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Towards an intermittency-friendly energy system: Comparing electric boilers and heat pumps in distributed cogeneration

Morten B. Blarke *

Dept. of Energy Technology, Aalborg University, 9220 Aalborg, Denmark

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ABSTRACT

Distributed cogeneration has played a key role in the implementation of sustainable energy policies for three decades. However, increasing penetration levels of intermittent renewables is challenging that position. The paradigmatic case of West Denmark indicates that distributed operators are capitulating as wind power penetration levels are moving above 25%; some operators are retiring cogeneration units entirely, while other operators are making way for heat-only boilers. This development is jeopardizing the system-wide energy, economic, and environmental benefits that distributed cogeneration still has to offer.

The solution is for distributed operators to adapt their technology and operational strategies to achieve a better co-existence between cogeneration and wind power.

Four options for doing so are analysed including a new concept that integrates a high pressure compression heat pump using low-temperature heat recovered from flue gasses in combination with an intermediate cold storage, which enables the independent operation of heat pump and cogenerator.

It is found that an electric boiler provides consistent improvements in the intermittency-friendliness of distributed cogeneration. However, well-designed heat pump concepts are more cost-effective than electric boilers, and in future markets where the gas/electricity price ratio is likely to increase, compression heat pumps in combination with intermediate thermal storages represent a superior potential for combining an intermittency-friendly pattern of operation with the efficient use of electricity in heating and cooling production.

1. Introduction

This paper investigates technology options that allow for distributed cogenerators to better co-exist with intermittent renewables by means of enabling a more intermittency-friendly pattern of operation. The intended energy system benefits include emission reductions and less dependency on fossil fuels, power system reliability, lower economic costs of operation in distributed generation, and improved support for local and distributed energy solutions. As such, the paper presents technology research in support of Smart Grid oriented efforts to increase energy system penetration rates for intermittent renewables. The options are analysed in the paradigmatic context of West Denmark.

By global comparison, the Danish energy system is paradigmatic in terms of integrating intermittent renewables and distributed cogeneration. In 2009, 36.4% of Denmark's electricity production originated from wind power and distributed cogeneration, which (still) represents the world's highest combined share of distributed energy.

However, studies have suggested that this electricity is in fact "unwanted" since most of it is exported [1,2], a claim which has been disputed [3,4]. Whatever the methodology, it is nevertheless clear that intermittent renewables and distributed cogeneration present a power system balancing challenge. In 2009, wind power production alone was above 50% of the net electricity demand during 1482 h, and even surpassed the net electricity demand during 47 h.

How may distributed cogeneration continue to play a key role in an energy system characterized by increasing penetration rates of intermittent renewables?

While the Danish economy has grown steadily for three decades, distributed cogeneration has been instrumental in reducing the nation's CO_2 emissions and fossil fuel consumption (Fig. 1). In combination with energy conservation measures and the development of district heating, cogeneration is the reason why, from 1985 to 2007 (pre-crisis), primary energy consumption grew by only 10%, while the economy grew by 48%. This translates into an energy elasticity of 0.25, found as the ratio of the incremental change of the logarithms of primary energy consumption and GDP. By global comparison, this is an extraordinary accomplishment. Newly industrialized countries typically suffer from energy elasticities of between 0.80 and 1.50, while other developed economies have energy elasticities of between 0.50 and 0.75 [5,6].

* Tel.: +45 9940 7213.
E-mail address: mbb@et.aau.dk

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Nomenclature

€1	=DKK 7.45 = USD 1.35
CHP	combined heat and power unit
CHP–EB	CHP with electric boiler
CHP–HP–FG	CHP with heat pump using flue gas heat
CHP–HP–FG–CS	CHP with heat pump and cold storage using flue gas heat
CHP–HP–GS	CHP with heat pump using ground source heat
COP	coefficient of performance
CS	Cold Storage
EB	electric boiler unit
FG	flue gas
G/E	natural gas/electricity price ratio
GS	ground source
HP	heat pump unit
MWe	electric capacity
MWq	heat capacity

More importantly, in this period, fossil fuel consumption and CO_2 emissions fell by 4% and 12%, respectively. This translates into a fossil fuel elasticity of −0.09 and a CO_2 elasticity of −0.32, both completely unique by global comparison. Stable economic growth in combination with decreasing CO_2 emissions and fossil fuel consumption confirms the validity of an energy strategy that has emphasized a distributed supply structure based on cogeneration and intermittent renewables.

However, today's reality is that while wind power's share of the electricity supply has been steadily increasing, the share of distributed cogeneration peaked in 2005 at 24.2% of annual electricity production, also at which point the combined share of cogeneration and wind power peaked at 42.5% of annual production. In 2009, however, cogeneration contributed only 18.3% of annual production, and the combined share of distributed energy is now lower than in 2004 (Fig. 2).

One cause of the decline is that recent policy measures have focused on distributed cogeneration when targeting problems related to critical excess supply and extreme electricity price fluctuations including the low export value of excess electricity production.

Since 2005, distributed power producers have gradually been forced to operate under spot market conditions, moving away from the feed-in tariffs under which many of them were established in the 1990s in a move to stimulate distributed cogeneration. By January 2005, all cogenerators above 10 MWe were forced away from fixed tariffs into the Nordic market exchange for electricity and carbon. In January 2007, all cogenerators above 5 MWe followed. As a result, 75% of the total distributed capacity is now operated on day-ahead electricity spot market conditions. Plants below 5 MWe may continue on feed-in tariffs until 2015.

As the historical correlation between wind power production and the day-ahead spot market price has been stable around −0.2, distributed cogenerators operating on the spot market are in fact incentivized to give way for wind power.

However, while this market-oriented measure has enabled the transition for distributed cogenerators to operate on the spot market and reduced the problem of excess production, thereby improving the co-existence of distributed cogenerators and wind power, any further significant penetration of both wind power and cogeneration does not seem to be supported without the implementation of technology-oriented measures.

So what is the nature of the ceiling which has been reached at a 40% penetration rate of distributed supply? And what may be done about the "unwanted" electricity if higher penetration rates are

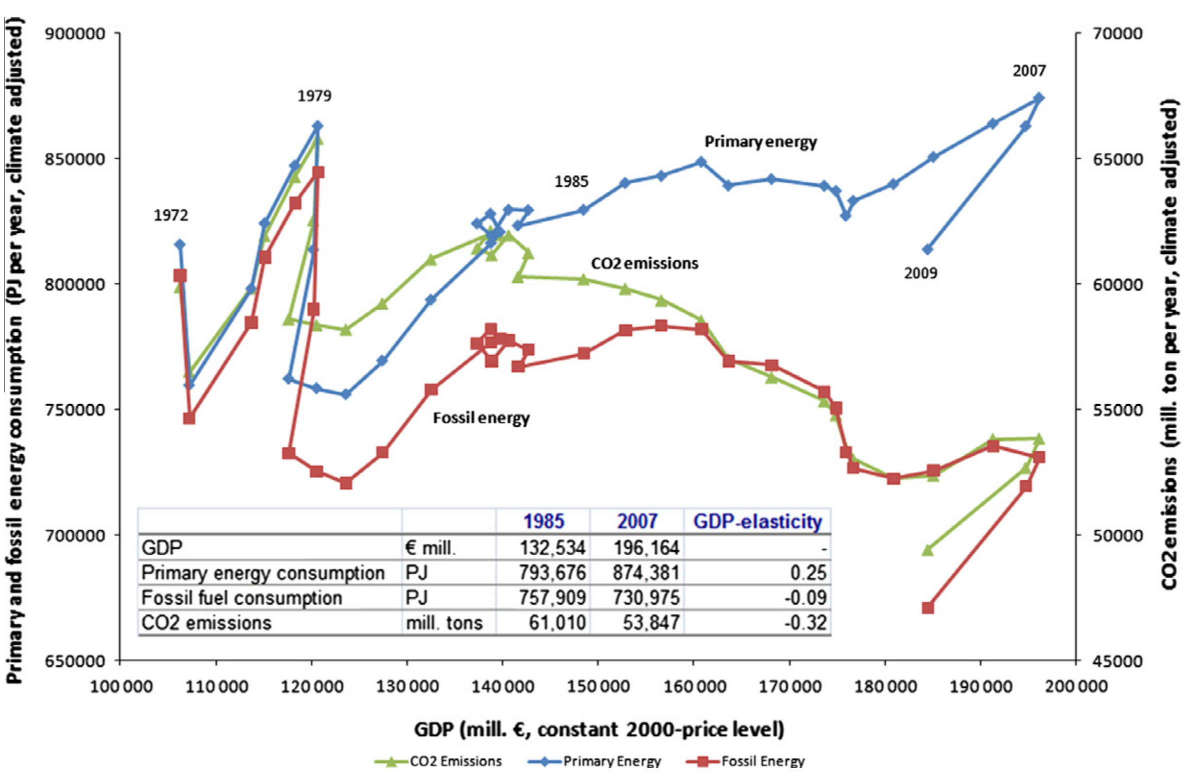

Fig. 1. The relationship between GDP development and primary energy consumption, fossil energy consumption, and CO_2 emissions. Denmark 1972–2009.

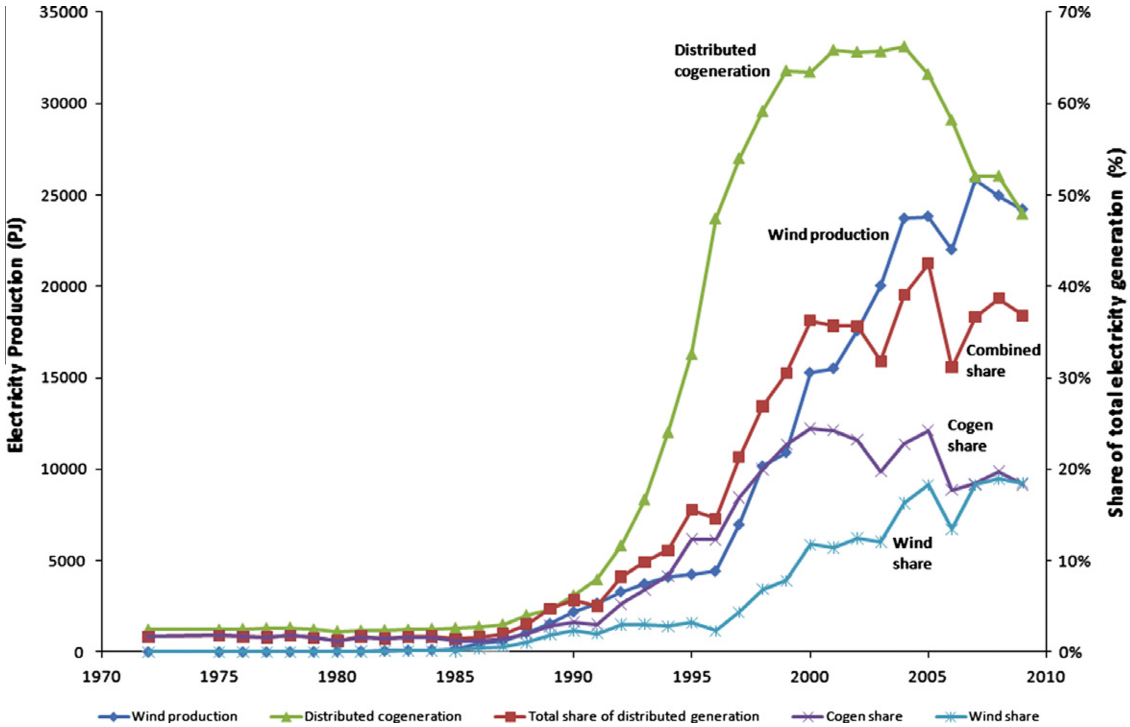

Fig. 2. Electricity production from distributed cogeneration and wind power and their shares of total annual electricity production. Denmark 1972–2009.

sought for? Or is it unrealistic to imagine an energy system primarily based on a distributed supply structure by which distributed producers efficiently provide all local heat, cooling, and mobility services? A distributed system which also autonomously handles the intermittent nature of wind power, solar energy, and wave power, perhaps completely eliminating exergetically inefficient fossil fuel-fired central power-only plants?

2. Strategies for an intermittency-friendly energy system

Previous research into renewable energy systems, distributed energy systems, Smart Grids, and Super Grids has dealt with various aspects of this challenge, including the potential role of storage and relocation technologies, cross-system exchange, intelligent control systems, and markets [7–21]. The technology changes investigated involve information and communication technology, operational control technologies, compression heat pumps and electric boilers, diurnal and seasonal thermal storages, electrical energy storage, pumped hydro storage, flywheel storage, hydrogen production and storage, compressed air energy storage, vehicle-to-grid systems, transmission technologies, and intelligent meters and flexible tariff systems for all end-users.

Fig. 3 identifies the fundamental technology components of the intermittency-friendly energy system. It appears that poly -generation and heat pumps play a central role. Poly-generation, or multi-generation, refers to the evolution of cogeneration and tri-generation into providing additional outputs such as hydrogen, ethanol, or other chemical substances used in specific processes [22]. On their part, heat pumps enable the coupling of energy carriers by using electricity for heat and/or cooling production, which may then subsequently be subject to thermal storage. Intermittent renewables are thereby integrated in the provision of heating and cooling services, while reducing the load on poly-generators, thereby assisting in balancing the supply of electricity.

It may be argued that this system design is open to two competing strategies that both serve the purpose of increasing the penetration levels of intermittent renewables: Smart Grid and Super Grid.

The ruling strategy at the level of implementation in Denmark, as well as at EU level, is cross-system exchange by transnational cabling vis-à-vis the Super Grid. In support of this strategy, the European Commission has adopted an energy infrastructure plan towards 2020 projecting a need for investing 200 billion € in transmission networks, mainly in high voltage transmission lines [23].

An alternative strategy is domestic integration vis-à-vis the Smart Grid. Under this strategy, investments are directed towards the evolution of distributed generation and end-uses, rather than towards transmission networks.

Both strategies fulfil similar policy objectives: large-scale integration of intermittent renewables, competitive markets, and security of supply. However, investing in both strategies may lead to over-investments. Furthermore, it may be claimed that the two strategies are mutually exclusive, as investing in one strategy undermines the economic feasibility of the other. This is evident as both strategies depend on the market price spread and general price level for a feasible return on investment.

So, which strategy is more cost-effective, and which strategy may provide more long-term societal and economic benefits?

The underlying hypothesis of this paper is that a domestic integration strategy towards a distributed energy system, the essence of the Smart Grid, would be an important contribution to the global pool of experiments in sustainable energy, and that Denmark is in a unique position to implement such strategy. Evidence suggests that a distributed energy system is cost-effective; it results in higher second-law system efficiencies and better supports the use of local resources to which can be added benefits from local innovation, businesses, jobs, and social coherence [24–29].

The scope of the article is to analyse options for increasing the intermittency-friendliness of distributed cogeneration, which would be supporting a Smart Grid vision for the energy system.

3. Measuring intermittency-friendliness

Blarke and Lund [18] introduces a system-specific measure *Rc* for evaluating the intermittency-friendliness of any given electricity

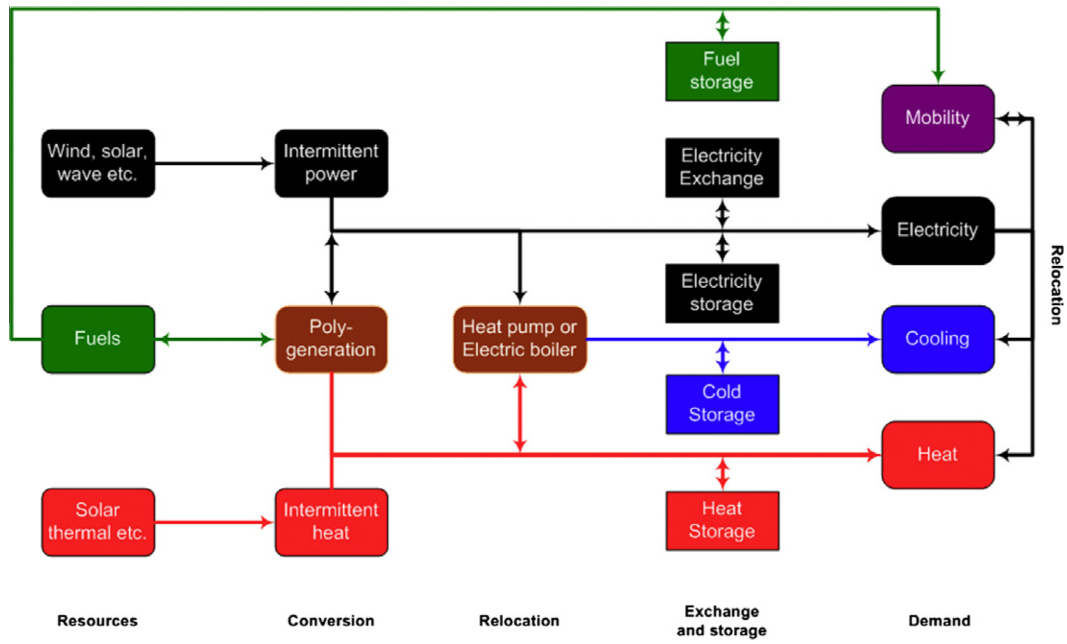

Fig. 3. The intermittency-friendly energy system.

producer or end-user. *Rc* is defined as the statistical correlation between the net electricity exchange between plant and grid, and the energy system's net electricity requirement. The net electricity requirement is defined as the electricity demand minus the intermittent electricity production.

Rc serves to evaluate the marginal "goodness" of a plant's or end-user's response to variations in net electricity requirements ranging from −1.0 to 1.0. An *Rc* of 1.0 reflects a producer in perfect accord with net electricity requirements. As such, the entire un-disrupted energy system is always characterized by an *Rc* of 1.0. An *Rc* of −1.0 reflects a producer in perfect discord with net electricity requirements, corresponding to a producer with a supply profile that mirrors net electricity requirements. An average intermittent producer will be characterized by a negative *Rc*. An *Rc* of zero means that there is no linear relationship between the producer's supply profile and net electricity requirements.

In the un-disrupted energy system all producers contribute to a combined *Rc* of 1.0. By assessing *Rc* for individual producers under various operational strategies, we have a simplified measure for maximizing the producer's intermittency-friendliness. If *Rc* for all

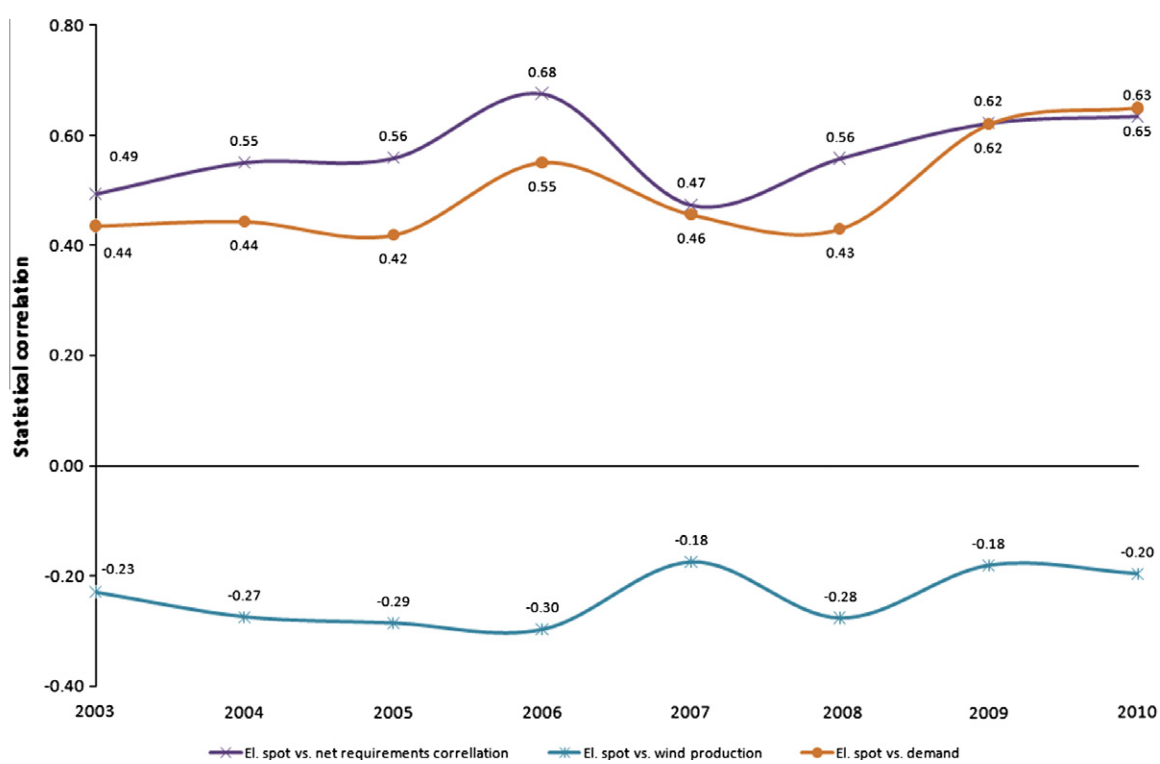

Fig. 4. Statistical correlation between electricity spot market and wind production, net electricity demand, and net requirements (net electricity demand minus wind production). West Denmark 2003–2010.

distributed cogenerators could be increased to 1.0, an energy system based entirely on distributed cogeneration and intermittent renewables would, in theory and with matching capacities, be accomplished.

However, assuming that plants are operated according to least-cost principles, one challenge is that current electricity markets do not perfectly reflect net electricity requirements. The practical range of *Rc* is therefore given by the correlation between net electricity requirements and those markets that dominate the plant's operational strategy.

Fig. 4 illustrates the development in the annual correlation between the spot market and wind power production, electricity demand, and net electricity requirements in the West Danish market area from 2003 to 2010. It appears that the practical upper limit for *Rc* for a plant operated on the spot market in this period has varied from 0.47 to 0.68.

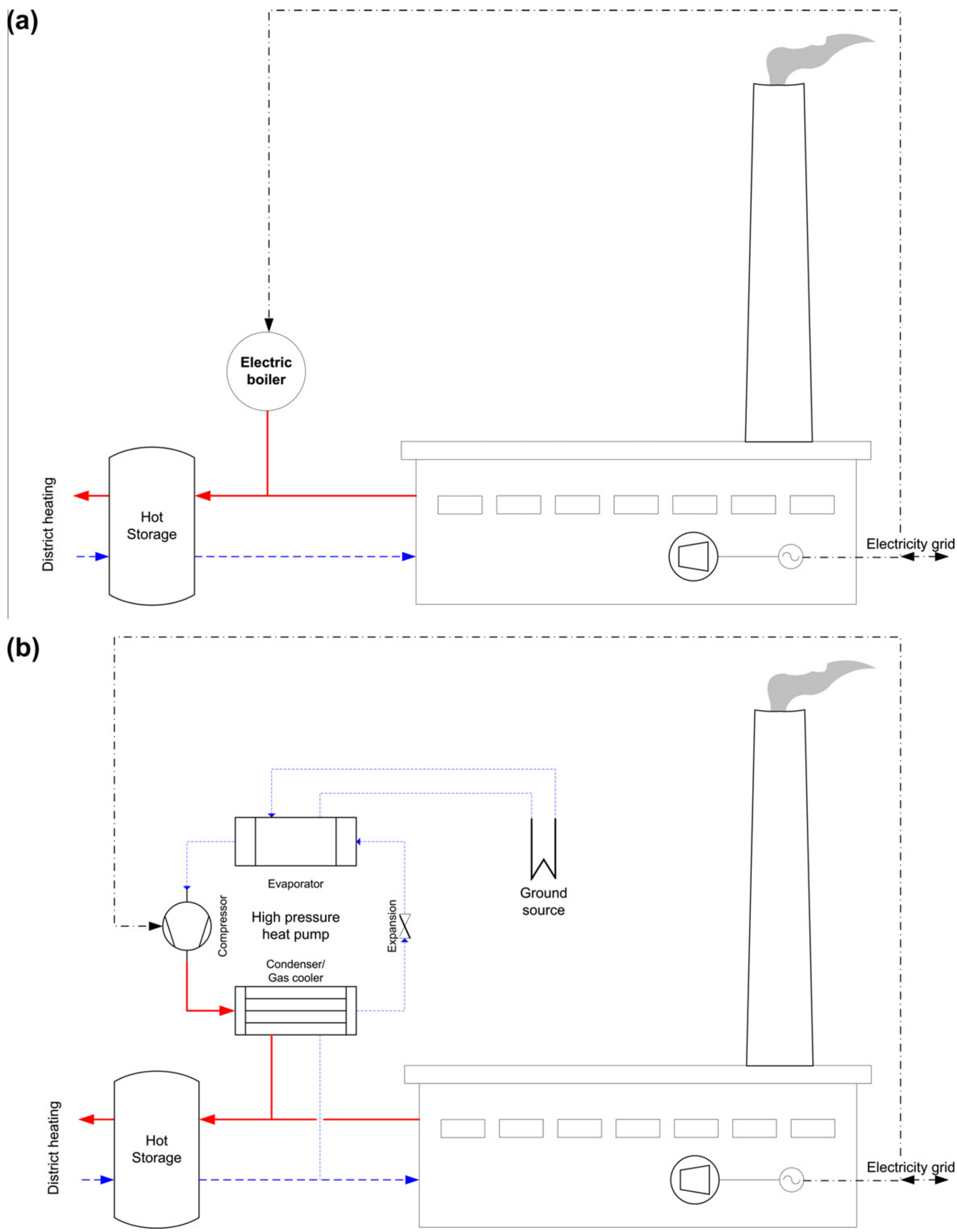

Fig. 5. The four options under analysis. CHP–EB (a), CHP–HP–GS (b), CHP–HP–FG (c), and CHP–HP–FG–CS. Heat-only fuel-fired boiler is not illustrated, but included in all concepts. Reference CHP is not illustrated, but includes CHP unit, heat-only boiler, and hot thermal storage.

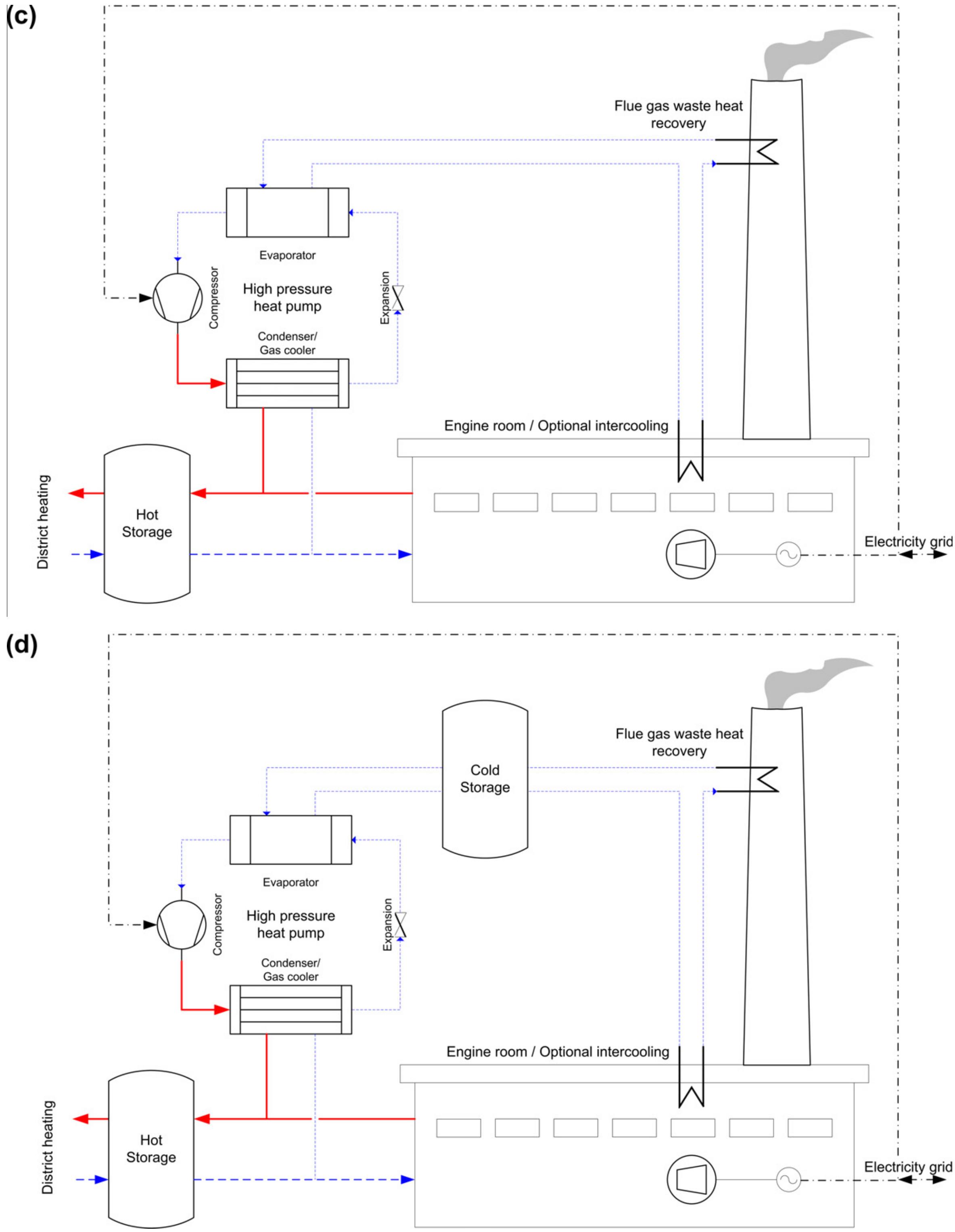

Fig. 5 (*continued*)

These values indicate the upper practical limits of *Rc* under usual techno-economic constraints and optimization criteria. Increasing the practical upper limit for *Rc* is a challenge to markets, system operators, and policy makers. Policy options for handling this challenge are further dealt with in the conclusion.

However, as the analyses below will show, the *Rc* for existing CHP operation has been constant around 0.5, thereby leaving a significant potential for improving the intermittency-friendliness in distributed cogeneration.

4. Intermittency-friendly concepts in distributed generation

Four cogeneration concepts intended to allow for increasing the intermittency-friendliness of operation are investigated. The hypothesis is that by introducing technology to existing cogenerators that allows for coupling energy carriers electricity and heat, greater operational flexibility leading to a higher intermittency-friendliness of operation is achieved. The supposedly intermittency-friendly concepts involve integrating a high-pressure

Table 1
Specific techno-economic assumptions. Capital costs include all required plant modifications and are specified as additions to other plant components. For example, the capital cost of CHP–EB is €0.6 million, while the capital cost of CHP–HP–FG–CS is €0.9 million (0.7 + 0.2).

Description	Unit	Thermal storage	Heat-only boiler	CHP	EB	HP–GS	HP–FG	CS
Capacity	–	1200 m^3 50.2 MWh	–	5 MWe	−6 MWe	−2.45 MWe	−0.35 MWe	1750 m^3 36.7 MW h
Heat capacity	MWq	–	20	6	+6	+6.125	+1.295	–
Capital cost	mill. €		–	–	+0.6	+4.9*	+0.7	+0.2
O&M cost	€ per MWh		1.0 (heat)	8 (electricity)	0.5 (heat)	1.5 (heat)	1.5 (heat)	–
Efficiency/COP	–	Simulated heat losses	0.95	0.48 (heat) 0.40 (electricity) 0.07 (heat recovery)	1.0	2.5	3.7	Simulated heat losses
Design temperatures	°C	40–80	–	–	–	8 (in) 80 (out)	25–55 (in) 80 (out)	10–50
Lifetime	Years	20	20	20	20	20	20	20

* Excl. purchase of land.

compression heat pump or an electric boiler allowing for the use of electricity to produce heat whenever feasible. In fact, the heat pump concepts also produce cooling, which in these concepts is used for heat recovery purposes.

The CHP–EB concept (Fig. 5a) adds an electric boiler (EB) enabling the plant to use electricity for producing heat for delivery or storage.

The CHP–HP–GS concept (Fig. 5b) adds an electrical compression heat pump (HP) using ground source heat (GS) as the low-temperature heat source.

The CHP–HP–FG concept (Fig. 5c) adds an electrical compression heat pump (HP) using low-pressure flue gas cooling (FG) as the only low-temperature heat source. No external low-temperature heat source is established and only concurrent operation of the CHP unit and the HP unit is possible.

The CHP–HP–FG–CS concept (Fig. 5d) further adds a water-based sensible Cold Storage (CS), which makes it possible to store low-temperature heat recovered from flue gasses when the CHP unit is in operation. When the HP unit is then operated, it utilizes the heat recovered and stored in the CS. The resulting cold water is stored for subsequent flue gas cooling. The CS represents a conceptual innovation allowing for non-concurrent operation of the CHP unit and the HP unit, though still constrained by the availability of low-temperature heat from flue gasses. Concurrent operation is also possible, whenever feasible.

In conventional district heating systems, a delivery temperature of 80 °C or higher is required. However, in the past, compression heat pumps have failed to deliver heat at this temperature level without heavily compromising the COP. Typically, systems for combined electricity, heat, and cooling production have therefore been designed for absorption heat pumps.

Today, two high-pressure compressor technologies offer an attractive combination of high delivery temperature and high COP ideal for cogeneration purposes [30]: CO_2 (carbon-dioxide/R744) transcritical piston-compressor heat pumps [31–37] and new NH_3 (ammonia/R717) heat pumps using Vilter's single-screw compressor [38]. Either technology may be applied in the HP concepts above.

5. Methodology and techno-economic assumptions

The analysis intends to compare the four options with the continued operation of an existing natural gas-fired 5 MWe distributed cogeneration reference plant with thermal storage for eight historical years (2003–2010) in West Denmark. The technology and configuration of the reference cogenerator is typical of Denmark's distributed cogenerators. Also in other countries, like Germany, where distributed cogenerators are increasingly forced to operate on spot market conditions, thermal storages are being installed allowing for some operational flexibility leading to similar "Danish" configurations in distributed generation [39]. Analysing eight historical years will allow for understanding how actual market variations, particular electricity and natural gas prices influence the operational strategies and feasibility of the options.

This section describes the methodological framework and the detailed techno-economic parameters applied in the analysis.

5.1. COMPOSE: Techno-economic modelling framework

The options are modelled using COMPOSE [40,41], which allows for techno-economic operational optimization and analysis of complex cogeneration plants. A detailed description of the modelling framework and the operational optimization program is provided in [42]. Basically, COMPOSE identifies the plant's optimal operational strategy by mixed-integer linear programming by minimizing the economic cost of heat production for each year of operation

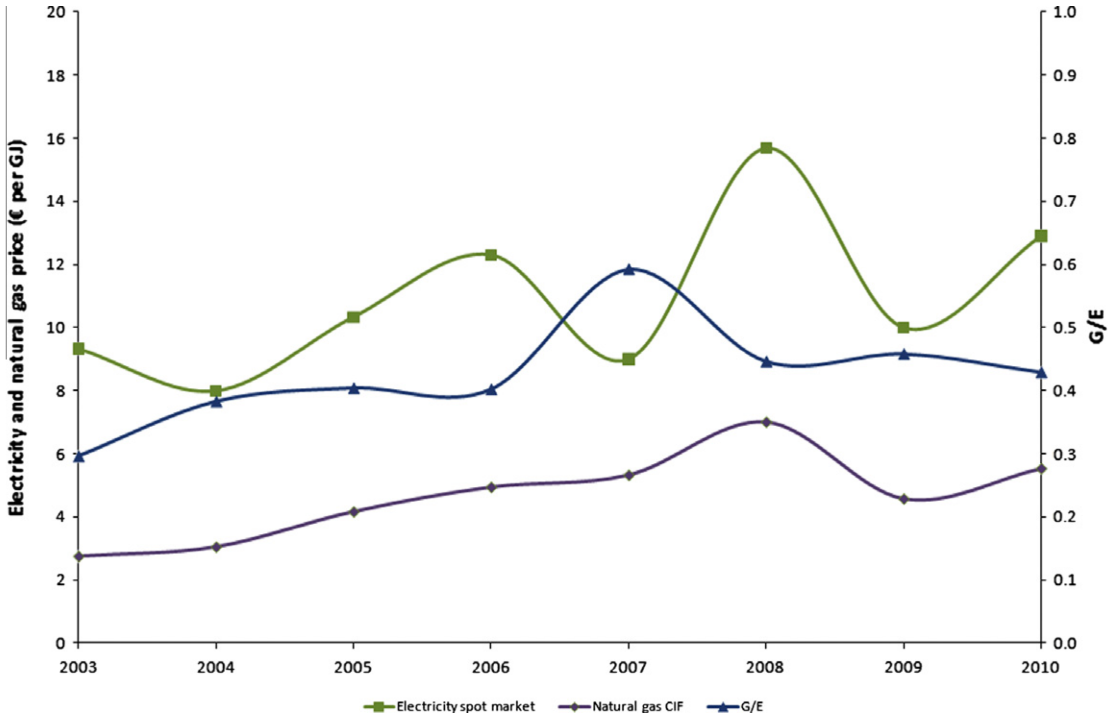

Fig. 6. Annual mean market costs excl. T&H costs for natural gas and electricity, and the G/E price ratio. In the analysis, day-ahead hourly spot market prices for electricity are used for each year. Market costs for natural gas are assumed to be constant within each year. West Denmark 2003–2010.

Table 2
General fuel, carbon, and electricity cost elements assumed to be constant for all years.

Description	Unit	Cost
Natural gas T&H	€ per MW h-fuel	4.3
Electricity T&H	€ per MW h-electricity	20
Electricity trading costs	€ per MW h-electricity	0.8
CO_2 credits	€ per ton CO_2	14

under constraint of hourly values for heating demand, market prices, O&M costs, carbon credit markets, unit capacities, etc.

In this particular analysis, all options are optimized under constraint of the heat demand, while there are no specific constraints on electricity production/consumption. Furthermore, all fiscal costs are excluded, thus enabling the evaluation of the economic activity costs, which may then subsequently form a basis for evaluating appropriate fiscal measures.

Based on the optimal least-cost operational strategy for each option in each year of operation, COMPOSE calculates the resulting

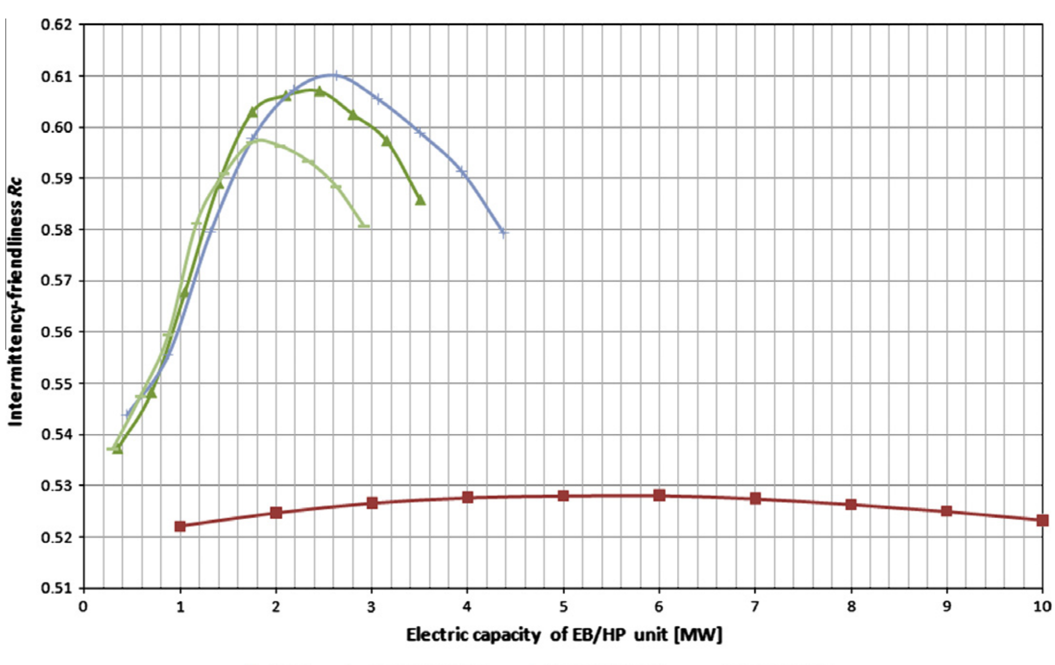

Fig. 7. Relationship between intermittency-friendliness *Rc* and the electric capacity of EB and HP-GS units. Includes sensitivity analysis for HP–GS for COP 2, 2.5 (reference COP), and 3. West Denmark 2010.

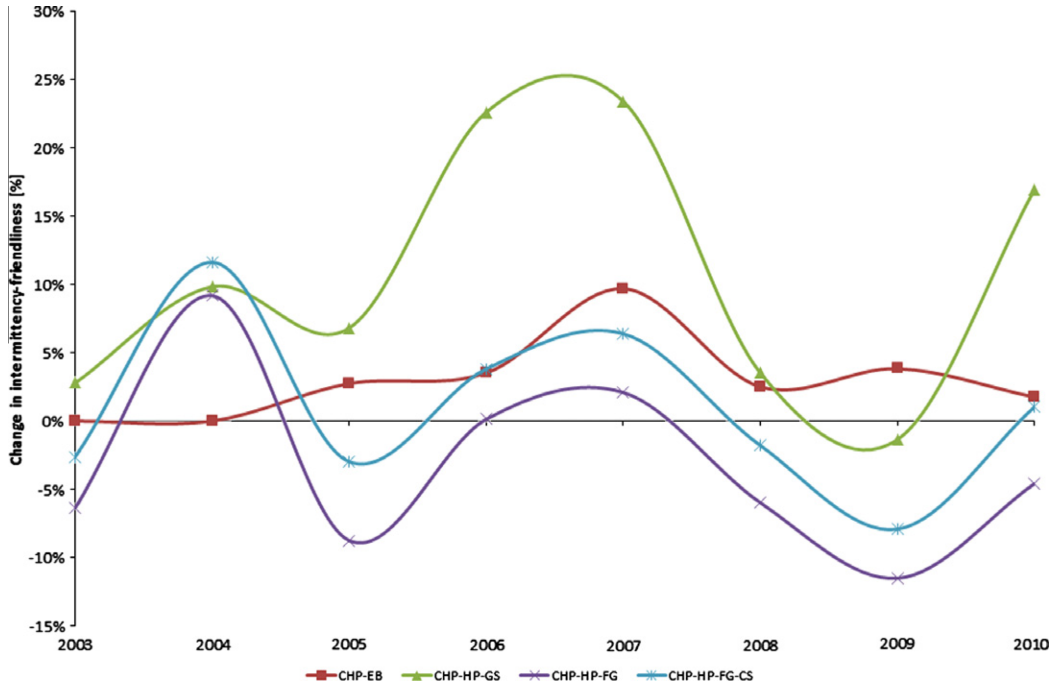

Fig. 8. Change in intermittency-friendliness *Rc* compared to CHP reference. West Denmark 2003–2010.

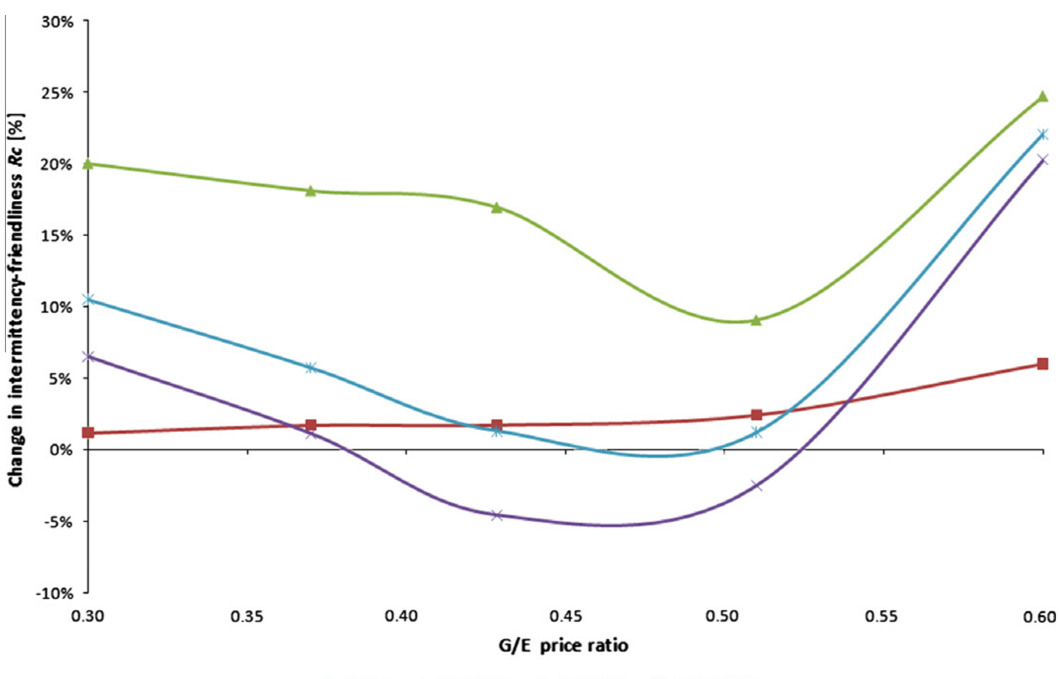

Fig. 9. The relationship between the relative change in intermittency-friendliness and the G/E price ratio for options under analysis compared to reference. West Denmark in 2010.

intermittency-friendliness, the economic annual cost of operation excluding investment costs, as well as the levelized economic cost per unit of heat delivered including annualized investment costs.

5.2. Techno-economic assumptions

Table 1 summarizes the key techno-economic assumptions including design temperature levels for each of the options described in this section.

The reference option is an existing CHP plant in district heating situated in West Denmark with two 2.5 MWe natural gas-fired engine-generators, one 20 MWq supplementary natural gas-fired boiler, as well as a 1200 m^3 water-based sensible thermal storage. The plant is typical of an estimated quarter of Denmark's distributed cogenerators.

The annual district heating requirements are 37.5 GWh of which 60% is space heating distributed according to hourly Danish Design Reference Year temperatures and degree days [43]. The remaining 40% covers the demand for hot tap water and grid losses with uniform distribution.

For option CHP–HP–FG, with both gas engines in operation, the heat available for recovery from flue gasses is 1 MWq. This corresponds to a heat recovery efficiency of 7% found by stoichiometric analysis and accomplished by cooling the flue gas from 55 °C to 25 °C. This allows for the integration of a 0.35 MWe HP unit, corresponding to 7% of the electric capacity of the CHP unit.

While the HP–FG unit capacity is determined by the heat available from flue gasses, the EB unit and the HP–GS unit capacities are not constrained by the availability of a low-temperature resource, for HP–GS assuming that sufficient ground source heat uptake is established. For these units, the optimal size is determined by maximizing the plant's intermittency-friendliness of operation.

For option CHP–HP–FG–CS, in addition to the HP–FG unit, a 1750 m^3 water-based sensible cold storage is integrated [42]. Heat losses from both hot and cold thermal storages are simulated based on a free standing tank with 100 mm Styrofoam insulation.

The heat pump's COP depends a great deal on the temperature level of the heat source. For HP–FG, recovering heat from flue gas, a practical COP of 3.7 is expected from both theoretical and

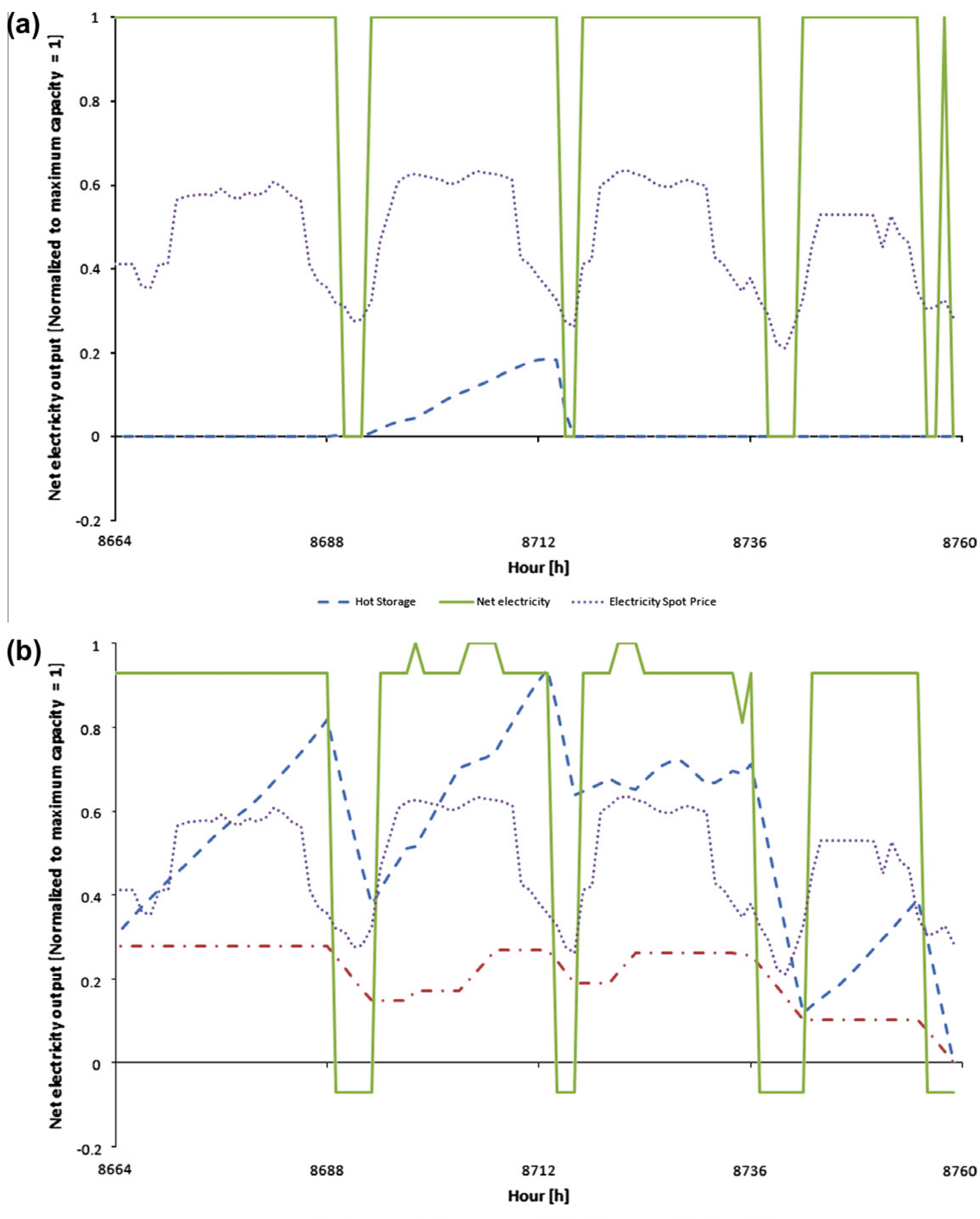

Fig. 10. Operational profiles for CHP (top) and CHP–HP–FG–CS (bottom) for the last 4 days of 2010 showing hourly values relative to annual maximum values (=1). Plotted values are thermal storage, cold storage, the plant's net electricity exchange with the grid, and the electricity price.

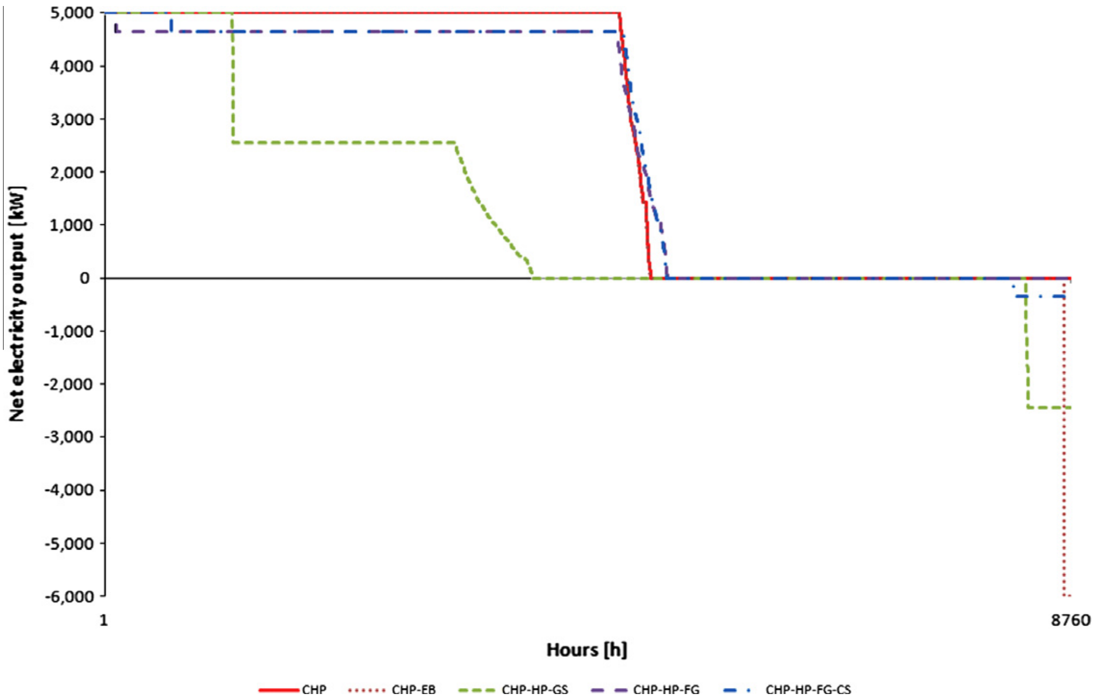

Fig. 11. Load curves showing each option's net electricity exchange with the grid. West Denmark 2010.

experimental research [31,44]. For HP–GS, relying on a constant 8 °C ground source for low-temperature heat, a COP of 2.5 is expected [45].

Capital costs and specific O&M costs included in Table 1 have been established in communication with the Danish Technological Institute [46] and leading manufacturers of high-pressure heat pumps [44,47]. Further evidence of these assumptions can be found in [31,48]. A real discount rate of 6% p.a. is applied to annualize capital costs.

All components are assumed to have a 20-year lifetime at given O&M costs. However, it must be appreciated that the lifetime and O&M costs for HP units and related equipment are subject to greater uncertainty and risk than the EB unit due to the technology status and technical complexity of high-pressure heat pumps. Other things being equal, this makes the more advanced concepts appear more favorable than they are likely to be in reality.

It is assumed that the existing CHP unit, thermal storage, and boiler can be operated for an additional 20 years at given O&M cost levels.

5.3. Fuel, carbon, and electricity costs

Fuel and electricity costs are given by actual market information for electricity and natural gas recorded for each year in this period (Fig. 6). Electricity prices vary on an hourly basis according to the actual market information for each year [49], while natural gas prices are year averages [50]. Table 2 presents the applied transmission costs for electricity, transmission and handling costs for natural gas, and carbon costs, all assumed to be constant over the period [48,51]. Electricity T&H costs are only applied to the purchase of electricity from the grid, not to the consumption of self-generated electricity.

5.4. Additional technical constraints and assumptions

The plant's electrical transmission capacity is not limited, and the plant can generate and consume electricity without

Table 3
Full-load hours of plant and EB/HP units in 2010.

Description	Full-load hours based on plant's net electricity supply (at 5 MWe) (h)	Full-load hours of non-concurrent EB or HP operation (h)
CHP	4813	–
CHP–EB	4735	62 (at 6 MWe)
CHP–HP–GS	2147	399 (at 2.45 MWe)
CHP–HP–FG	4529	–
CHP–HP–FG–CS	4554	520 (at 0.35 MWe)

constraints. For practical operation, this is considered to be a reasonable assumption.

The charge and discharge rates of the thermal storages are not limited. For practical operation, some limitation will apply due to the need to maintain thermal stratification. This is a technical design problem, which is considered to be a reasonable assumption at this point, though an improved technical model for operation of thermal storages is desired for future work.

All parameters are handled deterministically and transient operational conditions are not taken into account. For practical operation, this is not a reasonable assumption. New and more complex operational strategies will have a dynamic impact on the markets they operate in, and there will be transient deviations from steady state operational design parameters, for example when starting and stopping units. Other things being equal, any analysis applying these simplifications is likely to provide a comparative advantage for more complex operational strategies.

With respect to dynamic impacts, the analysis is limited to studying the marginal impacts, leaving the assessment of system-wide implementation programs for these new technologies and their dynamic market impacts to future studies. With respect to transient operating conditions, there is currently not sufficient experimental knowledge with these new concepts under analysis to allow for a model more reliable than the one applied.

6. Results

6.1. Sizing of EB and HP–GS by maximizing Rc

While the size of the HG–FG unit is determined by the availability of heat recovered from flue gasses, the sizes of the EB and HP–GS units are determined by maximizing the intermittency-friendliness *Rc*.

Fig. 7 shows the relationship between the electric capacity of the EB and HP–GS units and the plant's intermittency-friendliness in 2010. For CHP–EB, the optimum size of the EB unit is found to be 6 MWe corresponding to 120% of the electric capacity of the CHP unit. Extending the analysis to recent historical years (2006–2010), the optimum size of the EB unit varies from 5 MWe to 7 MWe corresponding to 100–140% of the electric capacity of the CHP unit. For CHP–HP–GS, the optimum size of the HP–GS unit is found to be 2.45 MWe corresponding to 50% of the electric capacity of the CHP unit. Extending the analysis to recent historical years (2006–2010), the optimum size of the HP–GS unit varies from 1.4 MWe to 3.15 MWe corresponding to 30–60% of the electric capacity of the CHP unit.

In subsequent analyses, the optimum unit sizes identified for 2010 are used, which are also reasonably within the optimum range identified for recent years.

As such, the plant design applies a combination of *Rc* optimal (EB, HP–GS, and CS) and physical (HP–FG) boundaries. The electric capacities of the EB (6 MWe) and HP–GS units (2.45 MWe) are significantly larger than the capacity of the HP–FG unit (0.35 MWe), the EB unit being 17 times larger while the HP–GS unit is 7 times larger. While these differences represent actual preferences in this analytical context, the different electric capacities obviously come with significant implications for the plant's electric loads during operation.

6.2. Intermittency-friendliness

Fig. 8 shows the change in intermittency-friendliness *Rc* from 2003 to 2010 for each of the four intermittency-friendly candidates compared to the CHP reference.

Most significantly, it is found that adding an EB unit consistently improves the reference plant's intermittency-friendliness, while adding an HP unit may actually result in a lower *Rc*. While a CHP plant may theoretically operate an unconstrained HP unit to increase the plant's intermittency-friendliness, a least-cost operational strategy will sometimes result in a lower intermittency-friendliness of operation. This issue relates to the low marginal costs of operating an HP unit, which allows for non-concurrent operation of the HP unit at relatively high spot market prices, while also increasing the value of concurrent operation of the CHP unit and the HP unit on the basis of self-generated electricity. This allows for the dispatch of the CHP–HP unit at relatively low spot market prices. The HP–FG option furthermore increases the value of CHP operation by relying on heat recovered from CHP unit operation. Consequently, the HP options affect the plant's operational pattern significantly.

For CHP–EB, *Rc* improves by up to 10% (in 2007). While the EB unit only marginally influences the operation of the CHP unit, e.g. winning just 63 operating hours in 2010, the EB unit will consistently improve the plant's intermittency-friendliness.

CHP–HP–GS offers significant and generally consistent *Rc* improvements of up to 23% (2006 and 2007), but may also result in a marginally lower *Rc* (-1% in 2009).

CHP–HP–FG and CHP–HP–FG–CS offer a mixed picture ranging from up to 12% *Rc* improvement in 2004 to a -12% reduction in 2009. Importantly, the CS addition consistently allows for the HP–FG unit to be operated more intermittency-friendly. In this analytical context, this is a key result showing that the CS – which

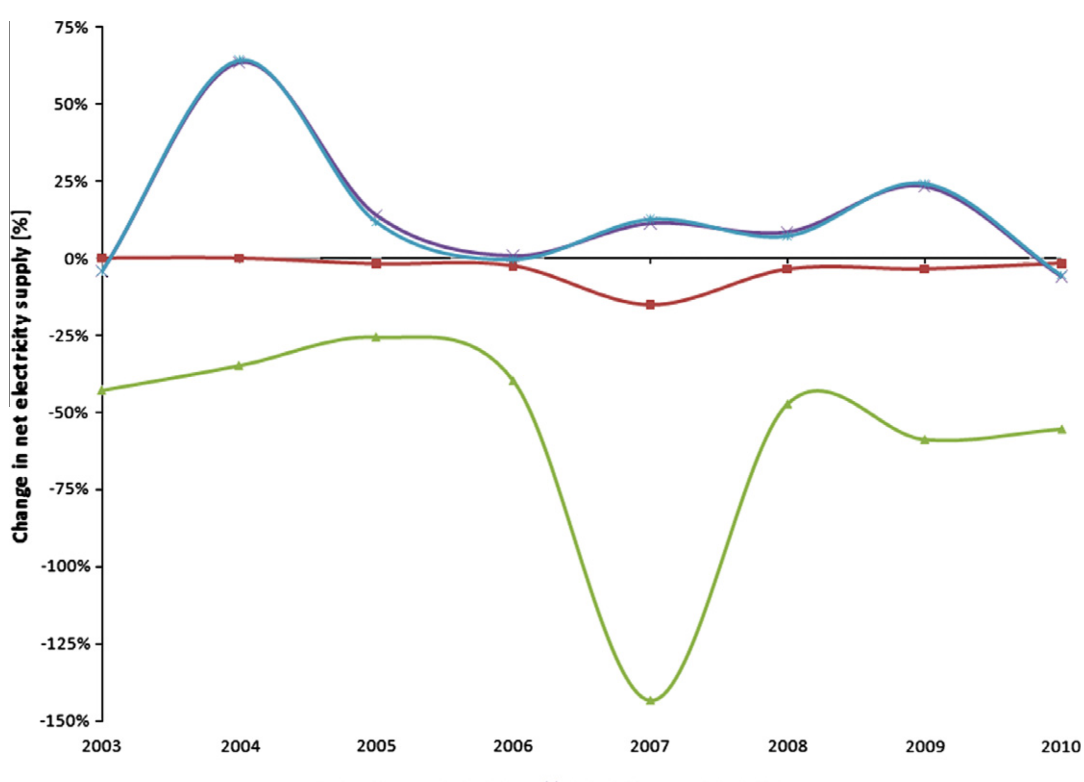

Fig. 12. Change in annual net electricity supply compared to reference CHP operation. West Denmark 2003–2010.

allows for storing heat recovered from FG – relaxes the constraint of depending upon this heat source and improves the intermittency-friendliness of HP–FG, providing a validation of the innovative CHP–HP–FG–CS concept in this respect.

The results show that attention must be directed towards the risk that low marginal costs of operating an HP unit may outweigh the potential advantages of adding an HP unit under a least-cost operational strategy.

Does this mean that HP units are not relevant for increasing the intermittency-friendliness in distributed cogeneration? Well, the results indicate that in current markets, we can only count on EB units to do just that. However, as it appears from Fig. 9 that plots the relationship between the gas/electricity price ratio G/E and the change in *Rc* in 2010, the ability of the HP concepts to improve *Rc* is highly sensitive to G/E. In 2010, the G/E price ratio is 0.43, but as the G/E price ratio moves towards 0.6, all HP concepts allow for improving *Rc* by 20–25% (ceteris paribus). This indicates the potential for HP concepts in future energy systems, as future markets are likely to be seeing higher G/E price ratios due to increasing costs of gas and oil in combination with increasing penetration of intermittent renewables.

Fig. 9 also illustrates the possibly surprising impact that the G/E price ratio has on unit commitment in complex CHP–HP systems, particularly if the HP unit and the CHP unit are interdependent; G/E price ratios in both lower and higher ranges result in unit commitment being more responsive to variations in electricity spot market prices, which translates into an improved *Rc*, while G/E price ratios in the medium range result in unit commitment being

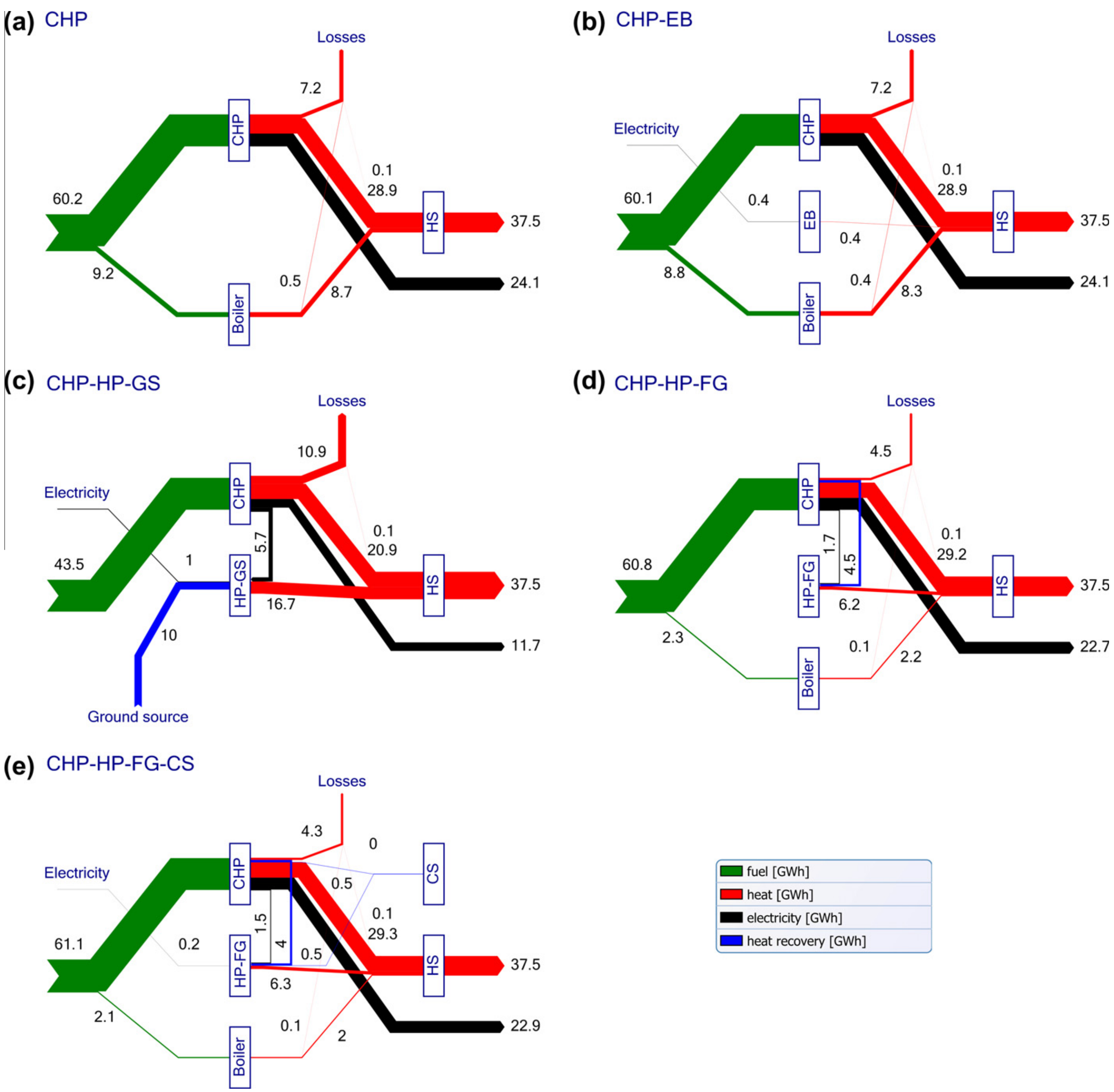

Fig. 13. Sankey diagrams for CHP reference option and the four alternative options. Top: CHP, CHP–EB, and CHP–HP–GS. Bottom: CHP–HP–FG and CHP–HP–FG–CS. West Denmark 2010.

less responsive to spot market price variations leading to a relatively lower *Rc*.

6.3. Detailed operational characteristics

Mainly serving the purpose of illustrating the process of unit commitment, Fig. 10 shows a sample for the last 4 days of 2010 of the programmatically obtained least-cost operational profile of CHP and CHP–HP–FG–CS. It is seen that the CHP reference option favors CHP unit operation, shifting to boiler operation and thermal storage usage only during very low electricity spot market price periods. The CHP–HP–FG–CS option favors concurrent operation of the CHP unit and the HP unit (CHP–HP–FG), also utilizing the thermal storage. Noticeably, the CS is utilized during 4 periods of non-concurrent operation of the HP–FG–CS unit. The CS is only filled when the CHP unit is in operation without concurrent operation of the HP unit, as concurrent operation of the CHP unit and the HP unit requires all heat recovered from flue gasses directly.

Fig. 11 shows the resulting load curves for each option in 2010 with the resulting full-load hours presented in Table 3. For CHP–EB, while the 6 MWe capacity of the EB unit significantly impacts the range of the load curve, the number of full-load hours is reduced by only 2%. The EB unit is in operation without concurrent operation of the CHP unit for just 63 full-load hours. For CHP–HP–GS, the load curve is significantly affected, reducing the number of full-load hours by 55%. The 2.45 MWe HP unit is in operation without concurrent operation of the CHP unit for 399 full-load hours. For CHP–HP–FG and CHP–HP–FG–CS, the number of full-load hours is reduced by 5–6%. For CHP–HP–FG–CS, the 0.35 MWe HP unit is in operation without concurrent operation of the CHP unit for 520 full-load hours.

Fig. 12 shows the change in the plant's annual net electricity supply for each option in all years under analysis. The unconstrained options CHP–EB and CHP–HP–GS reduce the net electricity supply in all years, most significantly for CHP–HP–GS for which the reduction generally is 25–50%. The constrained HP–FG options generally increase the plant's net electricity supply (though not in 2010), e.g. in 2009 by 23–24%. The HP–FG–CS option results in the highest increase. The high negative correlation between the electricity spot market price and the HP–FG options' net electricity supply explains the lower net electricity supply in 2003 and 2010, when the G/E price ratio is relatively low.

6.4. Sankey diagrams

Fig. 13 illustrates the energy balance flows using Sankey diagrams for each option in 2010. While the operational impacts vary from one year to another and are particularly sensitive to the G/E price ratio, a number of general observations are offered.

While CHP–EB results in only marginal changes in the plant's energy balance, the HP options significantly impact both CHP unit and boiler operation. None of the options result in any very significant purchase/import of electricity, but the HP concepts result in significant consumption of self-generated electricity. Noticeably, CHP–HP–GS significantly reduces the plant's net electricity supply, in 2010 by 55%, while also completely eliminating boiler operation.

6.5. Economic costs of operation

Fig. 14 shows the changes in annual cost of operation excluding capital costs. The highest operational cost reduction is achieved for CHP–HP–GS, which offers a 21–33% reduction during the period. The CHP–EB offers an operational cost reduction of less than 1%, while the CHP–HP–FG options reduce operational costs by 5–13%. The addition of CS to HP–FG reduces the annual costs of operation by about one additional percentage point.

Taking investments and lifetimes into account, and applying an economic discount rate of 6%, Fig. 15 shows the levelized costs of delivered heat. The CHP–HP–GS option results in significantly higher levelized production costs, reflecting that even as CHP–HP–GS offers the highest operational annual cost reduction, the HP–GS investment costs are very high. In fact, CHP–EB and CHP–HP–GS are both consistently unfeasible.

The CHP–HP–FG options reduce the levelized costs by 2–4% during 2008–2010. The HP–FG–CS option results in levelized production cost that is 1–2 percentage points higher than the HP–FG

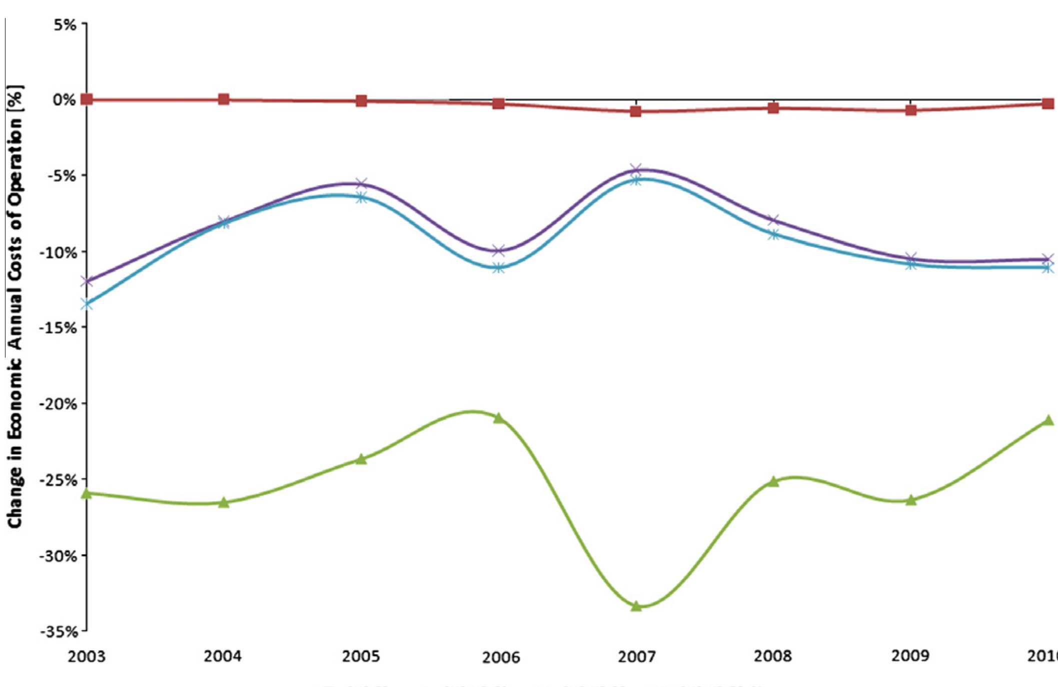

Fig. 14. Change in economic annual costs of operation (excl. investments) for options under analysis compared to reference. West Denmark 2003–2010.

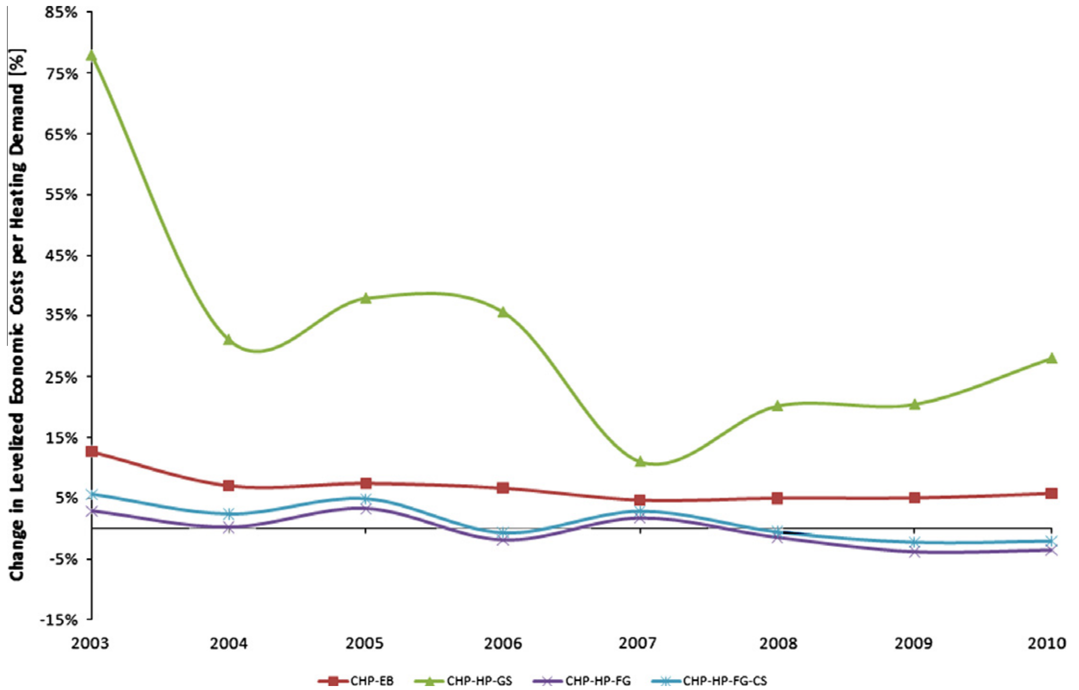

Fig. 15. Change in levelized economic heating costs based on a single year of operation compared to reference CHP (incl. annualized investments). West Denmark 2003–2010.

option, which indicates that while the addition of a CS offers lower annual costs of operation, this reduction is not sufficient to make up for the added investment.

This result is sensitive to both lifetimes and discount rate. A lower discount rate would reduce the levelized costs of all options. For example, applying an economic discount rate of 3% would result in lower levelized operational costs for all HP–FG options compared to the reference CHP option from 2006 onwards.

6.6. Cost-effectiveness of intermittency-friendliness

Aiming at increasing the intermittency-friendliness of operation under constraint of costs, it is meaningful to establishing the cost-effectiveness of increasing *Rc*. For this purpose Blarke and Lund [18] introduces the *Rc* shadow cost, which conveys the levelized cost of increasing *Rc* by one point (=0.01).

Focusing on 2010 for which CHP–EB, CHP–HP–GS, and CHP–HP–FG–CS all offer a higher *Rc*, it is found that while CHP–EB and CHP–HP–GS offer *Rc* improvements at a shadow cost of 51,000 € and 26,000 € per *Rc*-point respectively, CHP–HP–FG–CS offers a combination of *Rc* improvements and lower levelized production costs, resulting in a positive shadow *benefit* of 24,000 € per *Rc*-point. In climate policies, where CO_2 shadow costs are calculated and compared in a similar manner, such options are often referred to as "no regret" or "win–win" options.

Thus, the results indicate that while the CHP–HP–FG–CS option offers only a minor improvement of *Rc* (0.5 point in 2010 equal to 1% over reference CHP), the combination of higher *Rc* and lower levelized production costs makes it the most cost-effective option for increasing the intermittency-friendliness of operation in distributed cogeneration in 2010.

While this analysis compares options within a narrow scope of an existing distributed cogenerator, the cost-effectiveness results and the *Rc* shadow cost methodology may be extended to other energy system options that allow for increasing the intermittency-friendliness of service. This will make it possible to identify cost-effective options to support intermittent renewables across service sectors.

7. Conclusion and discussion

This study has examined the effects of integrating electric boilers (EB) and compression heat pumps (HP) with existing cogenerators in West Denmark. By global comparison, West Denmark is a paradigmatic case due to the region's high penetration rates of intermittent supply and distributed cogeneration.

The study's point of departure has been the challenges that operators in distributed cogeneration face in energy systems with increasing penetration levels of intermittent renewables. It was hypothesized that an important part of the solution could be for distributed operators to adapt their technology and operational strategies to achieve a better coexistence between cogeneration and wind power.

On the basis of historical markets for electricity and natural gas, and historical system information, four potentially intermittency-friendly concepts have been compared to the continued operation of an existing natural gas-fired cogenerator in district heating. Each concept has been simulated on an hourly basis for each year of operation with the objective of minimizing the annual economic cost of operation.

It is found that EB offers minor but consistent improvements in intermittency-friendliness *Rc*, while the HP concepts offer a higher improvement potential in future markets as the G/E price ratio increases due to increasing costs of gas and oil in combination with increasing penetration of intermittent renewables.

The innovative concept for integrating a CS for storing heat recovered from Flue Gas (FG) is found to reduce the constraints of the FG heat source and improve the intermittency-friendliness of HP–FG.

The highest *Rc* improvement potential and operational cost reductions are found for HP–GS. However, high investment cost makes this option unfeasible. While HP–FG–CS provides a significantly lower *Rc* improvement potential, it does so more cost-effectively, in 2010 qualifying as a "no regret" option providing both higher *Rc* and lower levelized production costs.

However, the analysis reveals a challenge for the otherwise generally feasible HP–FG options to consistently allow for improving the intermittency-friendliness. In fact, only the HP–GS option provides high and generally consistent *Rc* improvements, but at very high investment costs.

Nonetheless, on a more speculative note, as policy makers are already prepared to invest in grid infrastructure for handling increasing penetration levels of renewables, higher costs in distributed cogeneration may be covered, in so far as they provide intermittency support and can replace transmission grid investments. A potential financing mechanism could be to reallocate part of the existing 200 billion € Super Grid infrastructure budget [23]. Rather than investing in high-voltage cables, EU could provide more general support to options to increase the intermittency-friendliness in the energy system infrastructure.

The analysis does not allow for picking any certain winner with respect to increasing the intermittency-friendliness in distributed cogeneration, but calls for a strategic development that strikes a balance between the efficient use of electricity, the potential for increasing *Rc*, and the cost-effectiveness of doing so. A long-term technology strategy for promoting intermittency-friendliness in distributed cogeneration should preferably allow for building experimental experience with all of the options under analysis here, preferably giving short-term preference to the more cost-effective options, like EB and HP–FG–CS. In the long term, the analysis shows that HP–GS provides an option that allows for distributed cogenerators to significantly be supporting higher penetration levels of renewables.

With respect to options to improve the economic feasibility of the HP options, the HP technology should be acknowledged for its ability to provide heating and cooling simultaneously. For example, by providing cooling services for buildings [52], rather than being used for heat recovery, as suggested in this analysis, HP operation could provide additional operational revenues, while also further increasing the overall energy system efficiency.

Finally, the results suggest that policies intended to reap the potential for higher intermittency-friendliness in distributed generation must focus on the G/E price ratio. A higher G/E price ratio would have a significant effect on the ability of distributed cogenerators to co-exist with intermittent renewables. However, influencing the G/E price ratio and other fossil fuel electricity price relationships is not straightforward for national policy makers, as these relationships are subject to a range of factors. One option would be to focus on reducing the market prices for electricity, which may be accomplished by subsidizing intermittent renewables. This measure may seem counterintuitive as further increasing the penetration rates of intermittent renewables would worsen the balancing challenges that distributed cogenerators are trying to deal with. However, as a higher G/E price ratio would incentivize operators to invest in far more intermittency-friendly options, choosing HP options rather than EB options, a more permanent and effective balance between distributed cogeneration and intermittent renewables could be achieved.

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