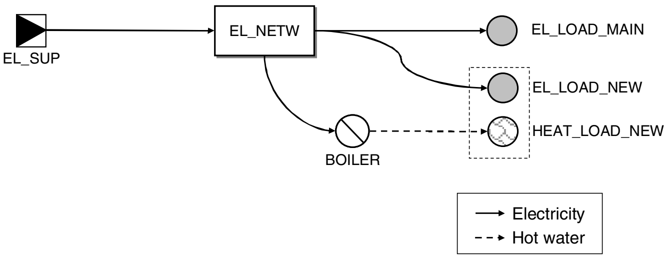

Fig. 4 Alt. a) Energy supply with electric boilers

In Alternative b) large-scale ground source heat pumps of 50 kW each are installed in a heat central (Fig. 5). When using heat pumps one needs to consider whether to use them solely for space heating or for both space and tap water heating. In the latter case, the output temperature of the heat pumps has to be higher, reducing overall efficiency. In this study, we assume an output temperature of 65^{o}C. Assuming a thermal efficiency of 60% this yields an annual heat factor of 3.4.

Also in this alternative the model is allowed to install 3 such heat pumps during the period of analysis (in 2013, 2018 and 2023). Heat pumps are generally not dimensioned to cover all heat demand so a 50 kW kerosene boiler is installed together with each heat pump to cover the peak load. Hot water storage of 150 kW capacity is also included to level out diurnal variations in the heat load.

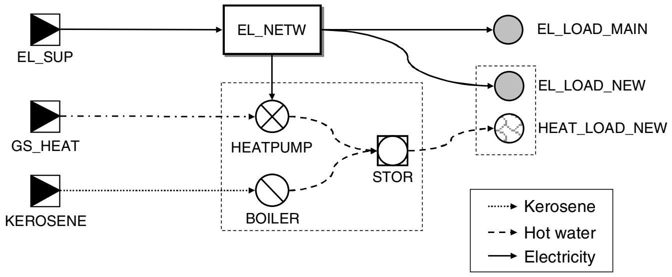

Fig. 5 Alt. b) Energy supply with heat pumps
(GS_HEAT=Ground heat source; STOR=Hot water storage)

In Alternative c) the heat pumps in the heat central are replaced by gas fuelled boilers (Fig. 6). In this alternative, the model is allowed to install three boilers of 100 kW rating in 2013, 2018 and 2023, supplying hot water for both space and tap water heating. The hot water storage of 150 kW capacity is also included. Gas supply (GAS_SUP) is assumed to be handled by road transport, and is not included in this study. The original study [23] also includes a solution with gas distribution through pipelines.

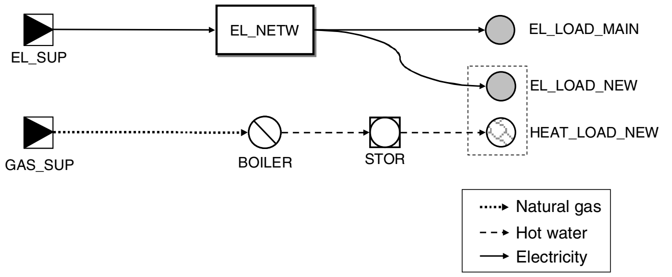

Fig. 6 Alt. c) Energy supply with distributed gas boilers

In Alternative d) a 750 kW wind turbine separate from the power grid supplies electricity directly to an electrolyser for production of hydrogen that is fed into a generic storage module (Fig. 7). An aggregated fuel cell module of 175 kW_e supplies electricity to the grid and heat to a hot water storage for domestic use. Both the electricity and heat recovery efficiency of the fuel cell are set to 35% [24]. In this case a 150 kW kerosene boiler is added to cover the peak load.

This alternative is not realistic in the present situation, but is added to the case to test the concept in comparison with the more conventional solutions.

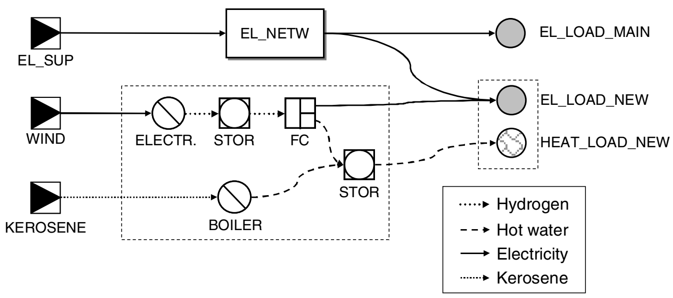

Fig. 7 Alt. d) Energy supply with RES and hydrogen

The hydronic heat distribution systems within the buildings are assumed the same in all four alternatives. This is not entirely correct, however, as some differences might be required in the technical solutions due to storage options, temperature differences between the various sources etc.

The full system model is shown in Fig. 8. The 22 kV electricity network is shown in dark blue and heat in red. Squares are various energy sources, single-coloured circles are loads and multi-coloured circles are different types of energy conversion equipment. Alternative components that do not exist initially are drawn with dashed lines. The various case alternatives are indicated in the figure.

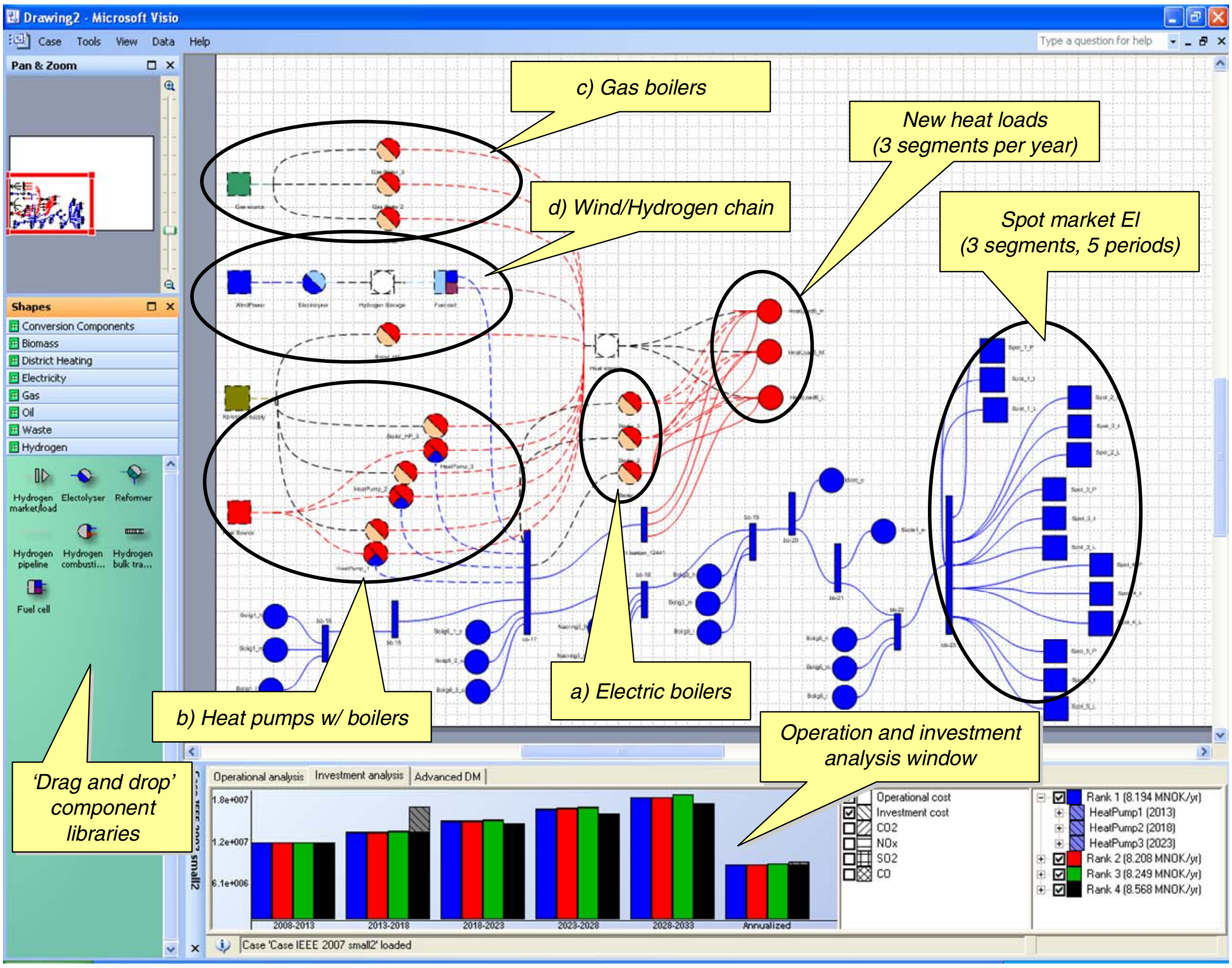

Fig 8 Alternative system designs as implemented in eTransport user interface

C. Investment and operation costs

The investment costs of the different alternatives are calculated as shown in Table I [23, 25].

The cost of kerosene is set to 0.42 USD/l (43.14 USD/MWh) and natural gas to 0.31 USD/Sm^3 (29.58 USD/MWh). Initially, Elspot market prices for 2006 including transmission tariffs are used for electricity imported to the area. The diurnal variation is between a minimum of 57.42 USD/MWh at low load night and a maximum of 74.16 USD/MWh at peak load day. During the period of analysis a flat 1% per year increase in the prices is assumed. Furthermore, it is assumed that environmental taxes and costs of emission certificates are already included in the Elspot market prices.

TABLE I
INVESTMENT COSTS

	TOTAL [1000 USD]
Alt. a) Electrical boilers (distributed) • 2,300 USD x 200 houses	460
Alt b) Heat pumps (centralized) • Heat central: 3 x (50 + 50) kW x 861 USD/kW • Distribution: 1,500 m x 308 USD/m	720
Alt c) Gas boiler (centralized) • Heat central: (3 x 100) kW x 615 USD/kW • Distribution: 1,500 m x 308 USD/m	646
Alt d) Wind/Hydrogen • Wind turbine: 750 kW x 1,230 USD/kW • Electrolyser: 750 kW x 2,090 USD/kW • Hydrogen storage: 24 kg x 517 USD/kg • Fuel cell (PEM): 175 kW x 3,700 USD/kW • Kerosene boiler: 150 kW x 461 USD/kW	3,220

In reality, Nordic Elspot prices might have large variations from year to year due to variations in hydropower availability, but this is not reflected in the present study (see also Section VII. Future Work).

IV. Numerical Results

A. Ranking of Investments

If the customers are allowed to choose direct electrical heating in their homes (no extra investments in infrastructure for the system), this alternative comes out as the most cost-effective with a total annuity of 1,256 mill USD. This reflects a common challenge for many projects in Norway related to introduction of new renewable energy sources (RES): Electricity based on existing hydropower is so cheap compared to alternatives that also require large investments that it is difficult to promote these with cost-effectiveness as the only criterion for investment decisions. To meet this challenge, municipal governments in Norway are allowed to require alternatives to direct electrical heating in new buildings through their area planning codes, e.g. hydronic space heating. In the following, we assume this is the case for this project.

With numerical assumptions as presented above, and a discount rate of 5%, the resulting ranking of the alternatives is given in Table II where the annuity is given as the sum of operational and investment costs. In this case, investments have to be initiated in 2013 for all alternatives to supply the new buildings. Since operational cost during the 25 years dominates the costs, there are relatively small differences between the annuities of the alternatives.

TABLE II
Ranking of Investments

	Year	Annuity (1000 USD/year)
1. Ground source heat pumps	2013 2018 2023	1,260
2. Gas boilers	2013 2018 2023	1,263
3. Electrical boilers	2013 2018 2023	1,269
4. Hydrogen FC with wind power	2013	1,318

The best alternative is to install heat pumps with peak load kerosene boilers in 2013, 2018 and 2023. The gas boilers come in second place, while increased operational cost puts the electrical boilers as third alternative. Due to the high investment cost, the hydrogen alternative is the last one on the ranking. Even though the difference between the annuities in Table II is small, the gas price must be reduced more than 25% before the gas boiler alternative becomes the most cost-effective one.

The ranking of the alternatives is also found in the bottom right window in Fig. 8 as an interactive tree structure that displays the components included in each alternative. Clicking on items in this list will highlight the respective component in the system drawing, making it easier for the user to identify specific components within a complex system.

The coloured columns in the analysis window show operation and investment cost for each alternative for each 5-year period, respectively (in NOK/year). The last group of columns to the right shows the resulting annuities as given in Table II.

B. System Operation

As shown in Fig. 1 the model optimizes the operation of the system hour by hour in all load segments and years to calculate annual operational costs. This is very useful for the analyst, who is able to study the behaviour of the system for each configuration alternative and load level. With the technical alternatives shown above, a number of details regarding the operation of the various designs can be analysed in the model. All diurnal variables can be displayed in the analysis window of the model. In this paper, however, the results are presented by Excel graphs rather than using screen dumps to increase the readability of the paper.

Fig. 9 shows the diurnal operation of heat pumps, kerosene boiler and storage during peak load in 2013 (after the first 50 houses are constructed). The boiler is not used during intermediate and low load level in this period.

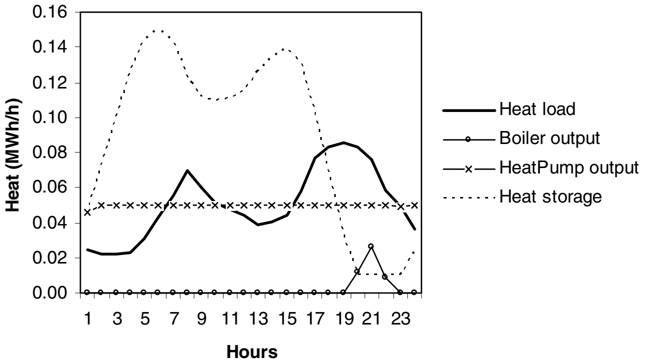

Fig. 9 Operation of first heat pump and boiler at peak load level 2013

Jumping to peak load 2028 in Fig. 10, all three heat pumps are constantly in operation during most of the day, and the kerosene boilers are also run for longer periods at rated capacity 3x50 kW. The boilers are used at all load levels, indicating that the heat pumps are under-dimensioned for this period.

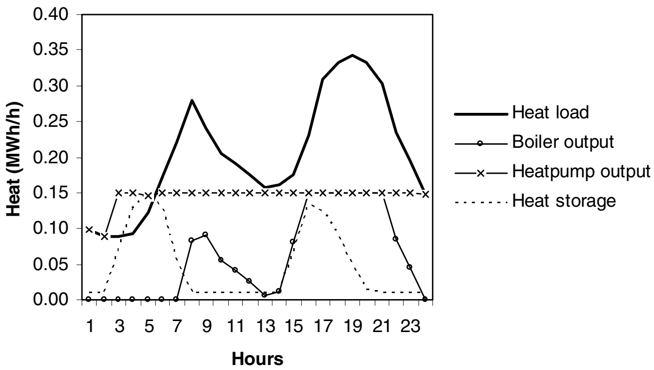

Fig. 10 Operation of heat pumps and boilers at peak load level 2028

Looking at the alternative with gas boilers at peak load 2028 in Fig. 11, we find that the boilers are used in merit order to cover the heat demand.

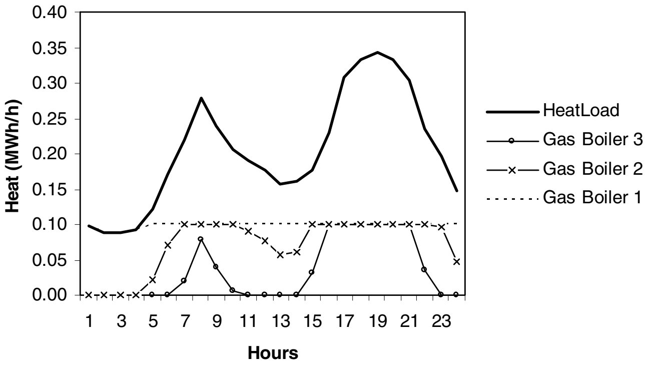

Fig. 11 Operation of gas boilers at peak load level 2028

The operation of the electrical boilers is not particularly interesting, as they keep track of the diurnal variations in the load directly. Fig. 12 shows the operation of the wind/hydrogen alternative at the same stage and load level (peak load 2028). The electrolyser is operating at constant level, feeding the intermediate hydrogen storage. The fuel cell is also operating mostly at rated level, with the boiler covering the peak load during morning and afternoon. Compared to the heat pump alternative in Fig. 10, also here the boilers are needed most of the day during peak load.

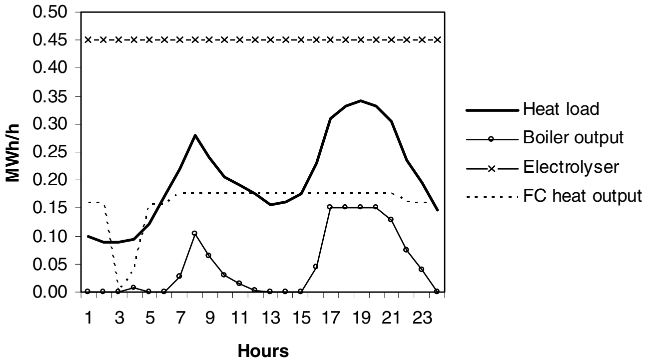

Fig. 12 Operation of electrolyser, FC and boiler at peak load level 2028

C. Emissions

Fig. 13 shows the CO_2 emissions from the four alternatives (similar graphs can be shown also for CO, NOx and SOx emissions).

Naturally, the alternative with gas boilers dominates the picture, but the use of kerosene boilers to cover peak load causes emissions also from the heat pump and wind/hydrogen alternatives. Especially in the last period (2028-2032) the emissions from the heat pump alternative increases dramatically to 45,600 kg/year. The reason for this can be seen directly from Fig. 10: The heat pumps are not able to cover the load in the last period and the kerosene boilers have to run most of the time. A similar but smaller effect is also visible for the wind/hydrogen alternative.

To mitigate the high emissions, the model is allowed to install a fourth heat pump in 2023. This does not change the priority of investments, but in Fig. 14 the reduction in emissions due to the 4th heat pump is clearly visible.

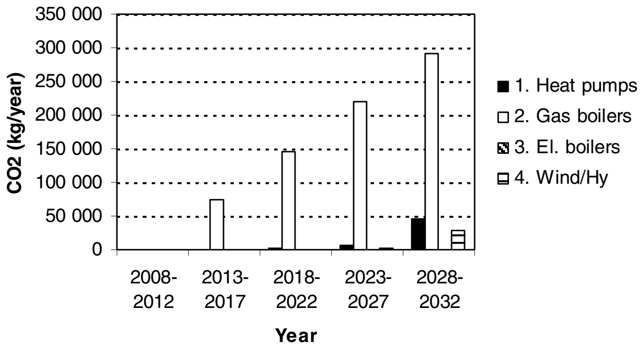

Fig. 13 CO_2 emissions for the different alternatives

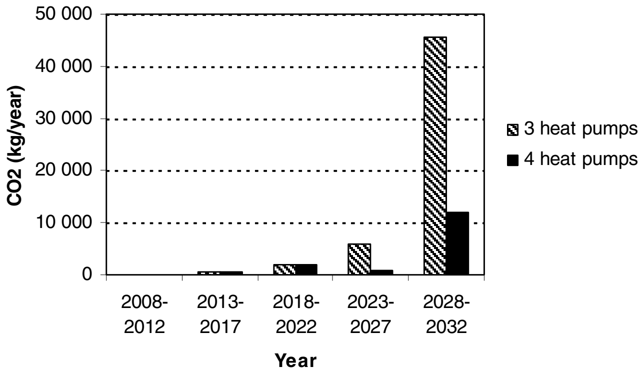

Fig. 14 Reduced CO_2 emissions for alternative with 4 heat pumps

Fig. 15 shows the corresponding operation of the components during peak load 2028 with a 4^{th} heat pump installed. Compared to Fig. 10, the boilers are now used only during the afternoon hours. All three boilers are in operation in the afternoon during the peak load period, but only one of them is used during intermediate load. None are needed during low load.

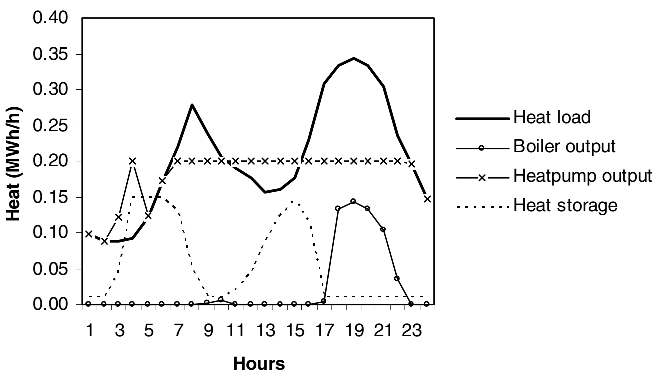

Fig. 15 Operation of heat pumps and boilers at peak load level 2028 with 4^{th} heat pump installed

V. DISCUSSION

As the main focus of this paper has been to illustrate the use of the eTransport model, less emphasis has been given to the technical parameters and the optimisation of the components themselves. It has not been the intention to give a detailed calculation of the profitability of a given investment scenario. Thus, the results presented in the previous section are based on typical cost and ratings and must be viewed as illustrations of the model rather than the final answer for the real case study.

In Norwegian case studies involving new renewable energy sources it is often a challenge to compete against direct use of electricity for space heating. During most of the year, the Nordic Elspot market is dominated by electricity generated in existing hydropower plants. The average Elspot prices are therefore so low that alternatives with large investments in new renewable technologies are less cost-effective. Even though alternative heating systems might reduce the need for investments in the electricity grid, this is not enough to make RES competitive. To meet this challenge, the new Plan and Building Act allows municipal governments in Norway to require alternatives to direct electrical heating in new buildings through their area planning codes.

In this paper, emissions were accounted for and evaluated, but it is also possible to include emission taxes directly in the model. When emission taxes are entered by the user, the costs of the emissions are included in the optimization function. As the difference in annuity between the alternatives is very small in this study, adding environmental costs (externalities) to the Elspot price and emission taxes to the kerosene and gas boilers might change the order of the alternatives.

At present, the eTransport model finds the investment with the lowest total cost among several predefined alternatives. It is not designed to optimise the size of specific components involved, so this has to be done by repeated optimisations. The model is still under development, however, and further improvements in both algorithms and component modules are expected.

VI. CONCLUSIONS

This paper has presented a case study to demonstrate the novel optimisation model eTransport. This model is designed for planning of local energy networks subject to total operation and investment cost and environmental consequences in typical municipal areas. The current version can optimize the construction of multiple infrastructures for most relevant energy carriers and conversion between these. The main task of the model is to optimize investments in infrastructure over a planning horizon of 10 to 30 years to bring available energy to the end user in such quantities and in such forms that the end users' demands are covered in the economically and environmentally best way possible.

The model optimizes the operation of the different system designs hour by hour in all load segments and years to calculate annual operational costs. Thus, it is possible to study the behaviour of the system for each design alternative and load level.

VII. FUTURE WORK

There are currently a number of research activities related to the development of the eTransport model. Several MSc students at the Norwegian University of Science and Technology (NTNU) are involved in case studies. Main topics for these students include a continuation of the Florø case used in this paper, development of new modules for cooling/low temperature systems and biomass/biofuels transport and conversion processes.

A new development project with industrial funding is also initiated that will implement stochastic optimization to enable handling of uncertainties in energy prices, demand and investments. Further improvement of the graphical user interface is also included in this project. A number of case studies will ensure a thorough testing of the model by the industrial users.

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IX. Biographies

Bjorn H. Bakken (M '98) received his MSc degree in electrical engineering from the Norwegian Institute of Technology (NTH) in 1989 and his PhD in power system operation and control from the Norwegian University of Science and Technology (NTNU) in 1997. 1990-92 he worked as Senior Engineer in a municipal power company with power generation and grid planning as main areas. Since 1997 he has been working at SINTEF Energy Research in Trondheim, Norway, where he is now Senior Scientist. Current areas of work include distributed energy resources, energy system planning and power system operation.

Hans I. Skjelbred received his MSc degree in physics from the Norwegian University of Science and Technology (NTNU) in 2004. 2004-06 he worked as researcher at SINTEF Energy Research. He is currently pursuing his PhD degree at the Norwegian University of Science and Technology with energy market modelling as main topic.

X. Appendix: Model Parameters

The following technical parameters are used in the model:

<u>22 kV power lines</u>
TXSP 1x3x150 AL, R=0.2 ohm/km, X=0.12 ohm/km

<u>Kerosene boilers</u>
- Boilers / Heat pump 1-3:
  Rating: 3x50 kW
  Efficiency: 80%
- Boiler Wind/Hydrogen:
  Rating: 150 kW
  Efficiency: 80%

<u>Gas boilers</u>
Rating: 3x100 kW
Efficiency: 90%

<u>Electricity boiler</u>
Rating: 350 kW
Efficiency: 90%

<u>Heat pumps</u>
Working temperatures (in/out): 5/65 ^{o}C
Rating: 3x50 kW
Thermal efficiency: 60%

<u>Heat storage</u>
Capacity: 150 kWh
Loss factor: 20%

<u>Electrolyser</u>
Capacity: 750 kW_e
Efficiency: 60%

<u>PEM fuel cell</u>
Capacity: 175 kW
Efficiency (el/heat): 35% / 35%

<u>Hydrogen storage</u>
Capacity: 800 kWh (24 kg H_2)
Loss factor: 10%

<u>Wind turbine</u>
Rating: 750 kW