Smart intermittency-friendly cogeneration: Techno-economic performance of innovative double storage concept for integrating compression heat pumps in distributed cogeneration

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Abstract

Increasing penetration levels of intermittent renewables are posing challenges to system operators and electricity producers. In West Denmark, which is a paradigmatic case by global comparison in terms of combining intermittent renewables and distributed cogeneration, we find that distributed cogeneration plants rather than central power plants are giving way for wind power in the electricity mix. Could intermittent renewables be a threat to the system-wide energy, economic, and environmental benefits that distributed cogeneration have to offer?

This paper investigates how existing cogeneration plants may adapt their plant design and operational strategy to improve the co-existence between cogeneration and intermittent renewables.

A novel intermittency-friendly and super-efficient concept in cogeneration is presented that involves integrating a high-pressure compression heat pump using heat recovered from flue gasses as the only low-temperature heat source, furthermore applying an intermediate cold storage allowing for non-concurrent operation of heat pump and cogeneration unit.

The novel concept is subject to a detailed techno-economic comparative modelling and analysis, which finds the concept to be the most cost-effective option for increasing intermittency-friendliness.

*Keywords:* Intermittent renewables; Smart Grid; distributed cogeneration; CO₂ compression heat pump; cold storage; thermal storage.
1. Introduction

During three decades of steady economic growth, distributed cogeneration has been instrumental in reducing Denmark’s CO₂ emissions and fossil fuel consumption.

Fig. 1 illustrates the relationship between GDP development and primary energy consumption, fossil energy consumption, and CO₂ emissions in Denmark from 1972 to 2010. 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 most other developed economies exhibit energy elasticities of between 0.50 and 0.75 [1,2]. During the same period, fossil fuel consumption and CO₂ emissions fell by 4% and 12% respectively. This translates into a fossil fuel elasticity of -0.09 and a CO₂ elasticity of -0.32, numbers which are also unique by global comparison.

Steady economic growth, decreasing dependency on fossil fuels, and decreasing CO₂ emissions, confirms the validity of an energy policy that has emphasized a distributed supply structure based on cogeneration and intermittent renewables. But the combination of intermittent renewables and distributed cogeneration is increasing challenging the energy system’s current design.

In 2010, 39.7% of Denmark’s electricity production originated from the combination of wind power and distributed cogeneration, which (still) represents the world’s highest combined share of distributed energy supply. This is however lower than in 2005 when the combined share peaked at 42.5% of annual production. In fact, while wind power’s share of the electricity supply has been steadily increasing to reach 20.2% in 2010, the share of distributed cogeneration peaked in 2005 at 24.2% of annual electricity production. But in 2010, the share of distributed cogeneration is only 19.5%, which is lower than in 1998 (Fig. 2).

The question is whether it is possible for distributed cogeneration to continue to play a key role in an energy system characterized by increasing penetration levels of intermittent renewables? Or could it be that the balancing challenges associated with intermittent renewables will slowly eliminate distributed cogeneration in favour of less operationally constrained power-only generation and heat-only boilers, possibly jeopardizing the efficiency and environmental advantages of cogeneration?

This paper challenges this development by exploring how the integration of modern large-scale compression heat pumps and thermal storages may support operational strategies in distributed generation that improves the co-existence between cogeneration and wind power, thus supporting a distributed solution for the integration of intermittent renewables and the transition to Smart Grids.
Fig. 1: The relationship between GDP development and primary energy consumption, fossil energy consumption, and CO₂ emissions. Denmark 1972-2010.

Fig. 2: Electricity production from distributed cogeneration and wind power and their shares of total annual electricity production. Denmark 1972-2010.
2. **Intermittency-friendly concepts in distributed generation**

Two cogeneration concepts that involve integrating a high-pressure compression heat pump are investigated.

The CHP-HP-GS concept (Fig. 3a) adds an electrical compression heat pump (HP) using an external low-temperature heat source, for example ground-source heat (GS).

The CHP-HP-FG-CS concept (Fig. 3b) adds an electrical compression heat pump (HP) using low-pressure flue gas cooling (FG) as the only low-temperature heat source. Furthermore, a water-based sensible Cold Storage (CS) is added, 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 in the CS 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 [3,4].

The paper analyses the techno-economic performance of these concepts in a system perspective in comparison to the continued operation of an existing CHP plant.

3. **Status for large-scale compression heat pumps in district heating**

A compression heat pump relies on a thermodynamic cycle that utilizes the thermal properties of a working fluid/refrigerant. As early ozone depleting chlorofluorocarbon (CFC) and hydrochlorofluorocarbon (HCFC) working fluids are being phased out by 2015 under EC Regulation 2037/200, the development of new working fluids have focused on using hydrofluorocarbon (HFC) and the natural working fluids hydrocarbons (HCs, e.g. propane), ammonia (NH$_3$), and carbon dioxide (CO$_2$).

Table 1 compares non-CFC working fluid alternatives by important non-thermal properties. The comparison comes with some reservations; For example, while NH$_3$ is highly toxic, it is also smelly, which means that even very low concentration levels will have people and animals flee to safety. On the other hand, while CO$_2$ is not really toxic, high atmospheric concentration levels may be life threatening to oxygen dependent organisms, and because CO$_2$ has no smell, people and animals are offered little warning in the case of a leak. As such, CO$_2$ may in fact be more hazardous than NH$_3$ in confined spaces.

It appears that HFCs are potent greenhouse gasses. In fact, HFCs are already subject to regulatory restrictions in the EU, and are also considered for regulatory phasing out programs, which makes HFCs less relevant for future applications. At the same time, conventional district heating systems requires a delivery temperature of 80°C or higher, which HFC-bases systems typically do no support.

This leaves us with only two high-pressure compressor technologies that are offering an attractive combination of climate-neutral refrigerant, high delivery temperature, and high COP [5]: CO$_2$ (carbon-dioxide/R744) transcritical piston-compressor heat pumps [6-12] and new NH$_3$ (ammonia/R717) heat pumps using Vilter’s single-screw compressor [13]. Either technology may be applied in the HP concepts above.

Table 2 presents two case applications using CO$_2$ and NH$_3$ high-pressure heat pumps in district heating. Appendix 1 presents the basic techno-economic data associated with these large-scale compression heat pump technologies.
Fig. 3: The two options for integrating compression heat pump with an existing CHP unit allowing for non-concurrent operation: CHP-HP-GS (a) and CHP-HP-FG-CS (b). Heat-only fuel-fired boiler - included in both concepts - is not illustrated.
Table 1: Non-thermal properties of key non-CFC working fluids.

<table>
<thead>
<tr>
<th>Refrigerant</th>
<th>HFC</th>
<th>Natural</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>HCs</td>
<td>NH₃</td>
</tr>
<tr>
<td>Global warming potential (GWP 100 years)</td>
<td>☁️ ☁️</td>
<td>☁️</td>
</tr>
<tr>
<td>1300-1900</td>
<td>3-5</td>
<td>0</td>
</tr>
<tr>
<td>Toxicity</td>
<td>☁️</td>
<td>☁️</td>
</tr>
<tr>
<td>Flammability</td>
<td>☁️</td>
<td>☁️ ☁️ ☁️</td>
</tr>
<tr>
<td>Pressure</td>
<td>☁️ ☁️ ☁️</td>
<td>☁️</td>
</tr>
<tr>
<td>Availability</td>
<td>☁️</td>
<td>☁️</td>
</tr>
<tr>
<td>Familiarity</td>
<td>☁️</td>
<td>☁️</td>
</tr>
</tbody>
</table>

Table 2: Selected existing applications of large-scale CO₂ and NH₃ high-pressure heat pumps in district heating.

<table>
<thead>
<tr>
<th>CO₂ case: Frederikshavn district heating, Denmark</th>
<th>NH₃ case: Drammen district heating, Norway</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation start 2010</td>
<td>Operation start 2011</td>
</tr>
<tr>
<td>1 MWq CO₂ heat pump (16 units)</td>
<td>15 MWq NH₃ heat pump (5 MW packs)</td>
</tr>
<tr>
<td>Heat delivery at 70°C</td>
<td>Heat delivery at 90°C</td>
</tr>
<tr>
<td>Heat recovery from waste water at +15°C</td>
<td>Heat recovery from sea source at +8/+4°C</td>
</tr>
<tr>
<td>COP: 3.1-3.4 (measured)</td>
<td>COP = 3.3 (measured) (Design COP: 3.0)</td>
</tr>
</tbody>
</table>


4. Methodology and techno-economic assumptions

The analysis compares the options in Fig. 3 for a single year of operation (2010) in West Denmark with the continued operation of an existing natural gas-fired 5 MWe distributed cogeneration reference plant. This section describes the methodological framework and the detailed techno-economic parameters applied in the analysis.

4.1. COMPOSE: Techno-economic modelling framework

The options are modelled using COMPOSE [14,15], which allows for techno-economic operational optimisation and analysis of complex cogeneration plants on the basis on real market information. A detailed description of the modelling framework and the operational optimization program is provided in [3]. 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 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 economic activity costs allowing for context-independent results.

Based on the optimal least-cost operational strategy in each year of operation, this analysis will focus on results with respect to energy balances, “intermittency-friendliness”, and cost-effectiveness.

In terms of measuring “intermittency-friendliness”, Blarke [16] introduces a system-specific measure $Rc$ for evaluating how well the operational profile of a given electricity producer or electricity end-user corresponds to electricity system requirements. $Rc$ is defined as the statistical correlation between the net electricity exchange between plant and grid $e$, and the grid’s net electricity requirements $d$, defined as the electricity demand minus intermittent electricity production.

\[
Rc = \frac{\sum_{h=1}^{H} (e - e_m)(d - d_m)}{\sqrt{\sum_{h=1}^{H} (e - e_m)^2 \sum_{h=1}^{H} (d - d_m)^2}}
\]

where $H$ is the total number of operational hours $h$ in each year of operation. Furthermore, Blarke [16] introduces a measure for evaluating the cost-effectiveness $Pc$ of increasing $Rc$ by one %-point;

\[
Pc = \frac{\sum_{y=1}^{Y} B_y - C_y}{\sum_{y=1}^{Y} (1 + i)^y} \left( \frac{\Delta Rc_y}{(1 + i)^y} \right)
\]

where $\Delta Rc_y$ is the difference in $Rc$ between an alternative option and its reference, $B$ is benefits, $C$ is costs, $i$ is the discount rate, and $Y$ is total number of years $y$ in the planning period.
4.2. Plant techno-economic assumptions

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 1,200 m$^3$ water-based sensible hot thermal storage (TS). 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 [17]. The remaining 40% covers the demand for hot tap water and grid losses with uniform distribution.

For option CHP-HP-FG-CS, 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. The optimal capacity of the HP-GS unit, as well as optimal TS and CS thermal storage sizes are later found by maximizing $R_c$. Heat losses from thermal storages are simulated based on a free standing tank with 100 mm Styrofoam insulation.

The heat pump’s COP depends on the temperature level of the heat source (Appendix 1). For HP-FG, recovering heat from flue gas, a practical COP of 3.7 is expected from both theoretical and experimental research [6,18]. For HP-GS, relying on a constant 5°C ground source for low-temperature heat, a COP of 2.5 is expected [19].

For the economic analysis, capital costs and specific O&M costs have been established in communication with the Danish Technological Institute [20] and leading manufacturers of high-pressure heat pumps [18,21]. Further evidence of these assumptions can be found in [6,22]. 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.

Table 3 summarizes the key techno-economic assumptions including design temperature levels for each of the options described in this section.

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>CHP</th>
<th>Boiler</th>
<th>HP-GS</th>
<th>HP-FG</th>
<th>TS</th>
<th>CS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>-</td>
<td>5</td>
<td>-</td>
<td>Optimized to Rec</td>
<td>-0.35</td>
<td>Optimized to Rec</td>
<td>Optimized to Rec</td>
</tr>
<tr>
<td>Heat capacity</td>
<td>MWq</td>
<td>6</td>
<td>20</td>
<td>+6.125</td>
<td>+1.295</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Capital cost</td>
<td>mill. €</td>
<td>-</td>
<td>-</td>
<td>+4.9 $^*$</td>
<td>+0.7</td>
<td>+0.1 per 1000 m$^3$</td>
<td>+0.1 per 1000 m$^3$</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>€ per MWh</td>
<td>8</td>
<td>1.0</td>
<td>1.5</td>
<td>1.5</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Efficiency / COP</td>
<td>-</td>
<td>0.48 (heat)</td>
<td>0.95</td>
<td>2.5</td>
<td>3.7</td>
<td>Simulated heat losses</td>
<td>Simulated heat losses</td>
</tr>
<tr>
<td>Design temperatures</td>
<td>°C</td>
<td>-</td>
<td>-</td>
<td>5 (in)</td>
<td>25-55 (in)</td>
<td>80/40</td>
<td>10/50</td>
</tr>
</tbody>
</table>

$^*$ Incl. heat source uptake, but excl. purchase of land.
4.3. Fuel, carbon, and electricity costs

Fuel and electricity costs are given by actual market information for electricity and natural gas for West Denmark in 2010. Electricity prices vary on an hourly basis according to the day-ahead sport market [23], while the natural gas price is based on year average [24].

Table 4 presents the transmission and distribution costs for electricity, electricity trading costs, transmission and handling costs for natural gas, and carbon costs [22,25]. Electricity transmission and distribution costs are only applied to the purchase of electricity from the grid, not to the consumption of self-generated electricity.

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas transmission and handling</td>
<td>€ per MWh-fuel</td>
<td>4.3</td>
</tr>
<tr>
<td>Electricity transmission and distribution costs</td>
<td>€ per MWh-electricity</td>
<td>20.0</td>
</tr>
<tr>
<td>Electricity trading costs</td>
<td>€ per MWh-electricity</td>
<td>0.8</td>
</tr>
<tr>
<td>CO₂ credits</td>
<td>€ per ton CO₂</td>
<td>14.0</td>
</tr>
</tbody>
</table>

Table 4: General fuel, carbon, and electricity cost elements in 2010.

5. Results

5.1. Sizing TS by maximizing Rc

Fig. 4 illustrates the relationship between TS size and the intermittency-friendliness Rc and fuel-to-energy efficiency η. The optimum TS size with respect to Rc is found at 6000 m³. The actual TS size at the plant on which the case study is based is 1200 m³. The result is suggesting that simply by increasing the thermal storage volume, a significant Rc improvement is achieved.

5.2. Sizing HP-GS by maximizing Rc

Fig. 5 illustrates the relationship between the electric capacity of the HP-GS unit and Rc. For CHP-HP-GS, the optimum size of the HP-GS unit is found to be 2.1 MWe, corresponding to 42% of the electric capacity of the CHP unit.

5.3. Sizing CS by maximizing Rc

Fig. 6 illustrates the relationship between CS size and Rc and η. The optimum size of the CS is found to be 3000 m³.
Fig. 4: $R_c$ and $\eta$ for CHP by function of thermal storage (TS).

Fig. 5: $R_c$, net electricity supply, and electricity production for CHP-HP-GS by function of HP-GS unit’s electric capacity.
5.4. Overall energy balance

Fig. 7 illustrates energy balance flows for CHP, CHP-HP-GS, and CHP-HP-FG-CS under the identified optimums. It is found that the HP options significantly impact both CHP unit and boiler operation. None of the options result in any significant purchase/import of electricity, but the HP concepts result in significant consumption of self-generated electricity impacting the plant’s net electricity delivery to the grid. Noticeably, CHP-HP-GS reduces the plant’s net electricity supply by 55%, while also completely eliminating boiler operation.

Fig. 6: $R_c$ and $\eta$ for CHP-HP-FG-CS by function of cold thermal storage (CS).
Fig. 7: Sankey diagrams for options under analysis [GWh].
5.5. Economic costs of operation

Fig. 8 shows that all alternative options lead to lower annual economic costs of operation, but higher levelized costs.

The highest operational cost reduction is achieved with CHP-HP-GS, which offers a 20% reduction. The CHP-HP-FG option reduces operational costs by 12%.

Taking capital costs into account, the levelized costs of delivered heat is higher for all alternative options. With CHP-HP-GS, the levelized costs increases by 28% reflecting that even as CHP-HP-GS offers the highest operational annual cost reduction, the HP-GS investment costs are very high. With CHP-HP-FG-CS, the levelized costs increases by only 4% and are in fact 1.5% lower than for the CHP reference with 6000 m$^3$ TS.

These results are sensitive to both lifetimes and discount rate. A lower discount rate reduces the levelized costs of all alternative options. However, even when applying an economic discount rate of 3%, levelized costs continue to be higher for the alternative options compared to the reference CHP option.

Fig. 8: $R_c$ for CHP actual, CHP with TS: 6000 m$^3$, CHP-HP-GS, and CHP-HP-FG-CS.
5.6. Intermittency-friendliness and cost-effectiveness

Fig. 9 shows that all alternative options result in improving the intermittency-friendliness $R_c$.

With CHP-HP-GS, $R_c$ improves by 25% (12.5%-point), while CHP-HP-FG-CS offers an improvement of 13% (7%-point). In itself, this is a significant result that supports the paper’s hypothesis with respect to these alternative concepts. It is found that the concepts allow for improving the system integration of distributed cogenerators in an energy system with high penetration levels of intermittent renewables.

With respect to the cost-effectiveness $P_c$ of increasing $R_c$, it is found that even though CHP-HP-FG-CS does not offer the highest $R_c$ improvement potential, it provides the most cost-effective $R_c$ improvement. As such, CHP-HP-FG-CS is found to be an important and cost-effective way to getting started integrating compression heat pumps in distributed cogeneration achieving critical knowledge in preparation for future concepts that may involve external low-temperature heat sources, or possibly cooling supply, providing higher $R_c$ improvement potentials.

![Graph showing $R_c$ for CHP actual, CHP with TS: 6000 m$^3$, CHP-HP-GS, and CHP-HP-FG-CS.](image)

**Fig. 9: $R_c$ for CHP actual, CHP with TS: 6000 m$^3$, CHP-HP-GS, and CHP-HP-FG-CS.**
6. Conclusion

The paper compares three options for increasing an existing CHP plant’s operational intermittency-friendliness, thereby supporting the co-existence between distributed cogeneration and intermittent renewables.

The first option is simply increasing the size of the plant’s thermal storage (CHP with 6000 m$^3$ thermal storage). The second option further integrates a ground-source heat pump (CHP-HP-GS). The third option is the novel CHP-HP-FG-CS concept that integrates a high-pressure compression heat pump with an existing cogenerator using heat recovered from flue gasses as the only low-temperature heat source, furthermore applying an intermediate cold storage enabling non-concurrent operation of heat pump and cogeneration unit.

All options analysed under real market condition for West Denmark in 2010. By global comparison, West Denmark is a paradigmatic case due to the region’s high penetration rates of intermittent supply and distributed cogeneration.

It is found that CHP-HP-GS offers the highest $R_c$ improvement potential due to the unconstrained nature of the heat source. However, the CHP-HP-FG-CS concept is a more cost-effective option for increasing the plant’s $R_c$. This result indicates that CHP-HP-FG-CS is an important and cost-effective solution for getting started integrating compression heat pumps in distributed cogeneration in preparation for future concepts involving external low-temperature heat sources providing even higher $R_c$ improvement potentials.

Taking capital costs into account, all options have higher levelized production costs than reference plant operation. So why would we even consider accepting higher levelized production costs from distributed cogeneration? Well, as policy makers and power sector stakeholders are already prepared to invest in grid infrastructure in order to handle increasing penetration levels of intermittent renewables, higher costs in distributed cogeneration should at least be covered to the extent that these new plants are replacing transmission grid investments. A potential financing mechanism could be established by reallocating part of EU’s existing 200 billion € Super Grid infrastructure budget [26]. Rather than investing in high-voltage cables, EU should provide general support to options that allows for increasing the intermittency-friendliness in the energy system infrastructure.

Acknowledgements

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Furthermore, I would like to thank Torben Hansen, Advansor A/S, and Thomas Lund, CoolPartners Aps, for helping to establish the most current techno-economic assumptions for the involved technology components. Finally, I would like to thank Bjarni Kristjansson, Maximal Software Inc, for providing an academic licence for OptiMax, and the Gurobi team for providing an academic license for Gurobi 4.
Appendix 1: Techno-economic data sheet for large-scale compression heat pumps in district heating

**HP CO₂ compressor unit excl. heat source uptake**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>MW heat</td>
<td>0.05 - unlimited</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +2°C</td>
<td></td>
<td>2.0 - 2.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +8°C</td>
<td></td>
<td>2.8 - 3.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +15°C</td>
<td></td>
<td>3.2 - 3.4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +30°C</td>
<td></td>
<td>3.5 - 3.8</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Investment</td>
<td>M€ per MW heat</td>
<td>0.8 - 1.0</td>
<td>0.7</td>
<td>0.6</td>
<td>0.5</td>
</tr>
<tr>
<td>Annual O&amp;M</td>
<td>€ p.a.</td>
<td>2 – 5 % of investment</td>
<td>1 – 2 % of investment</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**NH₃ compressor unit excl. heat source uptake**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>MW heat</td>
<td>0.5 - unlimited</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +2°C</td>
<td></td>
<td>1.7 - 2.6</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +8°C</td>
<td></td>
<td>2.7 - 3.3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +15°C</td>
<td></td>
<td>3.2 - 3.4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>COP at +30°C</td>
<td></td>
<td>3.5 - 4.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Investment</td>
<td>M€ per MW heat</td>
<td>0.5 - 0.6</td>
<td>0.4</td>
<td>0.4</td>
<td>0.3</td>
</tr>
<tr>
<td>Annual O&amp;M</td>
<td>€ p.a.</td>
<td>2 – 3 % of investment</td>
<td>1 – 2 % of investment</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Heat source uptake investment costs**

<table>
<thead>
<tr>
<th>Heat source</th>
<th>Source temp.</th>
<th>Unit</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ground source(^3)</td>
<td>2 - 8°C</td>
<td>M€ per MW heat(^4)</td>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sea/waste/ground water(^3)</td>
<td>0 - 15°C</td>
<td>M€ per MW heat(^4)</td>
<td>0.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Geothermal(^1)</td>
<td>30°C per km</td>
<td>M€ per MW heat(^4)</td>
<td>0.7 per km</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flue gas incl. Cold Storage(^2)</td>
<td>25 – 60°C</td>
<td>M€ per MW heat(^4)</td>
<td>0.4</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. Based on experiences from Hovedstadsområdets Geotermiske Samarbejde (HGS) where a 2.7 km deep 14 MW geothermal well project amounted to DKK 203 mill. incl. land facilities, but excluding land purchase. Water temperature at surface is 73°C. Values specified per vertical km.
2. Included refurbishing existing plant for flue gas condensation incl. stainless steel core for chimney, waste water treatment, and more.
4. Per MW heat uptake – NOT heat production capacity. Must also consider COP.
Appendix 2: Nomenclature

€1 = DKK 7.45 = USD 1.35

CHP: Combined heat and power unit
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
FG: Flue gas
GS: Ground source
HP: Heat pump unit
MWe: Electric capacity
MWq: Heat capacity
O&M: Operation and maintenance costs excluding fuel costs
Pc: Cost-effectiveness of increasing Rc
Rc: Intermittency-friendliness coefficient
TS: Hot thermal storage
η: Fuel-to-energy efficiency
References


